Scotland Whole Energy System Vision

February 2024

Foreword

The Scotland Whole System Vision explores a vision for the development of an integrated energy infrastructure for Scotland to achieve its 2045 net-zero target whilst developing a significant energy-export-based industrial opportunity. This study was made possible by the joint funding provided by National Gas Transmission and SGN. We would also like to extend our gratitude to ESO, the Scottish Government, SPEN, and SSEN for their voluntary collaboration and valuable input throughout the project. Their contributions were instrumental in providing a truly whole system view which led to the successful completion of this study.

It is becoming increasingly clear that whole system planning is crucial to achieving a net zero carbon emissions target in the UK. By taking this approach, we can find the most cost-effective solutions for customers while ensuring energy security. For example, the Gas and Electricity Transmission Infrastructure Outlook (GETIO) highlighted that whole system planning could provide around £38bn in cost savings across Great Britain.

The Scotland Whole System Vision, which was also carried out by Guidehouse as an independent expert consultancy, is a natural continuation of the GETIO study. It delves further into the intricacies and particularities of Scotland's energy system.

The study concludes that Scotland has the potential to become a leader in green industrialisation and a significant energy exporter to the rest of Great Britain and Europe. However, some evident challenges must be addressed to make the most of this opportunity, and this study takes a significant step in identifying them.

The creation of NESO to independently drive national and regional energy planning, bringing electricity, gas and hydrogen plans together is a step in the right direction. This is a complex task to do in an ever-evolving landscape, filled with uncertainty. However, we hope that this study will inform and support positive progress.

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Executive Summary

Motivation

Scotland has set an ambitious target to become **net zero by 2045.** While for many countries, reaching net zero is set to be a challenge, Scotland is in the unique situation of having the **potential to achieve this target and support others in doing so as well.** Indeed, Scotland's renewable potential is extensive and could **position the country as a leader in green industrialisation**, as well as a key energy **exporter** to the rest of Great Britain and Europe.

However, maximising the benefits of this clean energy opportunity **will require a coherent vision**, as well as extensive coordination among all actors of the energy value chain to transform vision into reality.

Key Conclusions

The cross-sector modelling conducted in this study concluded that Scotland could be **a key player in the future global energy market** thanks to competitive power and hydrogen production, and proximity to one of the world's largest demand markets. As such, Scottish exports to the rest of GB and Europe could reach up to £15 billion worth of energy commodities annually by 2045. Unlocking this opportunity requires **significant investments in both electricity and hydrogen transmission infrastructure**. These investments are needed as early as possible to increase developers' confidence and avoid delaying energy generation investments.

Stakeholders have highlighted that translating this vision into reality will require **going beyond ad-hoc engagement into true cooperation** between all actors of Scotland and Great Britain's energy sector. Cooperation, to avoid remaining a buzzword, requires concrete efforts by all actors to engage other players beyond industry forums or ad-hoc events.

Building on the demonstration that significant long-term cost savings can be made when the system is optimised over decades rather than the next regulatory period, stakeholders have also highlighted the **need to reconcile long and short-term planning** in policy and regulation. Additionally, stakeholders stressed the importance of **introducing a proper skill regime** to solve the existing and future skill shortages across the value chain.

Finally, stakeholders highlighted that **the hydrogen market is currently not set up for scale** and will require the introduction of appropriate policy, regulatory and market framework that promote hydrogen production at scale in Scotland. More importantly, stakeholders recognised that midstream infrastructure is a prerequisite to scaling the hydrogen market beyond bilateral contracts.

The actions and recommendations outlined in this section are the product of iterative modelling and extensive stakeholder engagement

1. MODELLING

Assumption development
Developed modelling assumption with core project stakeholders

Produced modelling results
Developed and iterated modelling for five months with core project stakeholders

Core project stakeholders

national gas transmission
SGN
nationalgridESO
Scottish & Southern Electricity Networks
The Scottish Government
SP ENERGY NETWORKS

2. STAKEHOLDER EVENT

Modelling results executive summary
Stakeholder event with 65 senior stakeholders from over 25 organisations

Breakout session 1
What are the barriers to realising Scotland's energy production and export opportunity?

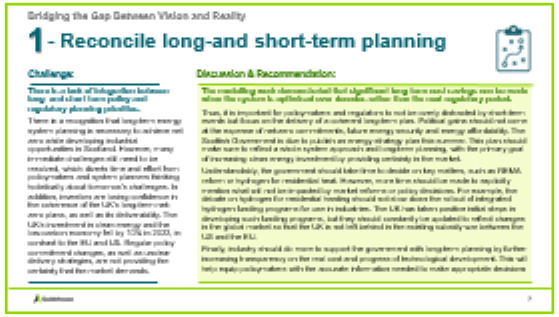
Breakout session 2
What actions are needed to transform this work from modelling to reality?

Synthesise discussion and group into key themes to develop a set of challenges for the industry to achieve the vision set out in the modelling, as well as a discussion with potential recommendations

FINAL REPORT

This final report includes:

1. A summary of the discussions from the stakeholder event's two breakout sessions, where stakeholders were divided into four groups.
2. The modelling results of the study, including key takeaways and methodology.



July 2023 – December 2023 | *February 2024* | *March 2024*

The Scotland Whole System stakeholder event gathered a wide range of stakeholders to encourage diversity of opinion in the discussion

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Core project stakeholders

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Breakout session 1
What are the barriers to realising Scotland's energy production and export opportunity?

Breakout session 2
What actions are needed to transform this work from modelling to reality?

The event gathered over **65 stakeholders from over 20 different organisations** across policy, regulatory, network and industry

1 - Reconcile long-and short-term planning

Challenge:

There is a lack of integration between long- and short-term policy and regulatory planning priorities:

There is a recognition that long-term energy system planning is necessary to achieve net zero while developing industrial opportunities in Scotland. However, many immediate challenges still need to be resolved, which diverts time and effort from policymakers and system planners thinking holistically about tomorrow’s challenges. In addition, investors are losing confidence in the coherence of the UK’s long-term net-zero plans, as well as its deliverability. The UK's investment in clean energy and the low-carbon economy fell by 10% in 2022, in contrast to the EU and US. Regular policy commitment changes, as well as unclear delivery strategies, are not providing the certainty that the market demands.

Discussion & Recommendation:

The modelling work demonstrated that significant long-term cost savings can be made when the system is optimised over decades rather than the next regulatory period.

Thus, it is important for policymakers and regulators to not be overly distracted by short-term events but focus on the delivery of a coherent long-term plan. Political gains should not come at the expense of net-zero commitments, future energy security and energy affordability. The Scottish Government is due to publish an energy strategy plan this summer. This plan should make sure to reflect a whole system approach and long-term planning, with the primary goal of increasing clean energy investment by providing certainty in the market.

Understandably, the government should take time to decide on key matters, such as REMA reform or hydrogen for residential heat. However, more time should be made to explicitly mention what will not be impacted by market reforms or policy decisions. For example, the debate on hydrogen for residential heating should not slow down the rollout of integrated hydrogen funding programs for use in industries. The UK has taken positive initial steps in developing such funding programs, but they should constantly be updated to reflect changes in the global market so that the UK is not left behind in the existing subsidy war between the US and the EU.

Finally, industry should do more to support the government with long-term planning by further increasing transparency on the real cost and progress of technological development. This will help equip policymakers with the accurate information needed to make appropriate decisions

2- Effective collaboration beyond buzzwords

Challenge:

Current market and regulatory frameworks do not incentivise value chain collaboration:

Competition between green project developers for customers and capital has significantly reduced information sharing and transparency on real project costs which prevents efficient planning.

1. The complete regulatory separation of generation and networks provided many benefits, but it also has significantly reduced coordination between upstream and midstream resulting in slower investments in both parts of the value chain.
2. The regulatory barriers for communication between electricity and gas networks do not provide the right signals for both electricity and gas network planning managers to discuss with their counterparty.
3. Current market mechanisms are fractured, with different support schemes for upstream, midstream and downstream
4. The lack of appropriate market signals and incentives leads to a lack of involvement by offtakers in system planning. Industrials often make fuel-switching decisions based on their group strategy rather than their location.

Discussion & Recommendation:

The policies and regulations introduced to drive competition and attract investment have led to a reduction in collaboration and central coordination. This liberalised cannot or should not necessarily be amended. **However, the introduction of a centrally-led industrial strategy could help coordinate the entire value chain without changing or causing disruption to the existing liberalised energy market.** This strategy would aim to coordinate regulated infrastructure investments and provide clarity to offtakers on the best available fuel-switching option while creating a framework that brings together dispersed industrial sites, as well as provides tailored financial incentives. Market-based signals are key, but often insufficient to drive effective planning.

In addition, it falls under the responsibility of all individual actors across the value chain to do more to collaborate. The benefits are clear, yet discussions only occur during industry forums.

> “*We all need to do more to coordinate, and we need to do it with a broader range of people across the value chain but also geographically, with Northern Ireland and Europe included in the discussion.*”

3 - Addressing the skill gap challenge

Challenge:

Lack of skills is slowing down progress across the value chain, from policy planning to project development:

A skilled workforce is set to be the backbone of the energy transition. However, the UK currently do not have sufficient skilled workers to prepare and face the scale of the transition. Skill shortage ranges across the value chain, from power and gas policy planning to engineering roles. This issue is exacerbated by a global competition for talent, and the division of knowledge across the GB value chain. For example, TSOs, DSOs, OFTOs, the ESO, renewables developers, and industrials all need to have highly capable electrical engineers.

Discussion & Recommendation:

Today, the pool of expertise and skilled workers available is limited. Therefore, it is important to make the best use of existing resources across the value chain by maximising knowledge-sharing across organisations and geographies. The UK has the advantage of having a single central system planner, NESO, which will independently drive national and regional energy planning bringing electricity, gas and hydrogen plans together to efficiently deliver net-zero. **It is essential to ensure that knowledge flows in and out of this organisation efficiently to benefit the entire value chain.**

Along with leveraging the current pool of knowledge and skills, a skills regime should be implemented to increase the number of trained workers across the entire value chain. The UK is in a favourable position to tackle this issue, thanks to its world-leading universities and energy-focused engineering programs. Furthermore, it has always been a hub for skilled workers from abroad. To take advantage of this strength, a central planning authority could conduct research to identify and quantify skill gaps across the energy value chain. This research should guide policy on how to fill those gaps most effectively.

> “*Skill and expertise are limited so there needs to be more information sharing between electricity and hydrogen networks. Particularly as the ESO is transitioning to NESO, we need to provide appropriate gas and hydrogen market expertise to complete ESO knowledge.*”

4- Setting hydrogen production for scale

Challenge:

The hydrogen market is not set up for scale:

The hydrogen economy requires scale. The expected hydrogen production cost reduction over the next decades can only be achieved through the development of large projects, making the best use of local resources and creating an economy of scale. However, current commercial models and market codes do not support this ambition.

1. The lack of hydrogen transmission infrastructure prevents developers from building hydrogen production capacity with a larger market in mind. Without hydrogen transmission infrastructure, volume risk cannot be alleviated as developers are forced to rely on a single or small number of offtakers for their projects.
2. The current “sales cap” in a Low Carbon Hydrogen Agreement (LCHA) does not incentivise developers to take on additional offtakers when marginal cost is lower than hydrogen revenue, thus preventing scale development in the hydrogen market.
3. There are currently no incentives for large-scale renewables developers to explore opportunities for monetising their excess power instead of simply receiving constraint payments when being asked to curtail production.

Discussion & Recommendation:

To establish a liquid hydrogen market, which inherently reduces volume risk for developers, having hydrogen midstream infrastructure is crucial. According to the modelling outputs, a hydrogen backbone is required for all net-zero scenarios, even for those with minimal domestic hydrogen demand. Thus, some of these investments can be considered as "low-regret" and should be prioritised.

Additionally, according to modelling results, offshore wind is set to produce 72% to 77% of Scotland’s power in 2045. Appropriate commercial models and lease criteria are needed to promote offshore wind system integration. Potential solutions could include power-to-X criterias in offshore wind leases, as well as a sliding scale incentive in constraint payments. This will not only promote the development of large-scale hydrogen production, but also reduce system operability costs, TNUoS charges, and renewable levies. This will ultimately strengthen both the commercial case and deliverability of offshore wind projects thus attracting the capital needed to realise the opportunity set out in this study.

Modelling Result
Key Takeaways

Modelling Results - Key Takeaways

The estimated levelised cost of hydrogen produced in Scotland for export to Europe ranges from **£1.8/kg to £2.2/kg in 2045**, depending on the cost of offshore wind production. Thus, **a competitive offshore wind industry is key** for Scotland to compete with other hydrogen-producing regions such as North Africa, which is expected to deliver hydrogen at £2/kg in 2045.

In all modelled scenarios, the value of Scotland's hydrogen and electricity export to the rest of GB and Europe is significant, reaching **~£12bn to £15bn/year in 2045.**

To enable this opportunity, a significant **buildout of both electricity and hydrogen transmission infrastructure is needed**. This buildout is similar across all modelled scenarios and sensitivities; thus, most investments can be qualified as **"low-regret".**

Most of the buildout of electricity and hydrogen transmission infrastructure is **needed by 2035. Investment in this infrastructure is needed today** to increase developers' confidence and avoid delaying energy generation investments.

A **hydrogen storage capacity of 14 GW** could bring significant advantages to the Scottish hydrogen export industry. It would help reduce the required hydrogen production and transport infrastructure, resulting in system-wide capital savings of at least **£700m by 2050**. This would improve the commercial value proposition for European buyers, as well as increase the overall system resiliency in Great Britain.

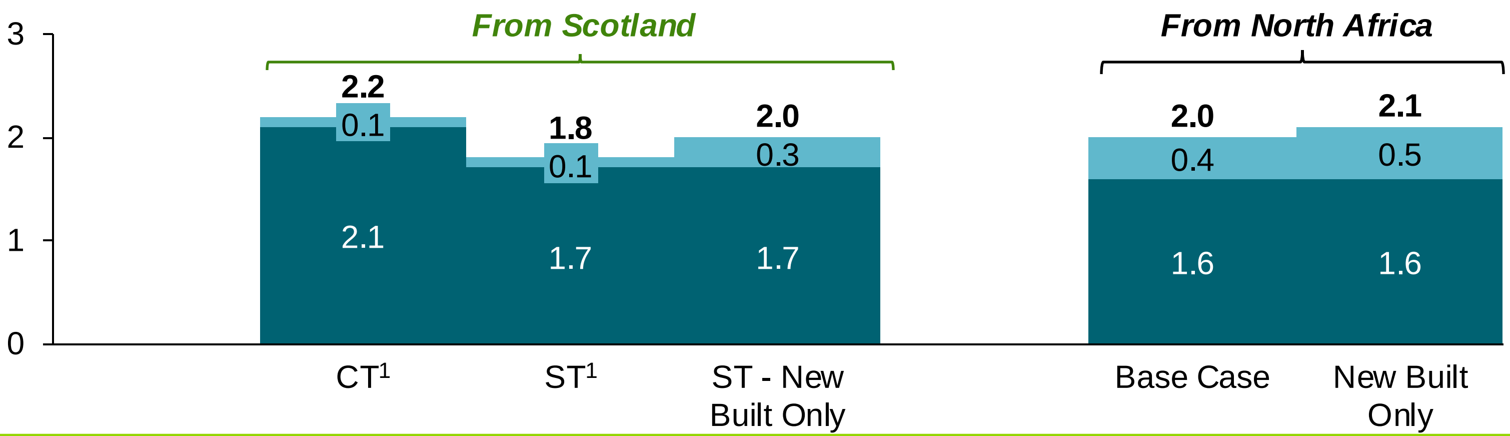
Most hydrogen produced in Scotland is only competitive with other regions when its offshore wind industry is strong

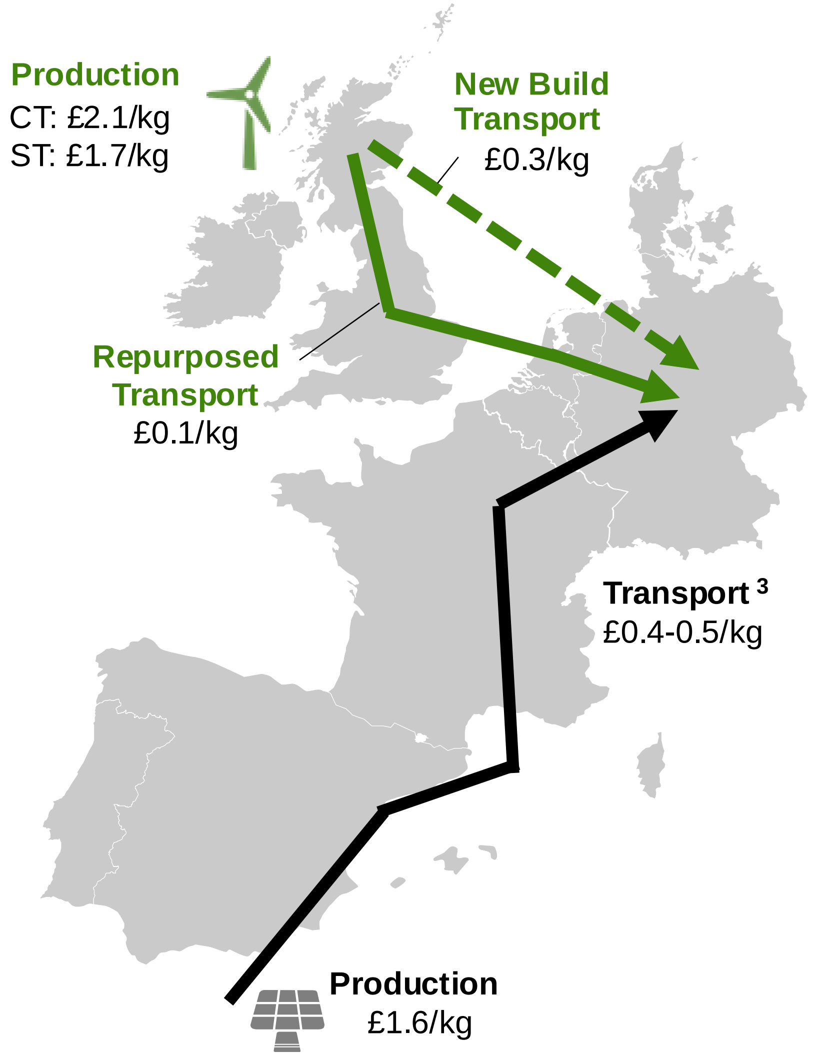
Key Messages

- The levelised cost of hydrogen (LCOH) in Scotland in 2045 is **£1.7/kg in the System Transformation (ST)** scenario[1] and jumps to **£2.1/kg in Consumer Transformation (CT)[1],** due to the **assumed higher offshore wind costs in the CT scenario**, highlighting the importance of developing a competitive offshore wind industry.
- By comparison, North African hydrogen is estimated to be produced at **£1.6/kg** in 2045 [2].
- However, the cost to transport Scottish hydrogen to Germany is estimated to be **£0.1/kg,** compared to **£0.4/kg** from North Africa.
- The difference in transport cost is due to the shorter distances as well as the ability to **repurpose existing gas pipelines** between the UK and Germany. If repurposing is not an option, transport costs from Scotland increase to **£0.3/kg**, which is still less expensive than the North African route.

Average LCOH delivered to Germany in 2045, £/kg H_2

Production Transport





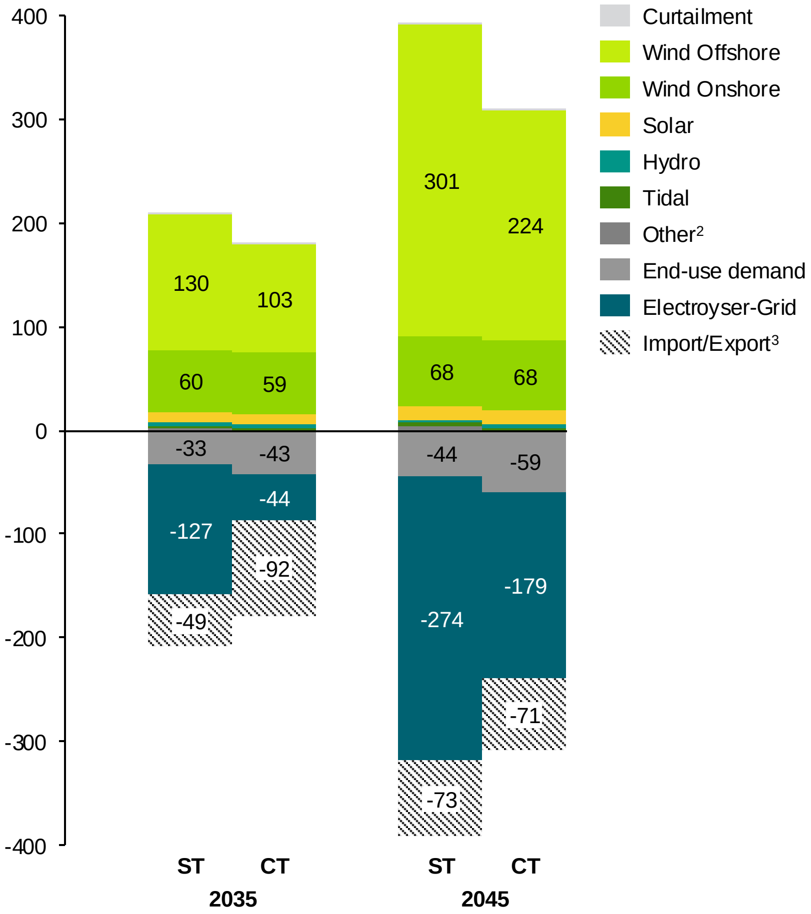
[1]CT and ST refer to the ESO Future Energy Scenario Consumer Transformation and System Transformation scenarios respectively. [2]ENTSO-E & ENTSOG (2022). TYNDP 2022 Scenario Building Guidelines. [3]Majority of the route is repurposed and transport cost between North Africa and Spain is embedded in the cost of production – therefore the transport cost represented is from Spain to Germany

Scotland's hydrogen and electricity export opportunity is significant, reaching ~£12 to £15bn/year[1] in 2045, and will grow post 2050

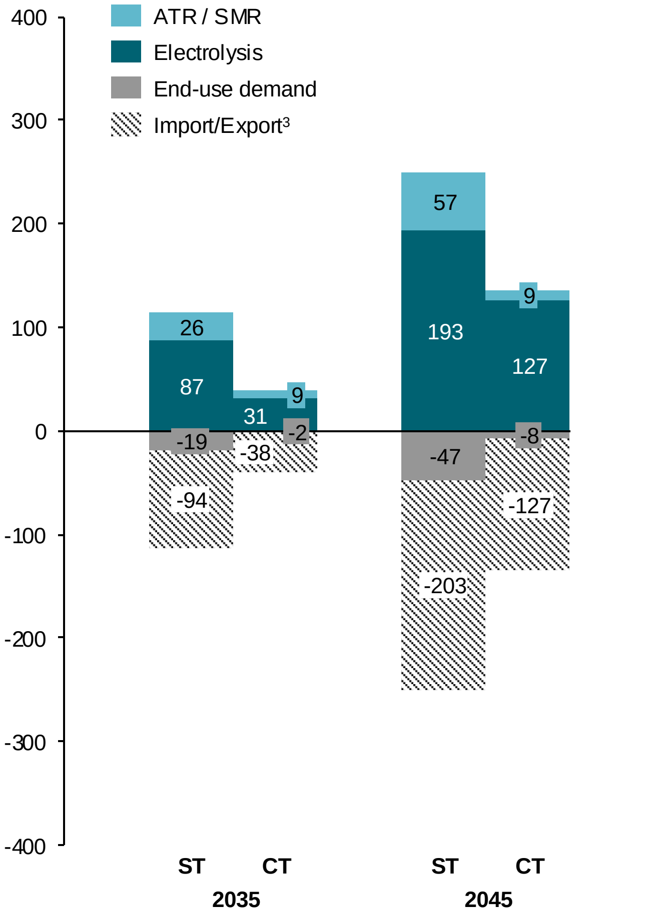
Key Messages

- In both scenarios, Scotland rapidly becomes a **large net exporter** of hydrogen and electricity due to the large volumes of electricity produced by expected offshore wind generation.
- **In 2035**, large volumes of **electricity are exported** across both scenarios, with up to **6x more than today** for the CT scenario.
- **Post 2035**, electrolyser costs decrease, and capacities scale up. Most of the excess electricity is used for the **production and export of green hydrogen,** as visible in the 2045 export figures.
- In both scenarios, **offshore wind** becomes and remains, from 2035, the **largest source of power supply** for Scotland, producing enough electricity to meet current Scottish power demand **8x over.**

Electricity Supply, TWh_{elec}



Hydrogen Export/Import[3], TWh_{H_2}



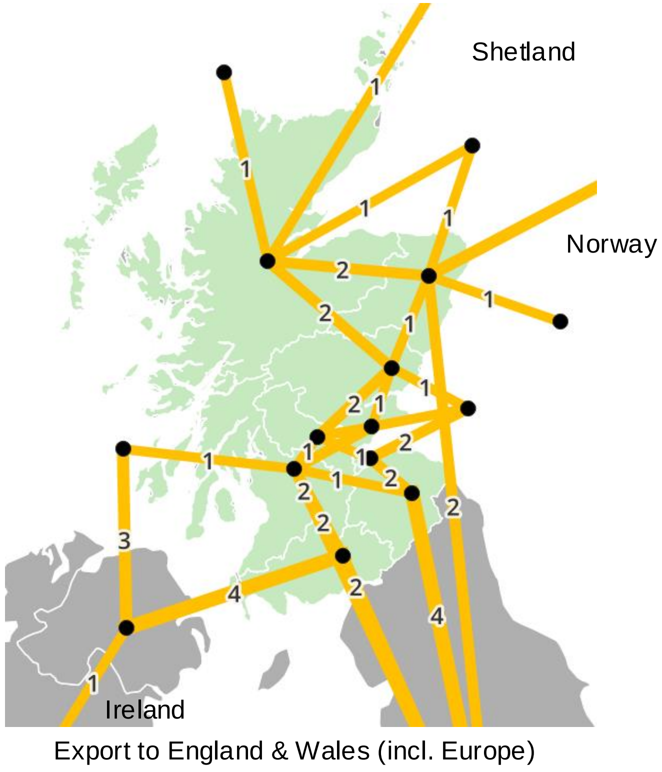
Scotland Annual Net Energy Exports, TWh

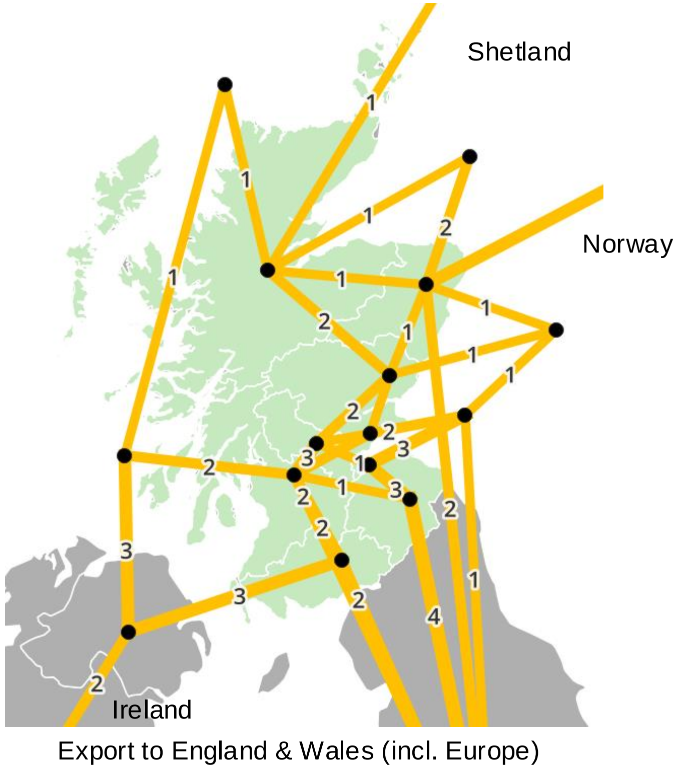
	2035		2045	
	ST	CT	ST	CT
Electricity	49	92	73	71
Hydrogen	94	38	203	127

[1]*High-level estimate based on LCOH mentioned on slide 24 and £50/MWh for electricity.* [2]*Contains residual renewable and non-renewable energy supplies.*[3]*Import/Export' refers to net importing energy when the value is positive, and net exporting energy when the value is negative.*

Similarities in electricity transmission network development across both scenarios highlight the low-regret nature of infrastructure investments

Electricity transmission infrastructure capacities between modelled nodes (GW)





2045 – System Transformation

Despite being a hydrogen-focused scenario, the 2045 grid development is similar to CT.

2045 - Consumer Transformation

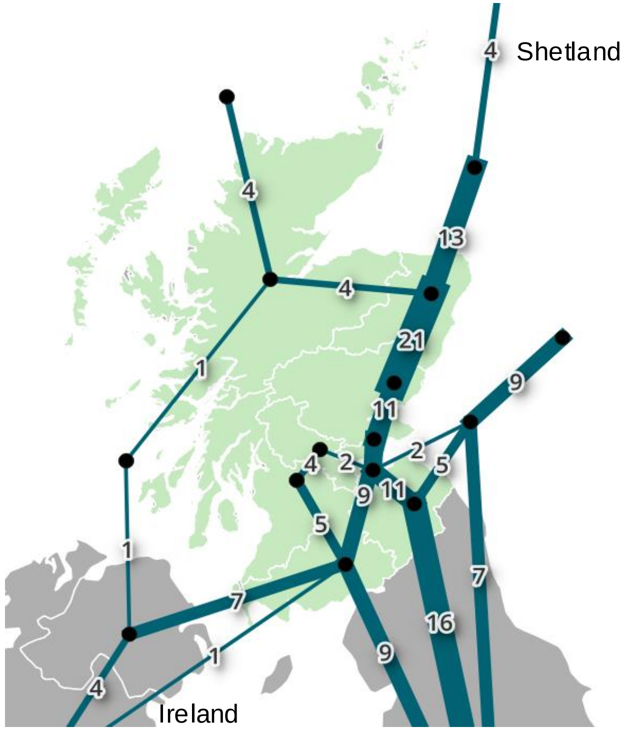
The grid development in CT is marginally higher than in ST.

Key Messages

- **Both scenarios show a need for significant development in electricity transmission**. The scale and design of the network differs slightly depending on the main use of electricity between scenarios.
- In both scenarios, direct connections from the North of Scotland directly to England are being developed to make the best use of Great Britain's offshore wind resources.
- The main difference between the two scenarios is in the **capacity increase** of connections within Scotland, rather than export. This is due to the **larger indigenous electricity demand** in the Consumer Transformation scenario.

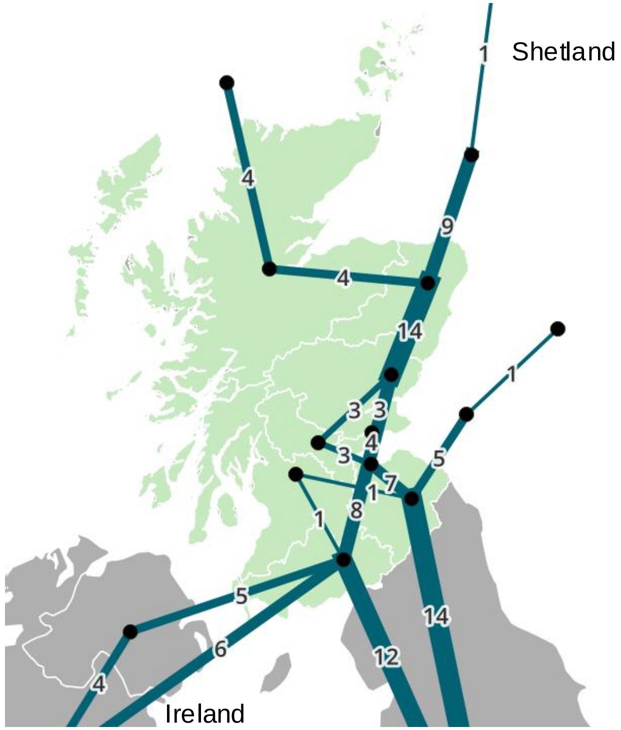
Investments in hydrogen transmission from Scotland to England and Europe are needed to enable exports in both modelled scenarios

Hydrogen transmission infrastructure capacities between modelled nodes (GW)



2045 – System Transformation

Big pipeline buildout from Scotland to EN&WS, exporting hydrogen via 3 routes



2045 – Consumer Transformation

Less buildout than in ST but still a lot of export to EN&WS via 2 routes

Key Messages

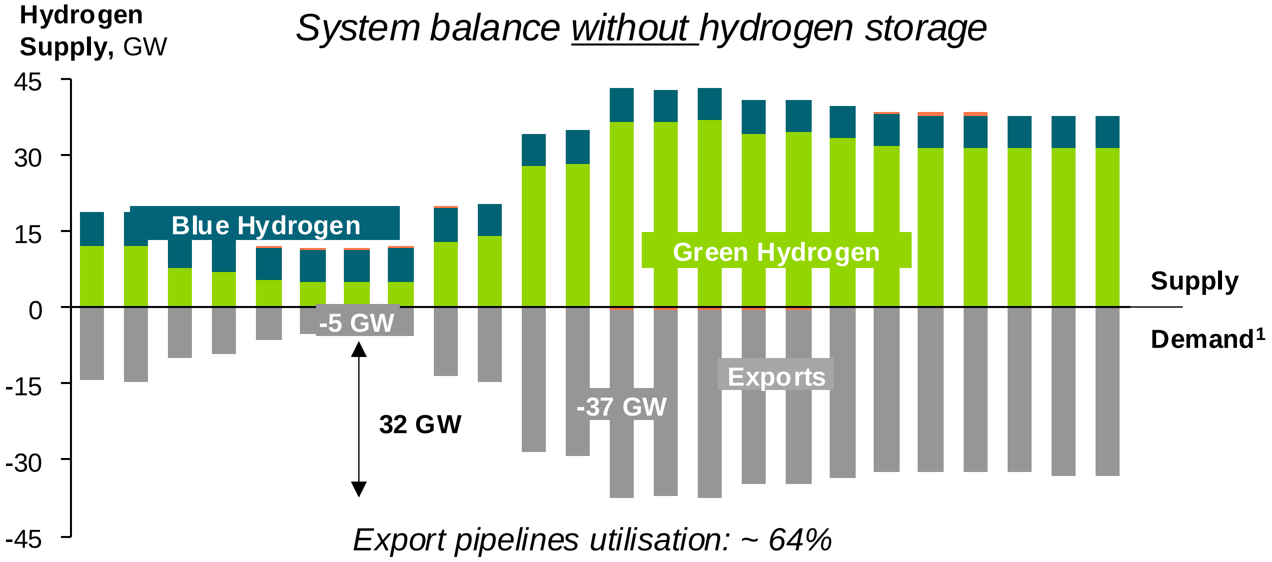
- Both scenarios demonstrate a **significant buildout** of hydrogen infrastructure across the country and for **exports**.
- **Hydrogen infrastructure buildout is more significant in ST**, as both endogenous and export demand are higher in this scenario.
- Most of the hydrogen infrastructure is developed alongside the **East Coast of Scotland** where most offshore wind, and thus electrolysers are located.
- Hydrogen pipeline interconnections to England and Ireland require large capacities. To reach this**, newly built hydrogen pipelines will be required**, independently of the ability to repurpose existing pipelines.

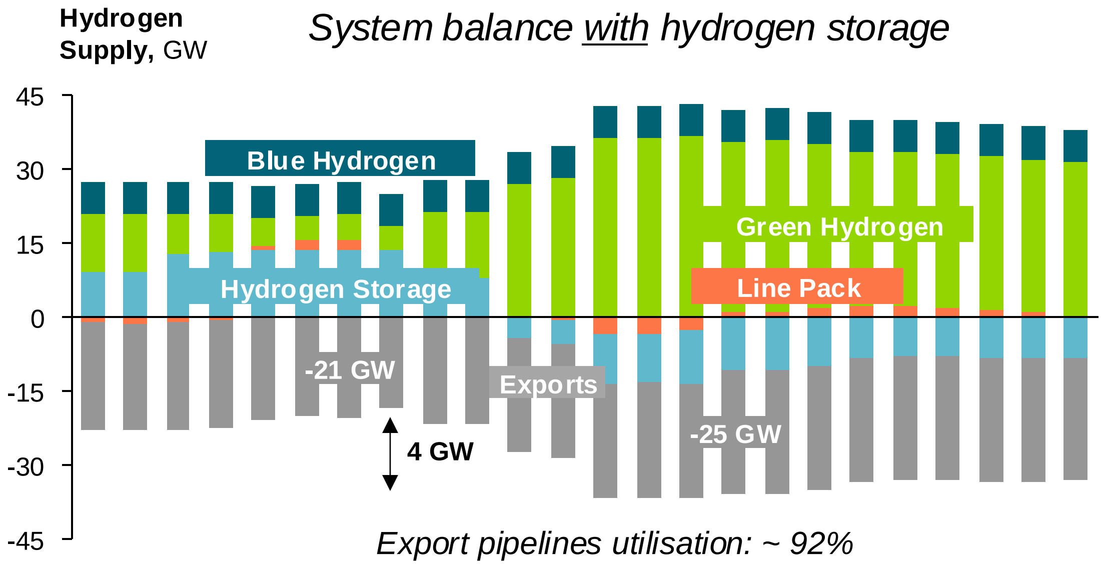
Developing hydrogen storage in Scotland can enable export pipeline sizing optimisation, and provide system resiliency on low wind days

Key Messages

- **Developing hydrogen storage in Scotland could be a challenge** due to a lack of salt caverns. However, considering alternative options, such as depleted Oil & Gas (O&G) fields, could provide significant benefits to Scotland, such as **greater hydrogen pipeline optimisation and system resiliency.**
- By storing a share of the green hydrogen production during periods with high wind output, hydrogen storage in Scotland can help optimise pipeline utilisation and **reduce the total required hydrogen infrastructure capacity by 28 GW** (18% of the total), thus **lowering the levelized cost of hydrogen by £0.1/kg H_2.**
- During limited wind days, ~**14 GW** of hydrogen storage provides system resiliency and enables Scotland **to keep exporting rather than relying on imports.**

Normal Spring Day (2045) System Transformation results





[1]Does not include end-user demand (industry, residential, etc.).

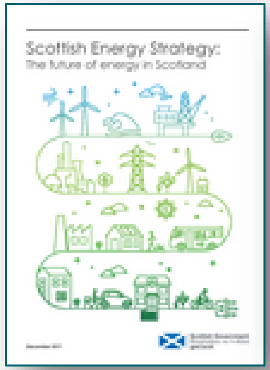
Introduction

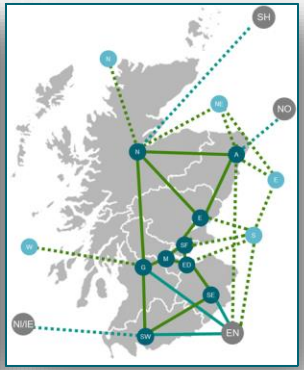
Unlocking the full potential of Scotland's clean energy opportunity through gas and electricity systems' integration and collaboration

The clean energy opportunity in Scotland is large but requires strong collaboration and coordination to be transformed into reality.

Whole system planning and integration have the potential to position the country as a leader in green industrialisation, as well as a key energy exporter to the rest of GB and Europe.

This project will demonstrate the benefits of collaboration between power and gas systems and provide pathways for achieving these benefits.





Modelling output combined with extensive stakeholder engagement will support policy and regulatory dialogue that would **involve and benefit Scotland's Key Energy Sector Stakeholders and help unlock the full potential of Scotland's clean energy opportunity.**

The potential of Scottish clean energy opportunity is explored with integrated capacity expansion modelling

General Model Configuration

- This study will use Guidehouse's Low Carbon Pathway (LCP) model to simulate the **evolution of the Scottish electricity and gas system from 2030 to 2050 in different scenarios.**

Configuration to Scotland Whole Systems Study

18x Geographic Scope:

- 9x onshore nodes
- 5x offshore nodes
- 4x neighbouring region

5x Model Years:

2030, 2035, 2040, 2045, and 2050

6x Rep. day:

Spring Summer Falll Winter Winter Peak Winter Peak & No wind

2x Scenarios:

Net-Zero FES 2023:
-Consumer Transformation (CT)
-System Transformation (ST)

Up to 4x Sensitivities:

TBD

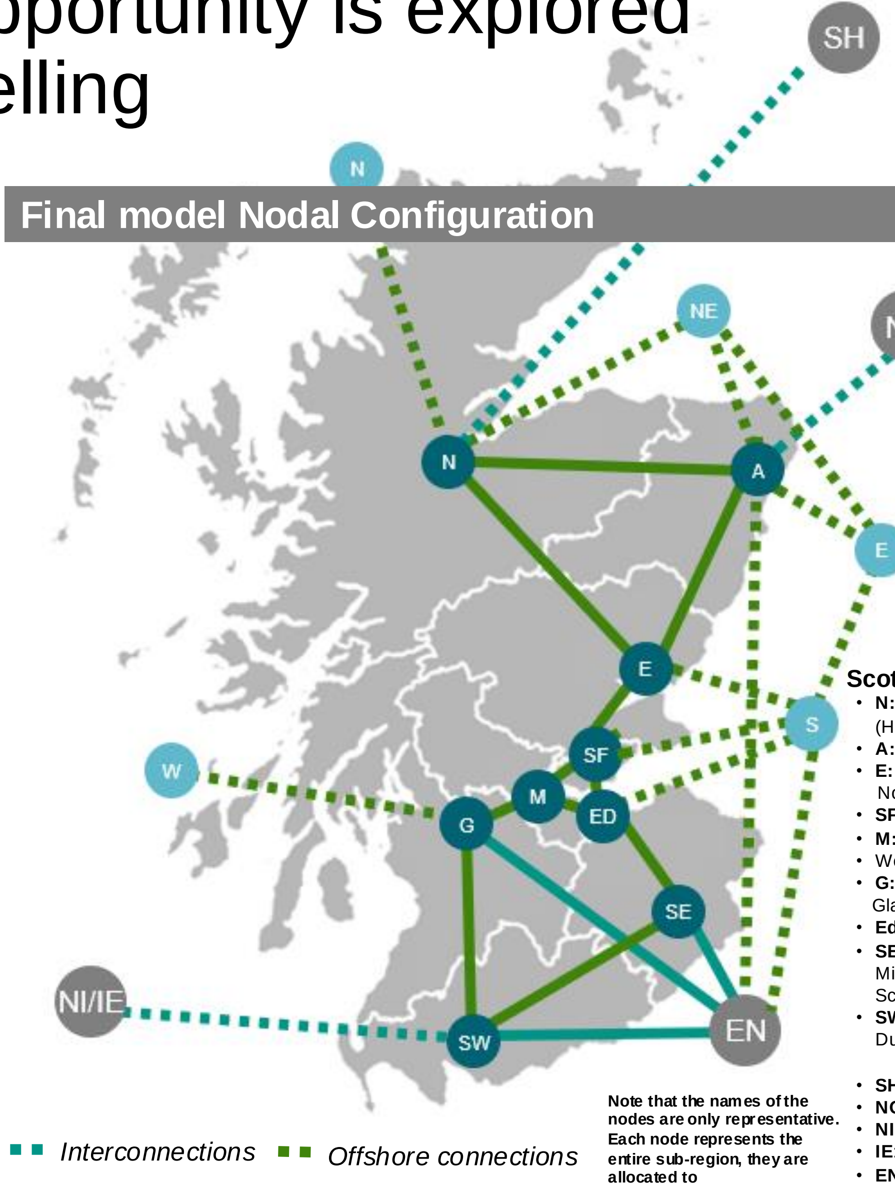
3x Energy Carrier:

Electricity
Hydrogen
Methane

24x Timestep:

Representative days
Hourly profiles

Final model Nodal Configuration



Note that the names of the nodes are only representative. Each node represents the entire sub-region, they are allocated to

Scotland regions:

- **N:** North Scotland (Highland, Moray)
- **A:** Aberdeenshire
- **E:** East – Angus, Perth, North Fife
- **SF:** South Fife
- **M:** Middle – Stirling,
- West Lothian and Falkirk
- **G:** Glasgow - Greater Glasgow and West coast
- **Ed**: Edinburgh
- **SE**: Scotland Southeast – Midlothian and east Lothian, Scottish borders
- **SW:** Scotland Southwest – Dumfries and Galloway

- **SH**: Shetland
- **NO**: Norway
- **NI**: Northern Ireland
- **IE**: Ireland
- **EN:** England

Two scenarios, based on FES 2023, are investigated to provide a range of future Scottish energy system developments

Scenario Description

The two scenarios investigated UK's energy system are based on FES 2023 scenarios:

Consumer Transformation (CT)

- Electrified heating
- Consumers willing to change behaviour
- High energy efficiency
- Demand side flexibility

System Transformation (ST)

- Hydrogen for heating
- Consumers less inclined to change behaviour
- Lower energy efficiency
- Supply side flexibility

Data for model regions outside of the UK are based on ENTSOE[1] – Ten Year Network Development Plan (TYNDP) scenarios[2]:

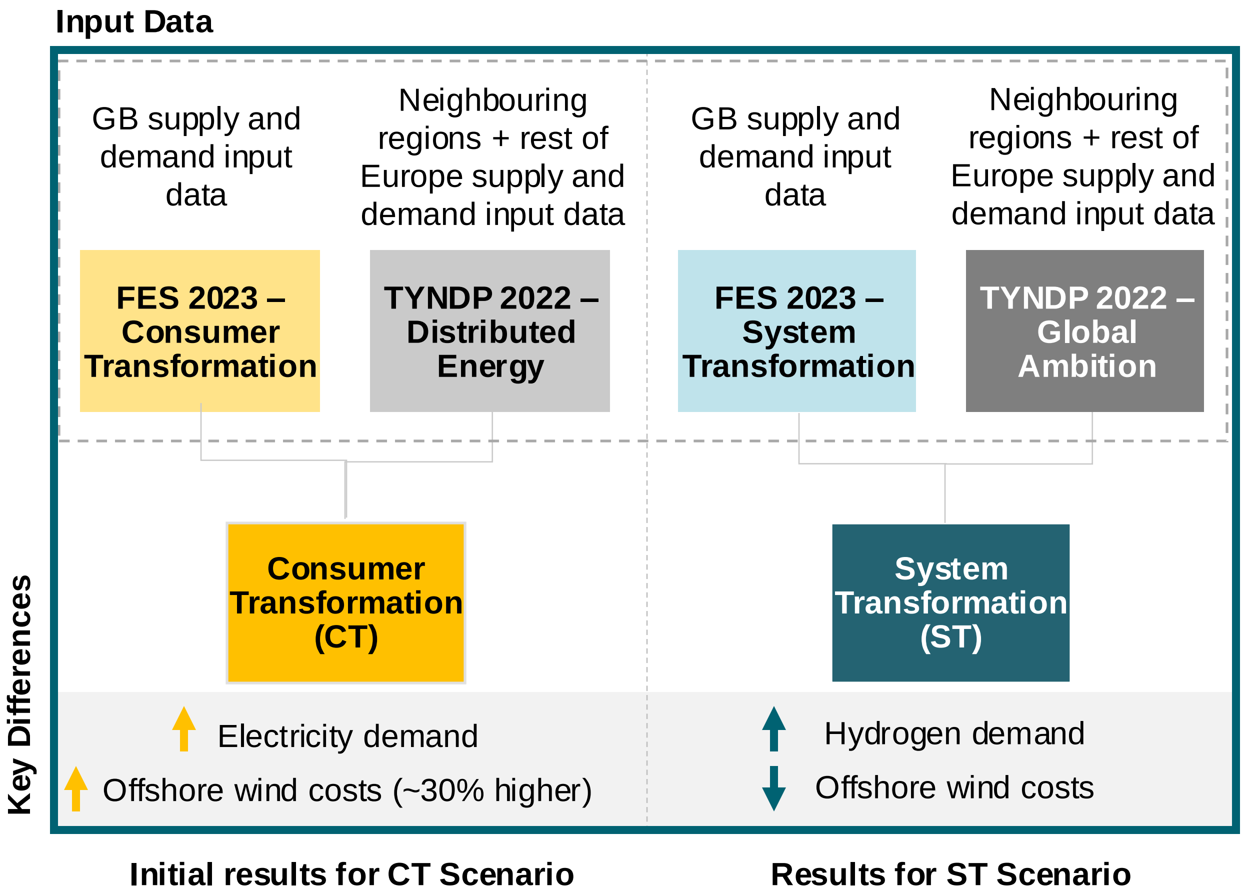
Distributed Energy:

- Focuses on decentralised technologies
- Reduces energy demand through consumer behaviour

Global Ambition:

- Focuses on large-scale technologies
- Priority on decarbonisation of energy supply

Scenario Framework



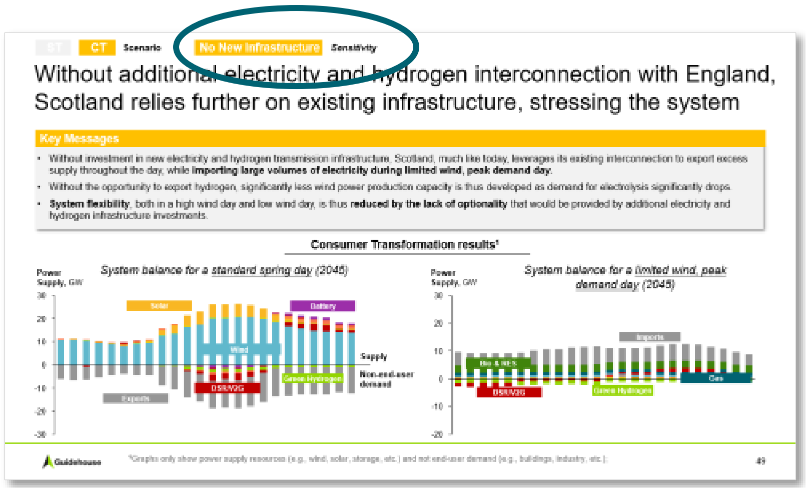
[1]ENTSOE – European Network of Transmission System Operators for Electricity [2]ENTSO-E & ENTSOG (2022). TYNDP 2022.

The following sensitivities have been selected to test the model and provide further insights into Scotland's energy system development

	Sensitivity Name	Description	Justification
1	**No new infrastructure**	Assessing the impact of not allowing Scotland to build out new infrastructure for export/import of electricity and hydrogen. This includes any infrastructure that does not exist (not in construction) **Baseline Scenario: Consumer Transformation, System Transformation** **Rationale:** Demonstrate Scotland's utilisation of its existing electricity infrastructure and development of infrastructure within Scotland, analysing the change of limited wind day profile	• **Driver:** Export/import of hydrogen & electricity is limited • **Model configuration:** Not allowing the model to build new infrastructure for electricity and hydrogen, setting both to 0
2	**High renewable deployment in neighbouring regions**	Assessing the impact that higher renewable deployment in neighbouring regions (Europe) will have on Scottish electricity and hydrogen exports, as well as its own energy system **Baseline Scenario: Consumer Transformation** **Rationale:** How competitive would Scottish hydrogen be against neighbouring regions if the upper bound on renewable buildout is higher in the rest of Europe?	• **Driver:** Effect on elec and H_2 export from Scotland • **Model configuration:** Increase in maximum renewable capacity of all countries in the rest of Europe by 20%
3	**New build only (no repurposed H_2 pipelines)**	Assessing the impact that no repurposed hydrogen pipelines (only new hydrogen infrastructure can be built) would have on hydrogen production and particularly export opportunities in Scotland **Baseline Scenario: System Transformation** **Rationale:** In the base scenarios, the export potential is maximised largely using repurposed pipelines, due to this option being the cheapest, but do exports remain high with only new pipelines?	• **Driver:** Buildout of new export routes & effect on H_2 export • **Model configuration:** Future repurposing of existing infrastructure is disallowed (set to 0) for both Scotland & Europe
4	**Deployment of hydrogen storage in Scotland**	Assessing the impact that the possibility of having offshore hydrogen storage available would have on the supply-demand balances in the Scottish energy system and hydrogen infrastructure **Baseline Scenario: System Transformation** **Rationale:** Scotland has a large offshore depleted O&G field that could host hydrogen storage	• **Driver:** Potential for offshore hydrogen storage in Scotland • **Model configuration:** Allow storage to be built

Selected sensitivities are used throughout the report, to test the model and provide readers with further insights into the Scottish energy system

	Sensitivity Name	Label	The way in which it is used	How it is referenced in the report
1	**No New Infrastructure**	**No New Infrastructure**	• CT: Investigate the behavior of electricity system during days with peak demand and limited wind • ST: Analyse electricity curtailment and its correlation with the deployment of green hydrogen electrolysers and exports	**All slides including sensitivities results are referenced this way**
2	**High renewable deployment in neighbouring regions**	**EU Renewables +20%**	• CT: Analyse the impact on electricity exports and infrastructure buildout • CT: Provide an overview of the impact on hydrogen exports	
3	**New Build Only (no repurposed H_2 pipelines)**	**New Build Only**	• ST: Analyse the behavior of the hydrogen system and particularly the impact this would have on hydrogen exports and infrastructure buildout • ST: Provide insight into the change in the transport cost of Scottish hydrogen to Europe and its competitiveness against other import routes	
4	**Deployment of hydrogen storage in Scotland**	**H_2 Storage**	• ST: Analyse the behavior of the hydrogen system during days with peak demand and limited wind • ST: Provide insight into how the presence of storage would optimise the infrastructure buildout through the balancing of the system	



Methodology and approach

Study Context and FES

This study aims to develop an objective and analysis-based view of the evolution of Scotland's electricity and gas systems towards a more integrated, net-zero energy system by 2050. To do this, our methodology applies a regional and whole-system modelling approach.

Project Context

- National Gas Transmission and SGN commissioned a study to create **an objective and analysis-based vision** of a whole energy system that addresses the interactions and complexities of an integrated electricity and gas energy system.

Why a "whole system" approach?

- A whole system modelling approach recognises that analysing the electricity and gas systems in isolation is not sufficient, nor appropriate. This is particularly important in the context of the electricity and gas systems becoming increasingly interdependent in the pathway to net zero.

  For example, electricity networks will have to be sized and will have to account for generation capacity fully or partially dedicated to the production of hydrogen. At the same time, gas networks will have to be repurposed to accommodate increasing volumes of hydrogen flowing through the network as well as the use of hydrogen in power generation.

What are the benefits of a "whole system" study?

- Implementing a whole system approach will highlight key areas where increased interaction between electricity and gas infrastructure will be required and where changes to regulation, market frameworks and system operator practices may deliver value to consumers.
- To perform a whole system study, it is crucially important that Electricity Networks and Government are engaged, involved, and heard in the project. This ensures the results hold for the entire energy system and provide a realistic, consistent view on how the energy system will evolve towards a net zero 2050.

Connection to FES

- The work performed by ESO on its Future Energy Scenarios (FES) acts as a foundation for this analysis by serving as its basisfor future scenarios of energy demand.
- FES's net-zero scenarios – System Transformation (ST), Consumer Transformation (CT) and Leading the Way (LW) – provide three different, but plausible visions of future electricity, hydrogen, and methane demand and supply. FES analyses these three scenarios from a broadly top-down GB-level perspective of supply and demand rather than on a full and explicit bottom-up regional basis. It also assumes an unconstrained network so as not to bias downstream network development activities.
- In this study, we use two of the FES scenarios (Consumer Transformation and System Transformation), disaggregating energy demand across 9 Scottish onshore regions. **This regionalisation approach is described in Section 2.** We then apply a whole system approach to explore implications on the buildout and localisation of electricity and gas resources, as well as implications on the buildout and operation of electricity and gas transmission infrastructure.
- We have decided to model the ST and CT scenarios as they provides two very different, opposite views of the future Scottish energy system. This allows us to gather insights from the differences, but more importantly, the similarities between the two scenarios. On the other hand, the LW scenario is not comparable, and did not provide many insights during the past. Thus, to increase project efficiency and reduce efforts, we are only modelling ST and CT, with any more ambitious net-zero scenario potentially considered as a sensitivity.
- This analysis does not adopt all the views of the FES on future electricity and gas supply. However, on occasion, it adopts certain supply assumptions that are tightly aligned with the spirit of each FES scenario. **These exceptions are also described in Section 2.**

Analysis Considerations and Limitations

- This reports presents a large set of detailed assumptions and inputs that will be used to model the Scottish electricity and gas system. While this study aims to adequately simulate the operation and evolution of Scottish's electricity and gas systems the results of this analysis are not intended to dictate when and where supply and transmission infrastructure investments may take place.
- The results of this study will be purely **reflective of an economic, cost-optimisation exercise**, and does not reflect specific technical, operational and locational (spatial) constraints of GB's electricity and gas system. Investments in supply and transmission infrastructure are, naturally, contingent on energy policy, regulation and strategy. Future findings from this study should be read in this context and should take into consideration limitations of the analysis.

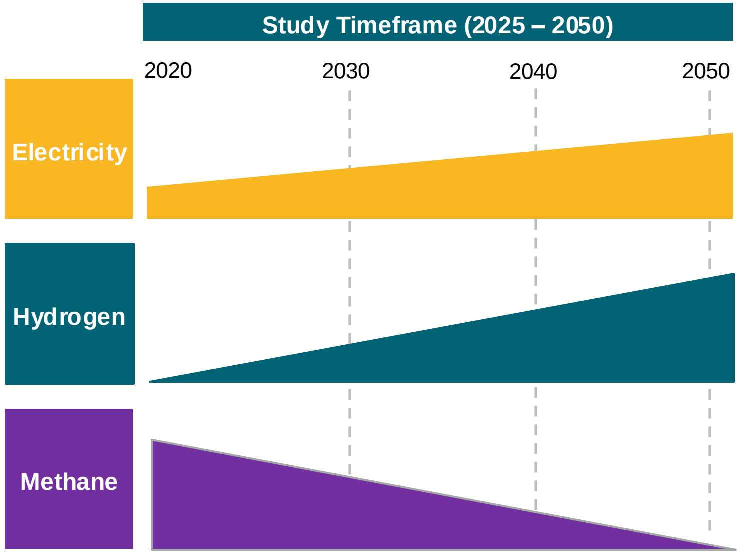
Scenario development

For energy demand, we adopt the FES net-zero demand scenarios and disaggregate their energy demand across Scotland's regions. For supply and infrastructure, we define key assumptions to ensure the model optimisation results align with reality.

Energy Demand

We disaggregate electricity, hydrogen, and methane demand from the two FES net-zero scenarios across each of Scotland's 9 regions.

- **Electricity:** We determine the regional distribution of electricity demand using GSP[1] -level FES results to separate Scotland's data from the UK – and apply that distribution to the total electricity demand across the two scenarios
- **Hydrogen**: We apply a sector-specific approach, using FES and other secondary resources, to disaggregate hydrogen demand across regions.
- **Methane**: We disaggregate methane demand across regions using historical, regional gas demand by LDZ[2] and apply it to the FES forecast for each scenario



9 Scottish regions

1. GSP = Grid Supply Point.
2. LDZ = Local Distribution Zone

Energy Supply and Infrastructure

- Energy supply resources and infrastructure options include electricity and gas supply resources like offshore and onshore wind, solar, nuclear, or electrolysers, as well as infrastructure options like on/offshore hydrogen and electricity transmission infrastructure.
- In some cases, our approach is to align with assumptions from the FES and, thus, adopt exogenous inputs into our analysis. While for others, our approach is to remain agnostic and endogenously model those technologies / options / decisions.

Offshore Wind	Hydrogen Supply	Hydrogen Network	Offshore Trans. Network
Other Renewables	Electro -lysers	Hydrogen Storage	Dispatchable Generation
Nuclear	Green Gas	Electricity Interconnections	Electricity Storage

Electricity demand regionalisation approach

We determine the regional distribution of electricity demand using GSP-level FES results to separate Scotland's data from the UK – and apply that distribution to the total electricity demand across two scenarios

BUILDINGS

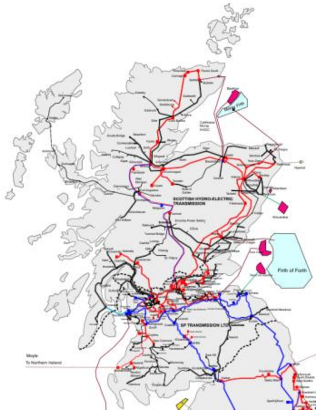
INDUSTRY

TRANSPORT

Note: As part of the ENA's DFES initiative, the FES reports electricity demand and embedded generation at the GSP-level for each scenario. This data is referred to as the "building blocks" of electricity demand. GSP-level data does not capture total customer demand. It reflects the net impact of embedded generation and excludes transmission-connected loads and demand from the rail. T&D losses are also excluded.

- We first aggregate GSP-level electricity demand and embedded generation to each of the 9 regions (e.g., GSP #1, 2, 3, 4, etc. are mapped to North Scotland, GSP #5, 6 and 7 are mapped to Edinburgh, GSP #8, 9, 10 and 11 are mapped to Greater Glasgow, etc.).
- Demand from GSP points in Scotland is compared to all GSP demand across GB to develop regional shares (%).
- We apply these regional shares to the total customer electricity demand (which includes transmission-connected load and rail). Important to note that electricity demand for electrolysers is excluded.

~160 GSPs



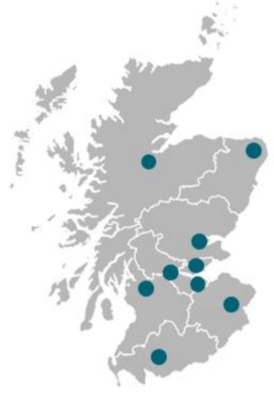
Considerations

- GSP data **nets off** embedded generation
- GSP data **excludes** Tx-connected demand
- GSP data **excludes** rail electricity demand
- GSP data **excludes** T&D losses[1]

Implied Assumptions

- Assume Tx-connected demand is **proportionally distributed** across regions.
- Assume rail electricity demand is **proportionally distributed** across regions.

9 Scottish regions



General Approach

End-User Demand by GSP (TWh) – by GSP

+

Embedded Generation (TWh) – by GSP

End-User Demand + Embedded Gen. (TWh) – by Scottish regions

Note: End-User demand and embedded generation accounts for c.95% of demand. This excludes transmission-connected loads and rail. To apportion these across all regions, we use the regional mix of end-user demand and embedded generation.

Share of Demand (%) – by GSP

×

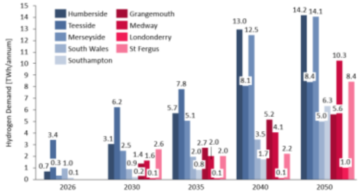
Total Customer Electricity Demand by Scenario(TWh) – by FES

Sources

- **ESO FES** (incl. building block data)

Hydrogen demand regionalisation approach

We apply a sector-specific approach, using FES and other secondary resources, to disaggregate hydrogen demand across regions.

		General Approach	Sources
BUILDINGS	• We apply regional shares based on heating equipment stock forecasts from the FES Regional Heating Model (with results available at the Local Authority level) aggregated up to individual regions.	Region's share of H_2 heating equipment (%) ✖ Building H_2 demand by scenario (TWh)	• **H_2 equipment shares**: FES Regional Heating Model • **H_2 Demand**: Results from each FES scenario
INDUSTRY	• We apply regional shares using the cluster demand data from the CCC UK industry report up to the total demand outlined in the report (73.3 TWh) • For FES scenarios with higher 2050 H_2 demand than the one outlined in the report, the remaining demand is distributed evenly across all regions. 	Region's share of H_2 demand (%) ✖ Industrial H_2 demand by scenario (TWh)	• **H_2 demand shares:** Element Energy, Net Zero Industrial Pathways (NZIP) model (Balanced Scenario) • **H_2 Demand**: Results from each FES scenario
TRANSPORT	• **Road**: We apply regional shares based on DfT historical statistics on licensed vehicles. • **Shipping**: We apply regional shares based on DfT historical statistics on freight tonnage traffic by port. • **Aviation**: We apply regional shares based on DfT historical statistics on air traffic passenger volume by airport. • **Rail** We apply regional shares based on ScotRail's data on the number of train stations	Region's share of transport sub-sector metric (%) ✖ Industrial H_2 demand by scenario (TWh)	• **Road transport:** Historical Vehicle Licensing Statistics. Department for Transport, (2023). • **Shipping**: Historical Freight tonnage traffic. Department for Transport, (2023). • **Aviation:** Historical Air Traffic at UK airports. Department for Transport, (2023). • **Rail**: ScotRail data on the number of train stations, (2019)

Methane demand regionalisation approach

We disaggregate methane demand across regions using historical, regional gas demand by LDZ and apply it to the FES forecast for each scenario.

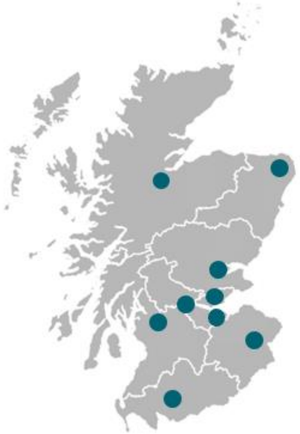
BUILDINGS

INDUSTRY

TRANSPORT

- We use historical (2012) subnational gas demand by regions shared by BEIS as they excluded gas used for power consumption and match the FES data for the reference year.
- We use these historical gas demand figures to develop regional shares (%).
- We apply these regional shares to the **2030-2050** methane customer demand figures (residential, industrial, commercial, transport)
- We then apply SGN's and NGT's data on the regions within Scotland to distribute the demand
- Biomethane production in Scotland is relatively small based on preliminary analysis and it seems to be used in rural areas, therefore injections in the transport infrastructure may not be feasible. When looking at the biomethane supply across the entire UK, the supply is heavy in W and SW, therefore making the proportion of Scottish supply negligible. It is proposed to avoid including biomethane demand in the model, as it is assumed biomethane will be consumed close to production and therefore, will not affect infrastructure needs between region. This assumption will assure infrastructure will not be created for transportation of negligible amounts.
- Map on the right is Biomethane Map 2021, produced by EBA. It shows that almost all of the existing projects are focused on England

9 Scottish regions



General Approach

Methane Demand by Region (TWh) — by BEIS

Regional share of Methane demand (%)

✖

Methane demand by scenario (TWh)

Methane Demand by Scottish Regions (TWh) — by SGN

Sources

- BEIS 2012 sub-national gas demand
- 2012 hourly gas demand by LDZ level (shared by SGN)

Low Carbon Pathways (LCP) Model

The LCP model is a capacity expansion and dispatch optimisation model used to identify the least-cost, energy system expansion pathways to meet future energy. Our LCP model has been adapted to the characteristics of Scotland's gas and electricity system and optimises across electricity, hydrogen and methane supply and transmission infrastructure.

Overall Approach

- This study uses Guidehouse's LCP model to simulate the decarbonisation, expansion, and hourly optimisation of the electricity and gas system from 2020 to 2050.
- The model is configured to a geographical scope made up of Scotland, its sub-regions, its neighbouring regions (England, Northern Ireland/Ireland, and Norway), and a simplified version of the remainder of Europe and models an integrated electricity, hydrogen, and methane system.
- The analysis models different scenarios of how electricity and gas supply and infrastructure can meet energy demand. This includes identifying what investments in electricity, hydrogen, and methane supply capacity and infrastructure will be required, where those investments will be needed, and when they will be needed.

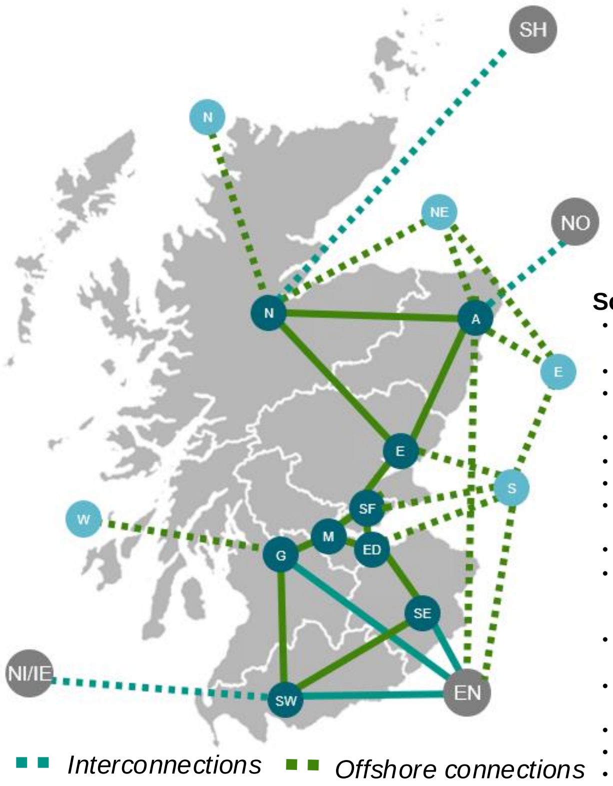
Modelling Configuration

- **Geographic Scope**: 9 Scottish onshore sub-regions + 5 offshore nodes + 1 Shetland node + 3 neighbouring regions + simplified remainder of Europe. The direct neighbouring regions include:
  - **England + Wales**
  - **Northern Ireland/Ireland**
  - **Norway**
- **Energy carriers**: Electricity, hydrogen and methane
- **Simulation timeframe**: 2030, 2035, 2040, 2045 & 2050
- **Intra-annual temporal resolution**: 6 representative days (4 seasonal days, a winter peak-day, and a winter supply/demand extreme)

Integrated Energy System Modelling

- The LCP model is an integrated capacity expansion and dispatch optimisation model used to identify the lowest-cost pathway to a decarbonised energy system.
- The analysis *solves* the expansion and decarbonisation of the electricity and gas (hydrogen and methane) system by investing in new supply and transmissions infrastructure over time (e.g., onshore wind, offshore wind, solar, electrolysers, hydrogen pipeline, transmission lines, etc.).
- As a "whole of system" model, the cross-sector energy conversion interactions between electricity, hydrogen and methane are an integral part of the analysis (e.g., electrolysers driving increased electricity demand, hydrogen gas turbines driving increased hydrogen demand)
- The analysis also models the use of transmission interconnections across regions (e.g., power lines and pipelines) and storage assets (e.g., gas and electricity storage) to balance supply and demand.
- The analysis's nodal configuration – whether sub-regions within the core geographical scope or with neighbouring regions – defines whether electricity and gas interconnections exist across regions.
- Each node is treated as a "copper plate" of demand and supply meaning there is no sub-nodal granularity of transmission or distribution infrastructure behind each node. In other words, the analysis focuses on the interaction of supply and transmission infrastructure across nodes and not within nodes.

Model Nodal Configuration



Note that the names of the nodes are only representative. Each node represents the entire sub-region, they are allocated to

Scotland regions:

- **N:** North Scotland (Highland, Moray)
- **A:** Aberdeenshire
- **E:** East – Angus, Perth, North Fife
- **SF:** South Fife
- **M:** Middle – Stirling, West Lothian and Falkirk
- **G:** Glasgow - Greater Glasgow and West coast
- **Ed**: Edinburgh
- **SE**: Scotland Southeast – Midlothian and east Lothian, Scottish borders
- **SW:** Scotland Southwest – Dumfries and Galloway
- **SH**: Shetland

- **NO**: Norway
- **NI**: Northern Ireland
- **IE**: Ireland
- **EN:** England

Modelling considerations and limitations

Results from this analysis are reflective of a modelling exercise and do not necessarily account for technical, operational and geospatial realities and complexities of the electricity and gas networks. This section describes a selection of limitations of this study's modelling approach which may have a material impact on results.

Modelling of Energy Supply & Demand

For all of Scotland's regions & England/Wales:

- Electricity, hydrogen and methane demand (2020, 2030, 2035, 2040, 2045 and 2050) are defined exogenously based on the Consumer Transformation and System Transformation FES scenarios and not optimised as part of the analysis.
  Note: The FES defines energy demand for GB, however, in this analysis, we have disaggregated demand across the model regions.
- This means, this study does not model self- and cross-price elasticities across energy carriers. In other words, by adopting pre-defined demand scenarios, our analysis does not model how energy carrier costs may impact their own demand, nor how the cost of one energy carrier may impact demand for another carrier. For example, lower costs for hydrogen vs. biomethane may encourage a shift towards hydrogen use by end-users. These supply-demand dynamics are not captured by our analysis because static, pre-defined demand scenarios are adopted.
- The rationale for adopting pre-defined scenarios of energy demand is to ensure consistency with ESO's FES scenarios.
- Ultimately, the objective of this analysis is not to identify the best and optimal scenario of energy demand through 2050, but rather to explore the development and operation of electricity and gas transmission infrastructure across a variety of scenarios.

Neighboring regions:

- Electricity, methane and hydrogen demand in the neighbouring regions are exogenously defined based on the 2022 TYNDP Global Ambition and Distributed Energy scenarios. We do not explicitly model supply-demand elasticity dynamics in any of the neighbouring regions given that we adopt pre-defined scenarios of 2020-2050 energy demand.
- Our analysis simulates electricity and gas interconnections between any of Scotland's regions and any of the neighbouring regions. We do not, however, model electricity and gas interconnections within the neighbouring regions. Rather, we model each individual neighbouring region as a "copper plate".

Spatial Dimensionality

- As described previously, this analysis applies a nodal configuration to model an energy system made up of 9 Scottish nodes, 5 offshore nodes and nodes in the rest of Europe. Each region is treated as a single node with supply and demand varying across the study timeframe.
  Note: The only exception is offshore nodes, which are only used to simulate supply and do not capture demand.
  By extension, this also means our analysis does not capture any sub-regional or spatial (locational) granularity within each of these nodes.
- The lack of further spatial dimensionality means that some technical and operational constraints are not and cannot be explicitly accounted for. For example, the geospatial layout of the electricity or gas distribution system within any of the 9 Scottish nodes is not explicitly modelled. This may mean technical constraints on electricity, methane and hydrogen supply and transport cannot be explicitly modelled.
- To mitigate the impact of these limitations, Guidehouse, SGN, and National Gas Transmission will work together to capture as much detail as realistically possible via alternative modelling levers and methods; for example, by imposing constraints and limitations on technically-unfeasible or technically-unlikely outcomes, in order to avoid unrealistic and questionable results.

Impact of Policy on Energy Infrastructure

- While this study aims to adequately simulate the operation and evolution of Scotland's electricity and gas systems the results of this analysis are not intended to dictate when and where supply and transmission infrastructure investments may take place.
- The results of our analysis will be purely reflective of a cost-optimisation modelling exercise and may not reflect the complexities and intricacies of interjurisdictional policy-making, security of supply and system/resource adequacy requirements, or other regulatory, technical and operational constraints. Findings from this study should be read in this context and should take into consideration limitations of the analysis.

Seasonal Representative Days

- Our analysis is configured to use an intra-annual temporal resolution based on six (6) representative 24-hour days. Four (4) of these representative days are seasonal days (e.g., winter, spring, summer and fall), the 5th day is a winter-peak day, and the 6th is a supply-demand extreme (intended to reflect a dunkelflaute).
- These representative days are used in lieu of modelling a complete 8760-hourly profile for a full year in order to achieve a balance of computational demand (and model runtime) with modelling accuracy.
- Each of these representative days capture hourly demand and supply profiles. Supply profiles for intermittent resources like wind, solar and hydro reflect real, hourly inter-daily variations and intermittency in their production profiles. Peak electricity demand days account for flexible supply which ensures the adaptability of the system, example is vehicle-to-grid (V2G) and demand-side response (DSR)
- The selection of intermittent production profiles can have a significant impact on results. For example, a poorly chosen wind profile can overestimate or underestimate wind production throughout the year. Similarly, a day with particularly drastic hour-to-hour variations in wind output can also yield skewed results.
- Guidehouse applies a rigorous analytical exercise for the selection of the intermittent production profiles underlying this study.

Electricity Infrastructure Approach

We define transmission capacities between Scotland's regions and interconnections with neighbouring regions using data from the Electricity Ten Year Statement (ETYS) 2022 and ENTSO-E's TYNDP 2022. The LCP model then optimises network expansion out to 2050.

Overall Approach

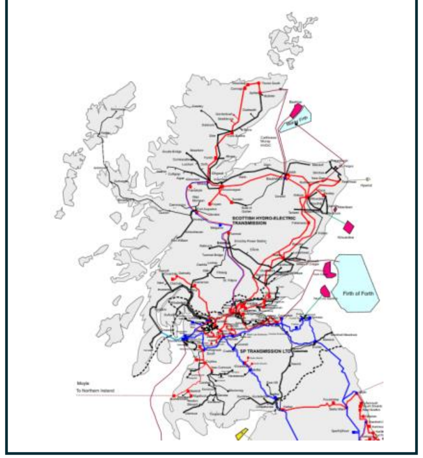
Electricity transmission within Scotland:

- We define existing electricity transmission infrastructure across Scottish regions based on ETYS 2022.
- To do this, we estimate and aggregate the capacities of individual transmission lines linking Scottish regions.

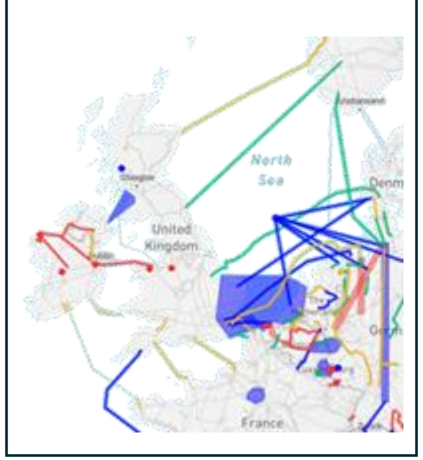
Electricity interconnections with neighbouring regions

- We define existing and planned electricity interconnections with neighbouring countries based on ENTSO-E's TYNDP 2022. Planned interconnections only reflect "planned" projects and not those "under consideration".
- Electricity transmission capacities between other countries is based on net transfer capacities specified in TYNDP 2022 DE/GA.

ESO ETYS 2022



ENTSO-E TYNDP 2022



Scotland regions:

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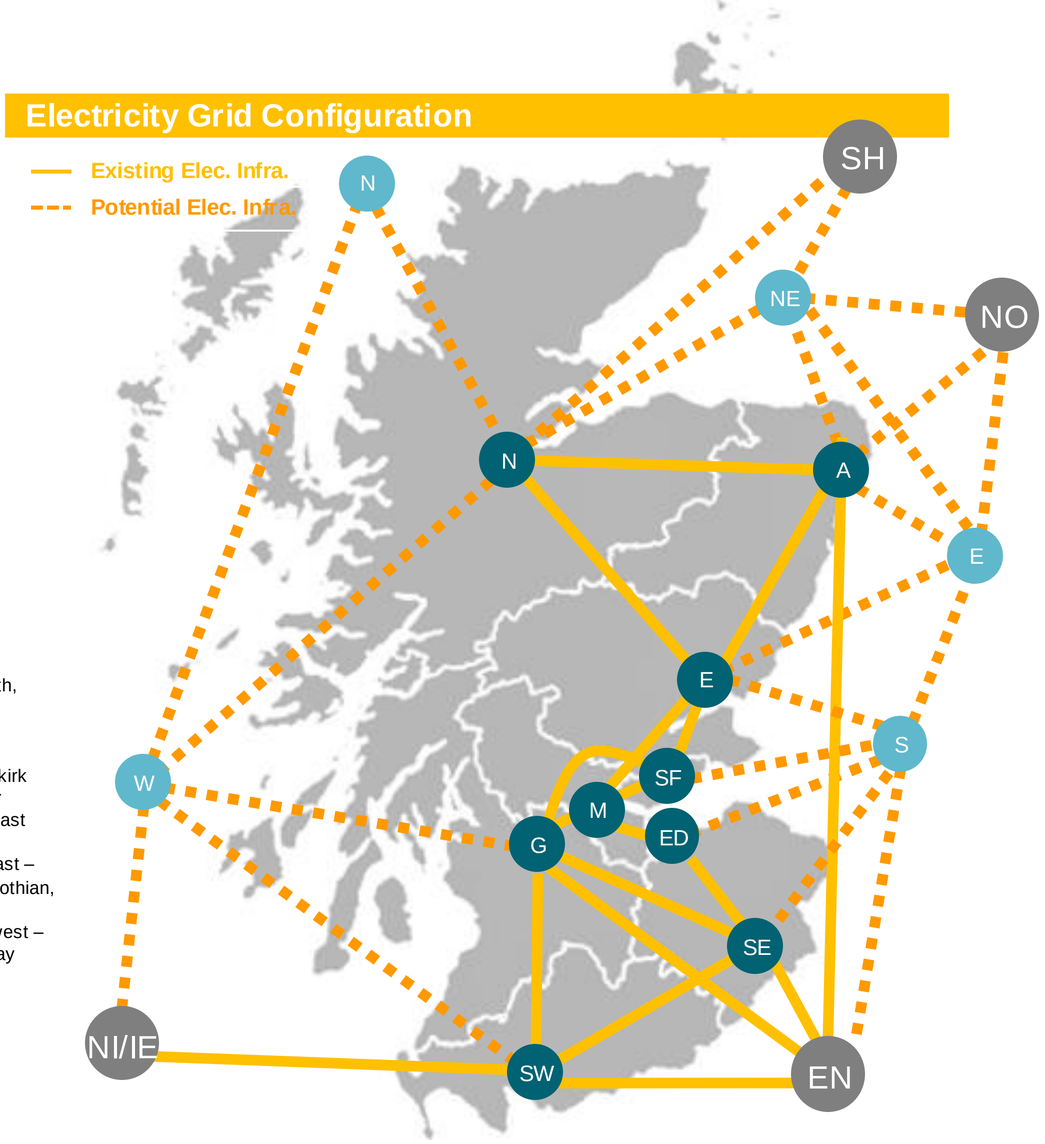
Electricity Grid Configuration



Hydrogen Infrastructure Approach

The model also calculates the expansion of hydrogen transmission capacity between Scotland's regions (onshore and offshore) and interconnections with neighbouring regions until 2050.

Overall Approach

For all model regions:

- Existing/Planned hydrogen transmission capacity between regions is assumed to be zero across all model years (2030,2035, 2040, 2045, and 2050).

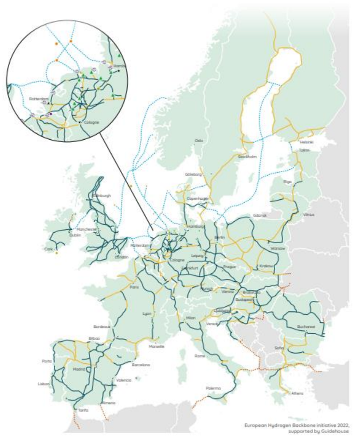
Hydrogen transmission within Scotland:

- The model has the option to build/optimise:
    - Onshore hydrogen transmission capacity between each bordering onshore region.
    - Offshore hydrogen transmission capacity between each offshore region and each bordering onshore region.
        - The ratio of onshore and offshore hydrogen transmission pipelines between onshore and offshore regions is based on the distribution of land vs. sea between the two midpoints of the zones

Hydrogen transmission outside of Scotland:

- The model can optimise hydrogen transmission capacity between Scotland and England, Ireland, NI, Norway, and Shetland for 2030, 2035, 2040, 2045, and 2050 based on the cost parameters specified in the slide: Techno-Economic input parameters | Infrastructure Options.
- For all other model regions, the model can optimise hydrogen transmission capacity between countries based on the hydrogen transmission connections provided in the EHB 2040 Map

EHB 2040 Map



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- **SH**: Shetland
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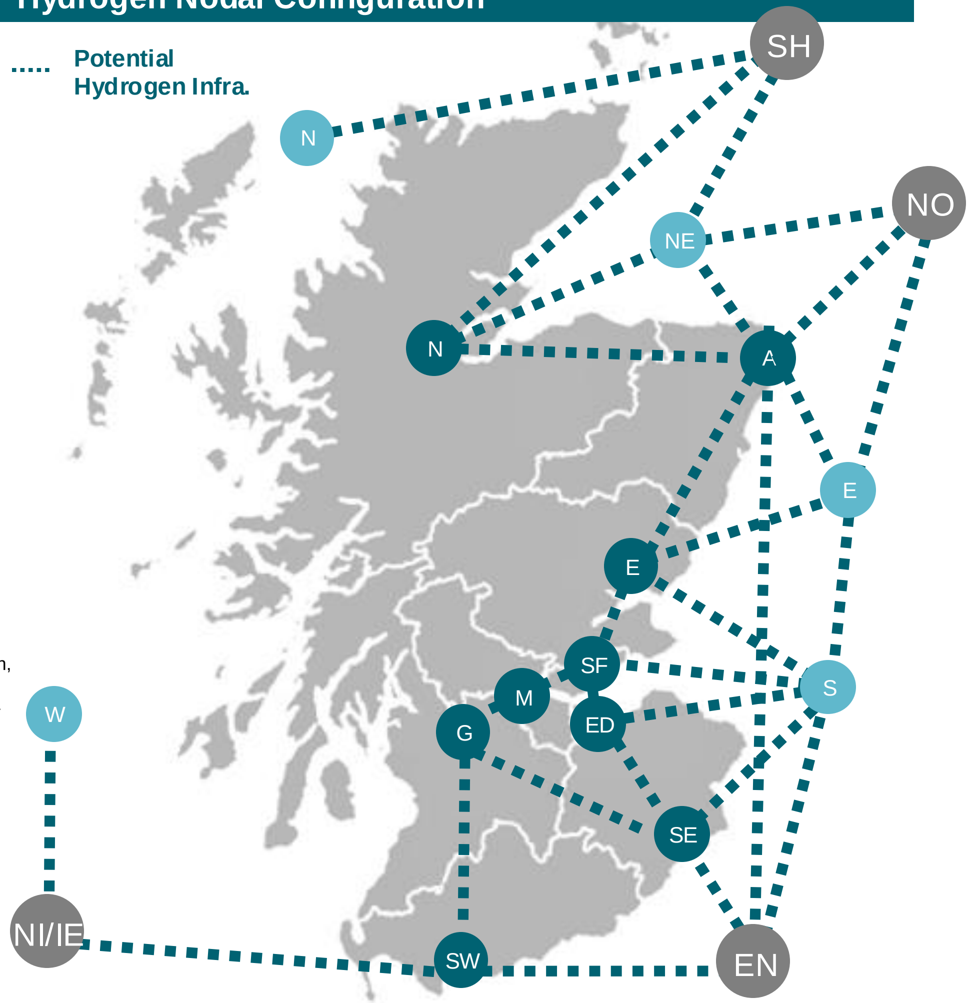
Hydrogen Nodal Configuration



Modelling Results

Scotland's Energy Export Opportunity

This section presents detailed modelling results from **Scotland's interactions with its neighbouring regions** under two different **whole energy system** scenarios and sensitivities:

System Transformation | **Consumer Transformation**

No New Infrastructure | **EU Renewables +20%** | **New Build Only** | H_2 Storage

What is covered:

- Cost-competitiveness of Scottish Hydrogen
- Theoretical Export Opportunities
- Realisable Export Opportunities
- Export Flow Schematics

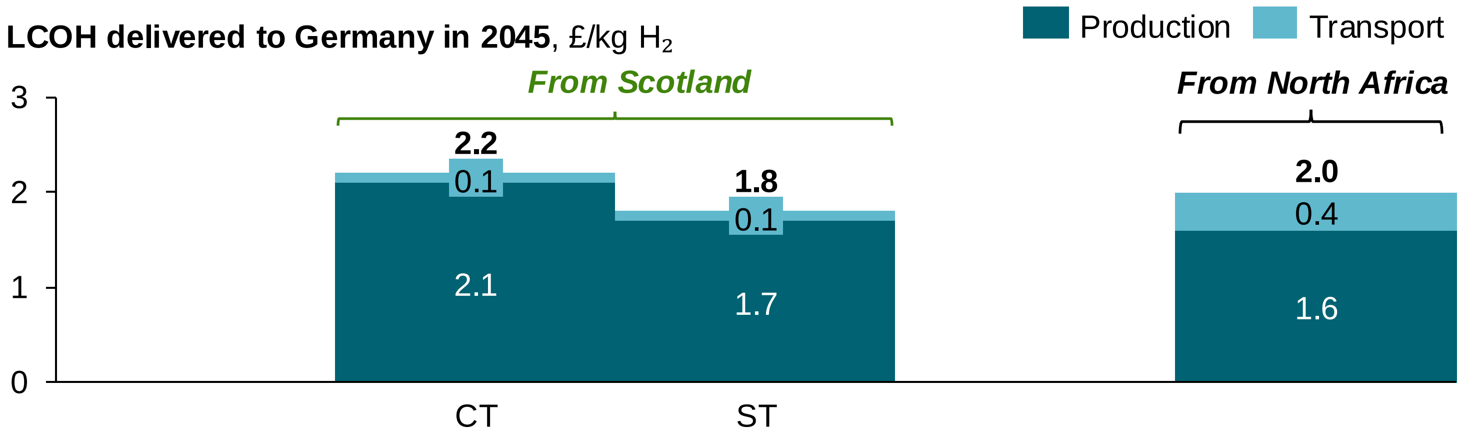
ST | CT | Scenario

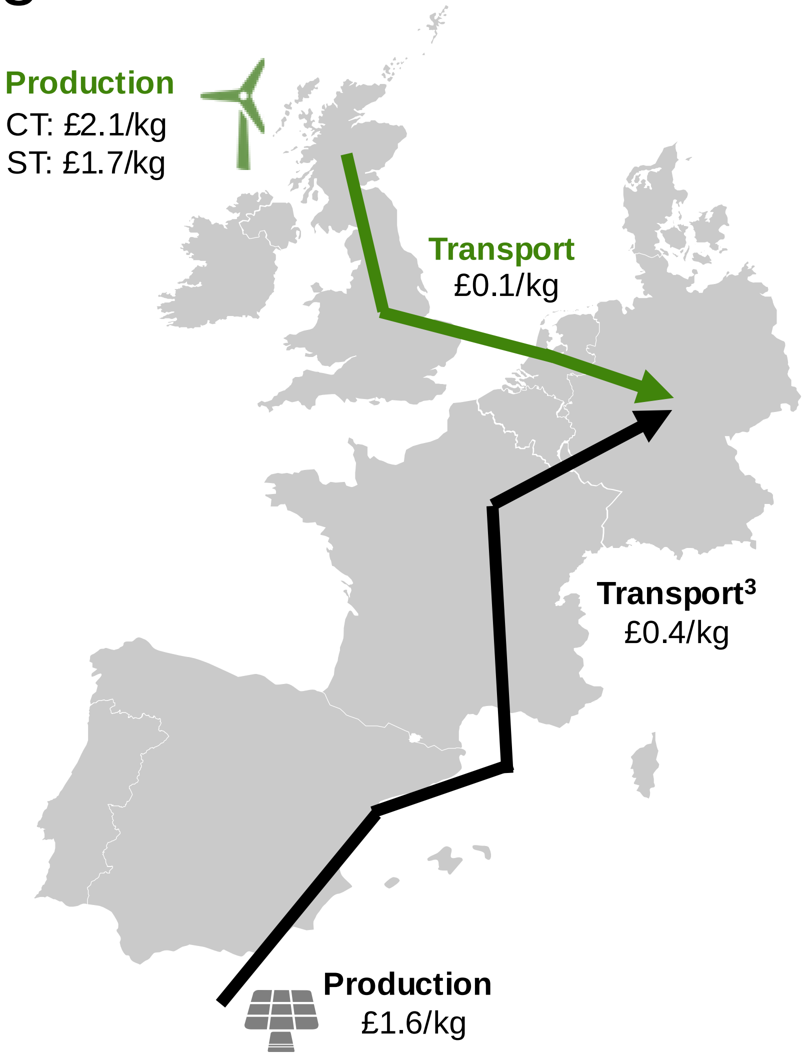
Offshore wind costs have a significant impact on the competitiveness of Scottish hydrogen exports relative to other regions

Key Messages

- The cost of producing green hydrogen in Scotland in 2045 is **£1.7/kg in the ST** scenario[1] and jumps to **£2.1/kg in CT [1],** due to the **higher offshore wind costs in CT**, highlighting the importance for Scotland to develop a competitive offshore wind industry.
- By comparison, North African-produced hydrogen is estimated to be produced at **£1.6/kg** in 2045 [2].
- However, the cost of transport for Scottish hydrogen to Germany would only cost **£0.1/kg** compared to **£0.4/kg** to transport North African hydrogen to Germany
- The difference in transport cost is due to the shorter distances as well as the ability to **repurpose hydrogen pipelines** between the UK and Germany.

LCOH delivered to Germany in 2045, £/kg H_2





[1]CT and ST refer to the ESO Future Energy Scenario Consumer Transformation and System Transformation scenarios respectively – please refer to slide 12 for more details. [2]ENTSO-E & ENTSOG (2022). TYNDP 2022 Scenario Building Guidelines. [3]Majority of the route is repurposed and transport cost between North Africa and Spain is embedded in the cost of production – therefore the transport cost represented is from Spain to Germany

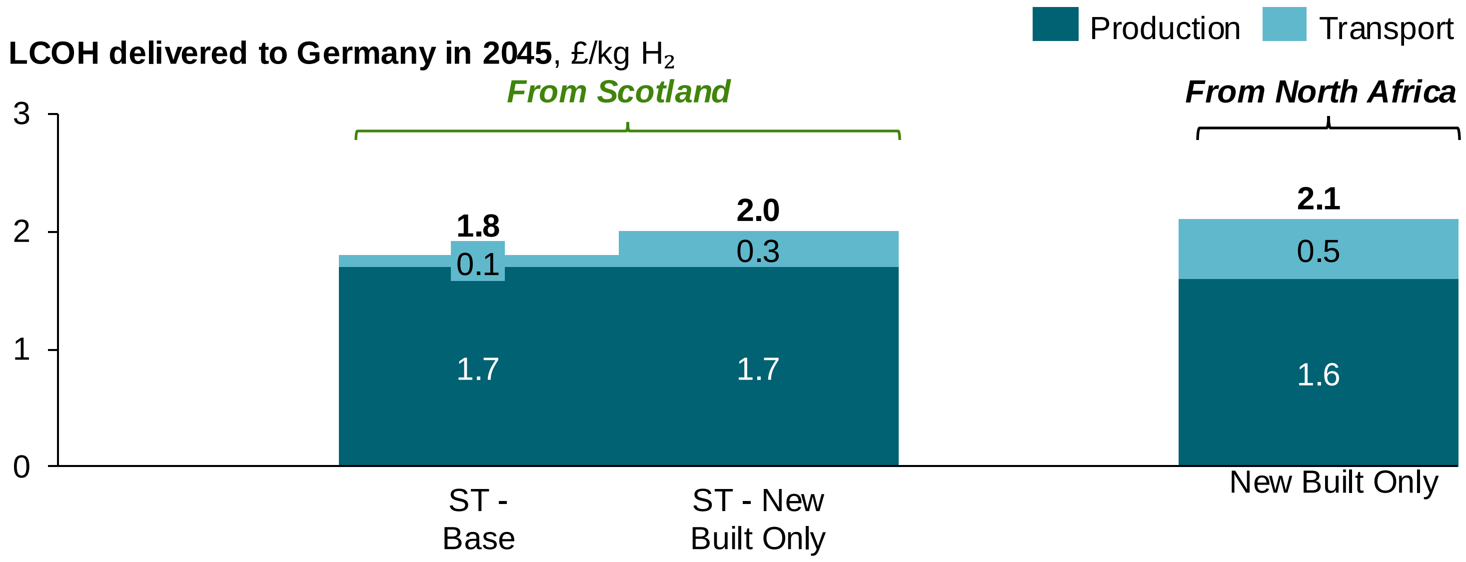
Guidehouse

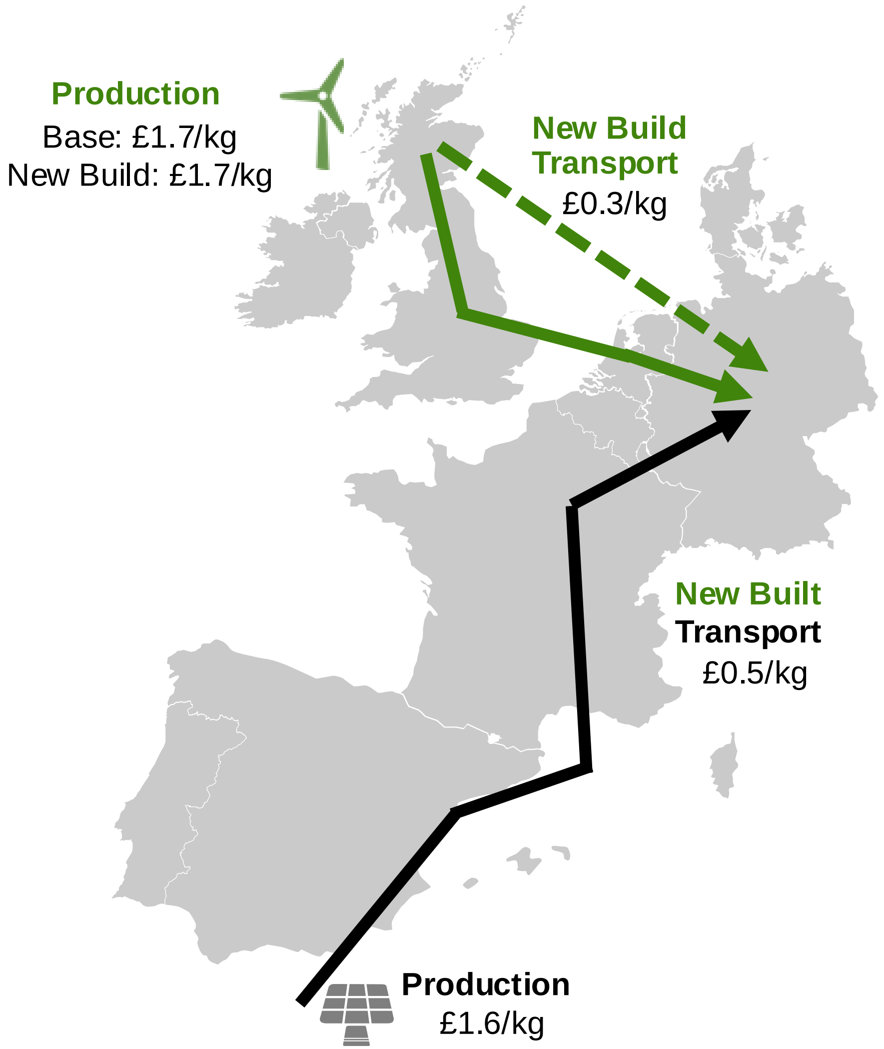
Repurposing of existing infrastructure helps to reduce the LCOH of Scottish hydrogen but is not critical to unlocking the export opportunity

Key Messages

- The cost of producing green hydrogen in Scotland and delivering it to Germany in 2045 is **£1.8/kg in the ST Base** scenario and jumps to **£2.0/kg in ST New Built Only** sensitivity**,** due to the higher costs associated with building new pipelines
- Indeed, in this case, it would cost **£0.3/kg** to transport Scottish hydrogen to Germany and **£0.5/kg** to transport North African hydrogen to Germany. The midstream cost for Scottish hydrogen remains lower, but the differential reduces.

LCOH delivered to Germany in 2045, £/kg H_2





ST CT Scenario

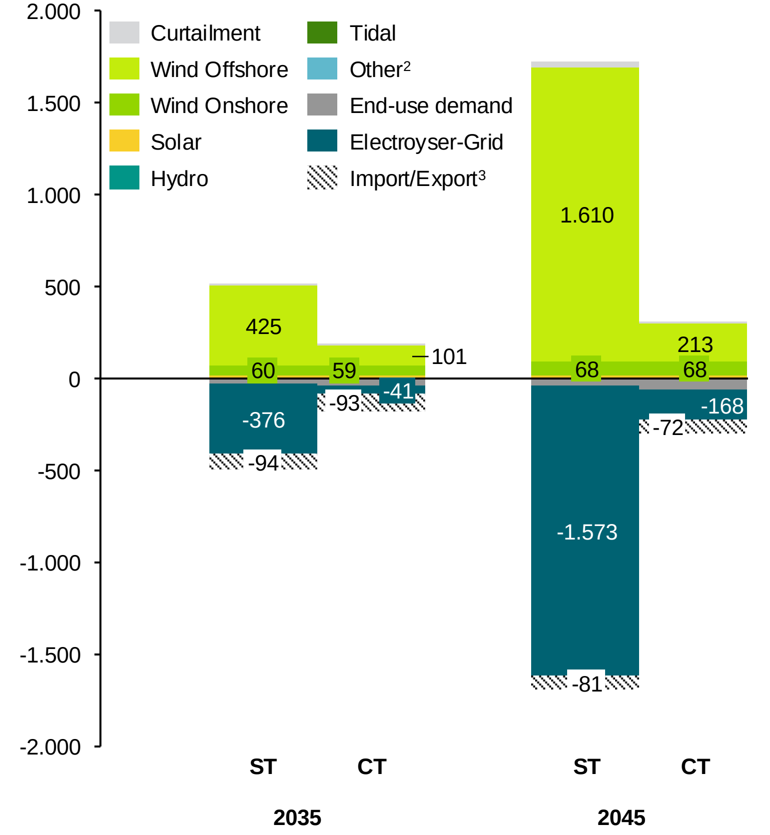
Theoretical Opportunity

Scotland's theoretical[1] potential for energy exports is enormous, particularly in a scenario where its offshore wind industry is competitive

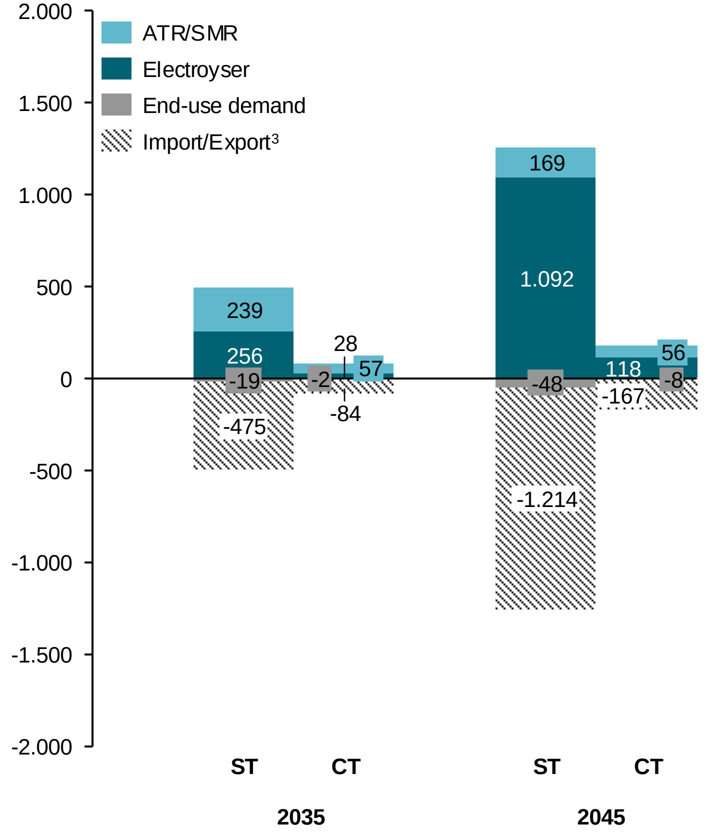
Key Messages

- In ST, across all modelled years, Scotland can become an **enormous net exporter[1]** of energy due to the scale of offshore wind's unconstrained capacity
- In contrast, assuming a higher levelized cost of energy and lower European hydrogen demand, Scotland becomes a more **moderate, but still significant, net exporter** in the CT scenario
- Offshore wind generation in Scotland produces over **1,000 TWh of green hydrogen in ST** and **100 TWh in CT** that is **exported to continental Europe.** This Scottish green hydrogen helps to satisfy European hydrogen demand cost-efficiently.
- To achieve this, **over 300 GW** of offshore wind is developed, highlighting the theoretical nature of unconstrained results which cannot be achieved in practice.

Electricity Supply, TWh_{elec}



Hydrogen Supply, TWh_{H_2}



Scotland Annual Net Energy Exports, TWh

	2035		2045	
	ST	CT	ST	CT
Electricity	94	93	81	72
Hydrogen	475	84	1,214	167

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[1]Based on a theoretical exercise where no constrain on how much offshore wind and hydrogen production capacity - please see next slides for clarification. [2]Contains residual renewable and non-renewable energy supplies.[3]Import/Export' refers to net importing energy when the value is positive, and net exporting energy when the value is negative.

However, there are real life implementation constraints that need to be considered such as capital deployment, skills, permitting challenges

To ensure the modelling reveals realistic results, the following additional constraints have been applied throughout this report across both scenarios and sensitivities:

Offshore Wind

- The offshore fixed-bottom and floating wind maximum installed capacities are based on the currently installed capacity and current offshore wind leases in Scotland. The wind leases set the 2040 upper bound per region.
- Post 2040, an upper bound of an additional 2.5 GW of offshore wind can be installed in each of the offshore regions per 5-year time frame.
- Values are always above Scottish Government targets (e.g., 11GW by 2030)

Offshore Wind Upper Bound (GW)					
	2030	2035	2040	2045	2050
Scotland	12.6	25.6	44.4	59.4	74.4

Blue hydrogen production

- Blue hydrogen maximum installed capacities for England/Wales and Scotland are based on the highest FES scenario (System Transformation). The blue hydrogen potential is assumed to be 25% in Scotland and 75% in the rest of GB.
- Blue hydrogen production in Scotland is constrained to the following model regions: Aberdeenshire (SCA), East (SCE), Middle (SCM), and South Fife (SCSF).

Blue Hydrogen Upper Bound (GW)					
	2030	2035	2040	2045	2050
Scotland	1.0	3.0	5.3	6.5	6.5
Rest GB	3.0	9.0	15.8	19.5	19.5

Green hydrogen production

- Green hydrogen maximum installed capacities for England/Wales and Scotland have been applied to ensure realistic installed electrolysers over time (see table below).
- Maximum value for 2030 has been set to be twice the Scottish Government target of 2.5GW – leaving the model with the opportunity to build all of the UK Government 5GW target in Scotland.
- A progressive exponential increase of upper bound is provided for the following years.

Electrolyser Upper Bound (GW)					
	2030	2035	2040	2045	2050
Scotland	5.0	12.5	22.5	37.5	62.5
Rest GB	5.0	12.5	22.5	37.5	62.5

ST CT Scenario

Realisable Opportunity

Scotland hydrogen and electricity export opportunity remains significant, reaching ~£12 to £15bn/year[1] in 2045, and will keep scaling post 2050

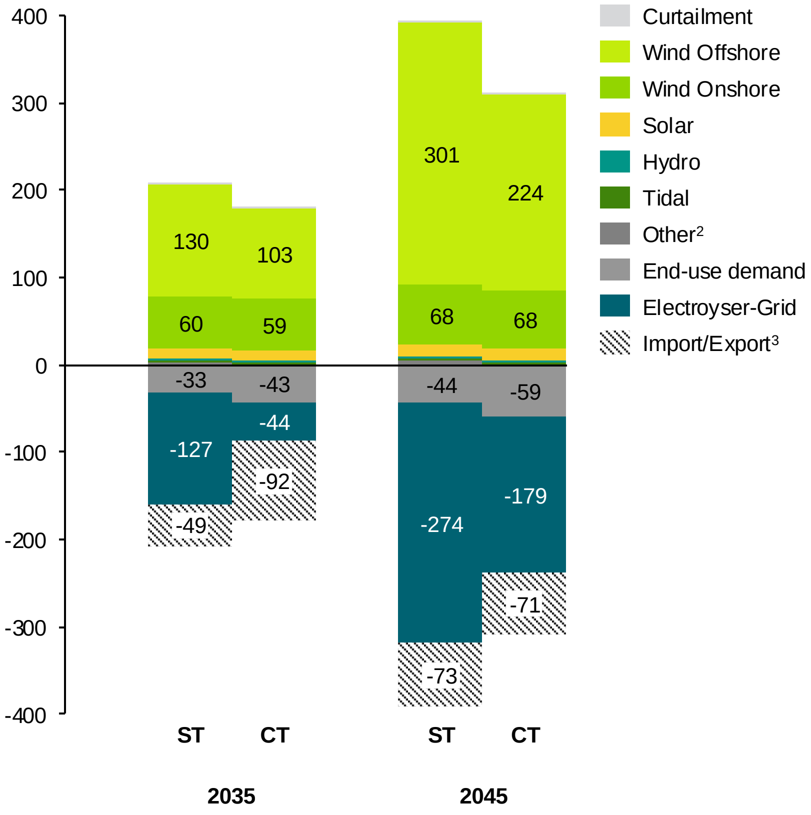
Key Messages

- In both scenarios, Scotland rapidly becomes a **large net exporter** of both hydrogen and electricity due to the large volumes of electricity produced by expected offshore and onshore wind generation.
- **In 2035**, large volumes of **electricity are exported** across both scenarios, with up to **6x more than today** for the CT scenario.
- **Post 2035**, as electrolysers become more cost-competitive and scale up, most of the excess electricity is used for the **production and export of hydrogen,** as visible from 2045 export figures.
- In both scenarios, **offshore wind** becomes and remains, from 2035, the **largest source of power supply** for Scotland, producing enough electricity to meet today's Scottish power demand **8x over.**

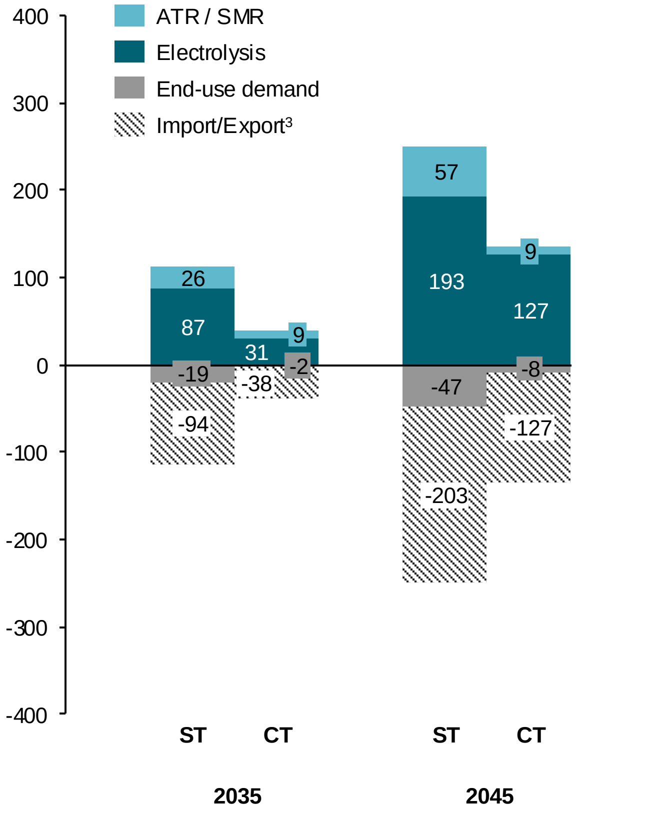
Scotland Annual Net Energy Exports, TWh

	2035		2045	
	ST	CT	ST	CT
Electricity	49	92	73	71
Hydrogen	94	38	203	127

Electricity Supply, TWh_{elec}



Hydrogen Export/Import, TWh_{H_2}



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[1]High-level estimate based on LCOH mentioned on slide 24 and £50/MWh for electricity. [2]Contains residual renewable and non-renewable energy supplies.[3]Import/Export' refers to net importing energy when the value is positive, and net exporting energy when the value is negative.

However, export volumes are sensitive to European renewables buildout in a scenario with higher offshore wind cost, such as CT

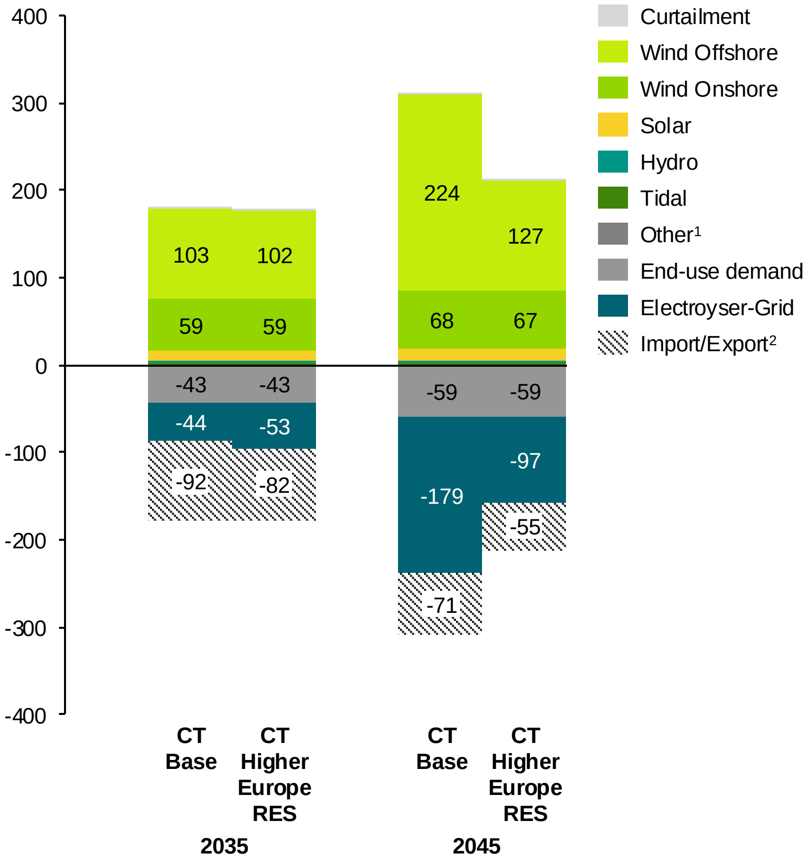
Key Messages

- **In CT, offshore wind supply decreased by 97 TWh** compared to the base case, but onshore wind supply remained nearly the same. The decrease in offshore wind is due to two main factors: less electricity exports and hydrogen exports (less electrolysis). The **onshore wind is cheaper** and therefore did not get impacted
- Electricity export **decreased by 16 TWh** in 2045
- Blue hydrogen supply did not get impacted in 2035 and **slightly decreased** in 2045, but green hydrogen **decreased significantly, by 59 TWh**
- Europe **prefers to produce more of its own green hydrogen** from the additional available **solar** and **onshore wind** capacity
- The LCOE of solar and onshore wind in many European regions is cost-competitive to floating offshore wind in Scotland

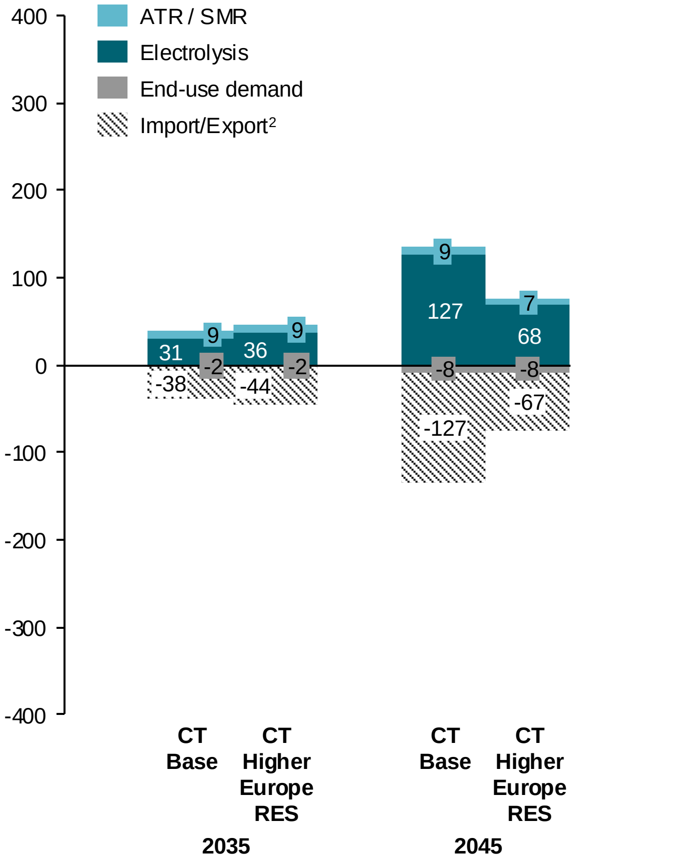
Scotland Annual Net Energy Exports, TWh

	2035		2045	
	CT (Base)	CT (Higher EU RES)	CT (Base)	CT (Higher EU RES)
Electricity	92	82	71	55
Hydrogen	38	44	127	67

Electricity Supply, TWh_{elec}



Hydrogen Export/Import, TWh_{H_2}



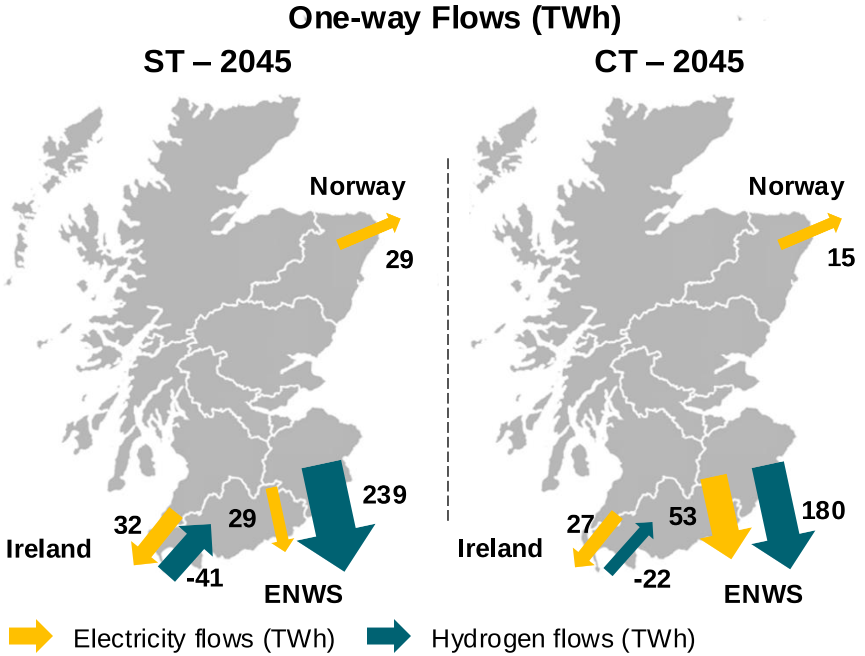
[1]Contains residual renewable and non-renewable energy supplies.[2]Import/Export' refers to net importing energy when the value is positive, and net exporting energy when the value is negative.

ST | CT | Scenario

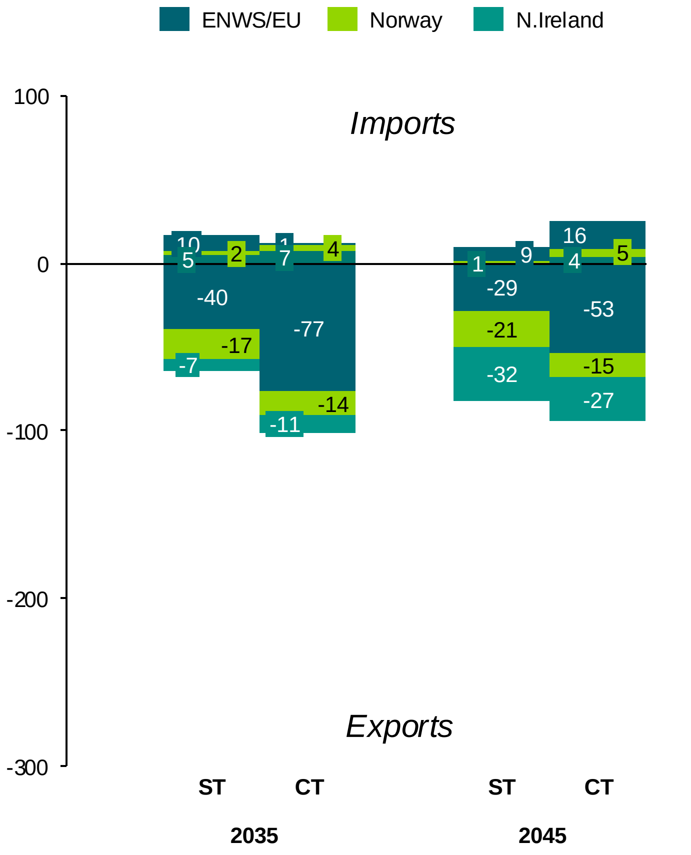
England and Wales, as well as Continental Europe are the main destinations for both Scottish electricity and hydrogen exports

Key Messages

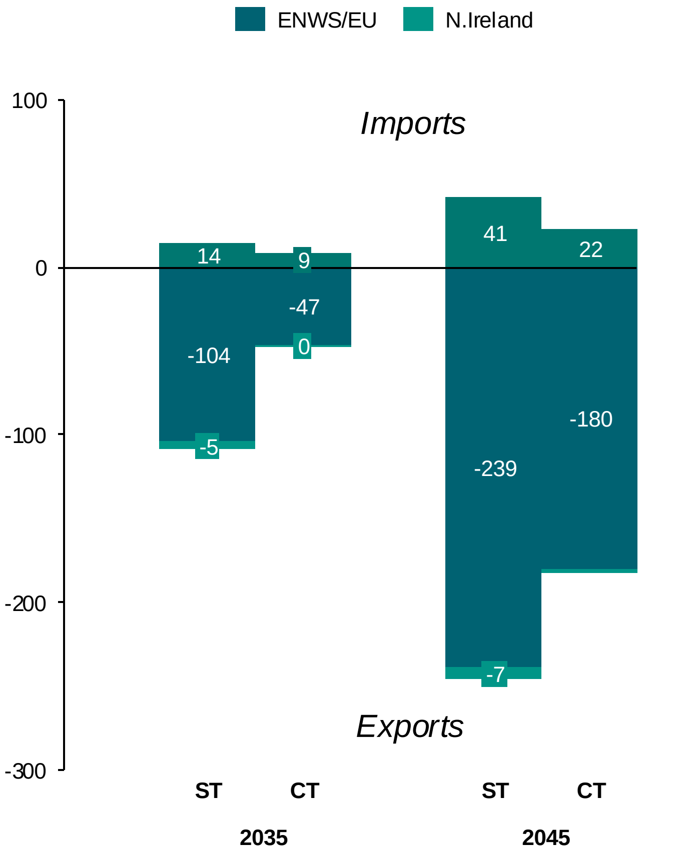
- **Most of the hydrogen and electricity exports go south into England and Continental Europe**, but Scotland also exports electricity to Ireland & the Nordics
- Existing interconnectors are leveraged to **export electricity** to (N.) Ireland and **import (N.) Irish hydrogen,** transiting in Scotland towards England.



Electricity Export/Import, TWh_{elec}



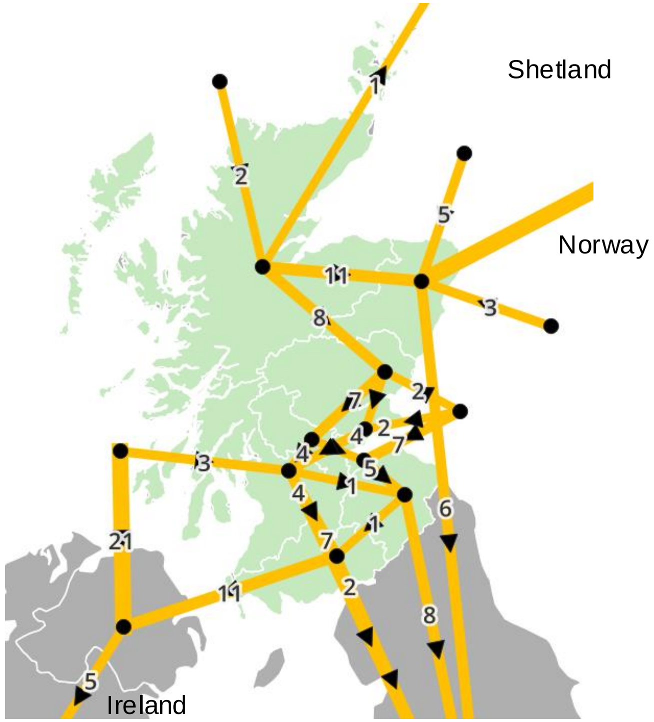
Hydrogen Export/Import, TWh_{H_2}



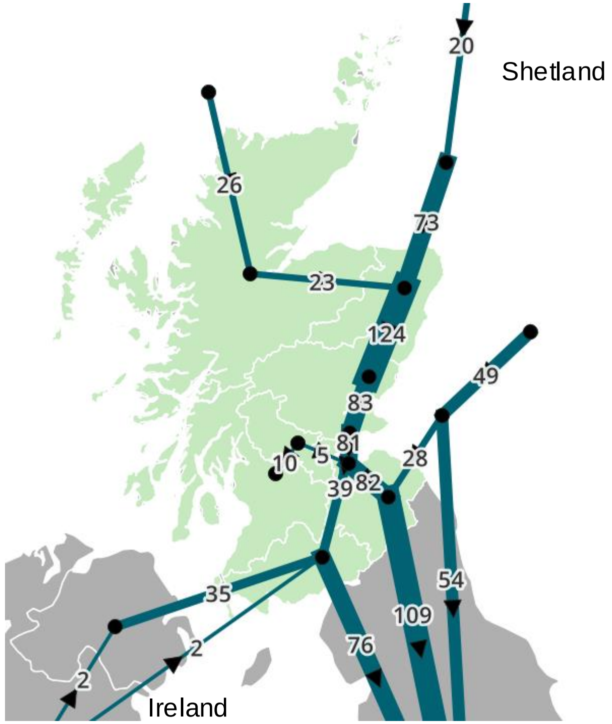
ST CT Scenario

In ST, hydrogen mainly flows from production centres in North Scotland down to England and Europe alongside the east coast of Scotland

Electricity & Hydrogen Net Flows in ST (TWh)



Export to England & Wales (incl. Europe)



Export to England & Wales (incl. Europe)

2045 – Electricity

Large number of flows across the nodes, with largest being for export

2045 – Hydrogen

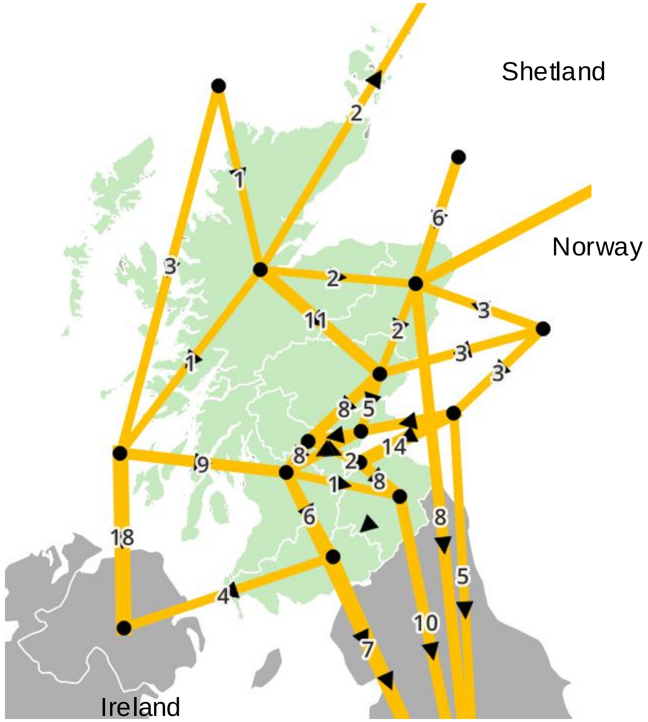
The hydrogen flow builds up from Shetland all the way down to ENWS

Key Messages

- Hydrogen is exported **via three routes** to England and Wales, with the **South-eastern onshore connection** contributing the most with 109 TWh.
- Electricity flows are more **distributed across demand centres in Scotland**, whereas hydrogen flows are largely **centred towards exports.**
- There are **large volumes of energy imports and exports between Scotland and Ireland,** interestingly resulting in a net export of electricity to Ireland, but net imports of hydrogen.
- Electricity exports to Ireland can be explained by the optimisation of **Ireland's green hydrogen production capacity**. Subsequently, excess Irish production is transiting through Scotland for export purposes to England and Europe.
- Some of the green hydrogen produced in Ireland is then **exported using the same route as Scottish hydrogen**, leveraging existing gas interconnectors repurposed to hydrogen.

The net energy flow patterns in CT closely resemble those in ST, indicating consistency in infrastructure requirements across scenarios

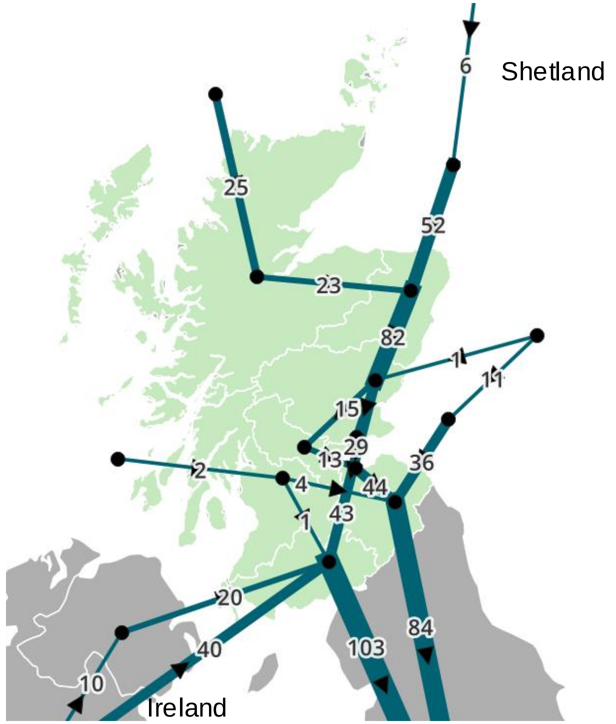
Electricity & Hydrogen Net Flows in CT (TWh)



Export to England & Wales (incl. Europe)

2045 – Electricity

A larger number of connections but lower overall flows than hydrogen



Export to England & Wales (incl. Europe)

2045 – Hydrogen

Dominates the overall flow similarly to ST

Key Messages

- Hydrogen and electricity flows within Scotland and with its neighbours **paint the same picture in CT and ST.**
- The similarities in energy flows between ST and CT demonstrate the **"low-regret" nature of some investments** in both electricity and hydrogen transmission.
- As expected, electricity flows are **more substantial in CT** due to the increase in demand in Scotland and England.
- Similarly, hydrogen flows are reduced in this scenario, particularly within Scotland.

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Scotland's Electricity System Development

This section presents detailed **electricity system results** from two different **whole energy system scenarios**:

System Transformation | Consumer Transformation

No New Infrastructure | EU Renewables +20% | New Build Only | H_2 Storage

What is covered:

- Electricity Demand
- Electricity Supply
- Electricity Infrastructure
- Electricity Daily Supply/Demand Profiles

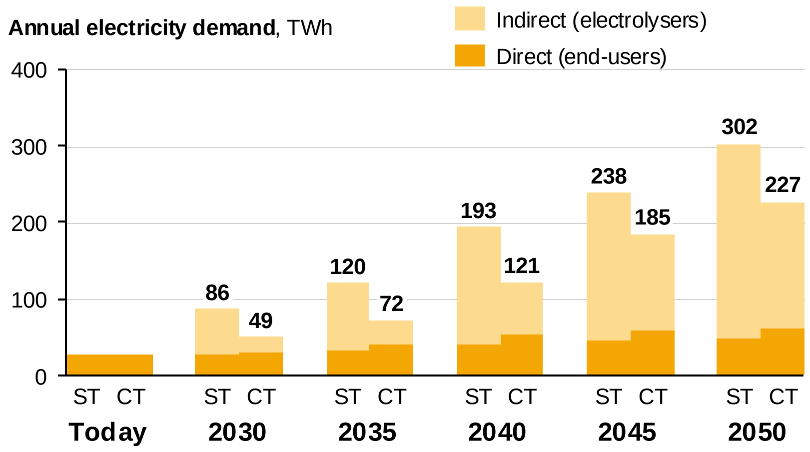
ST CT Scenario

In both scenarios, electricity demand increases significantly from today to 2050, boosted by electrolyser demand

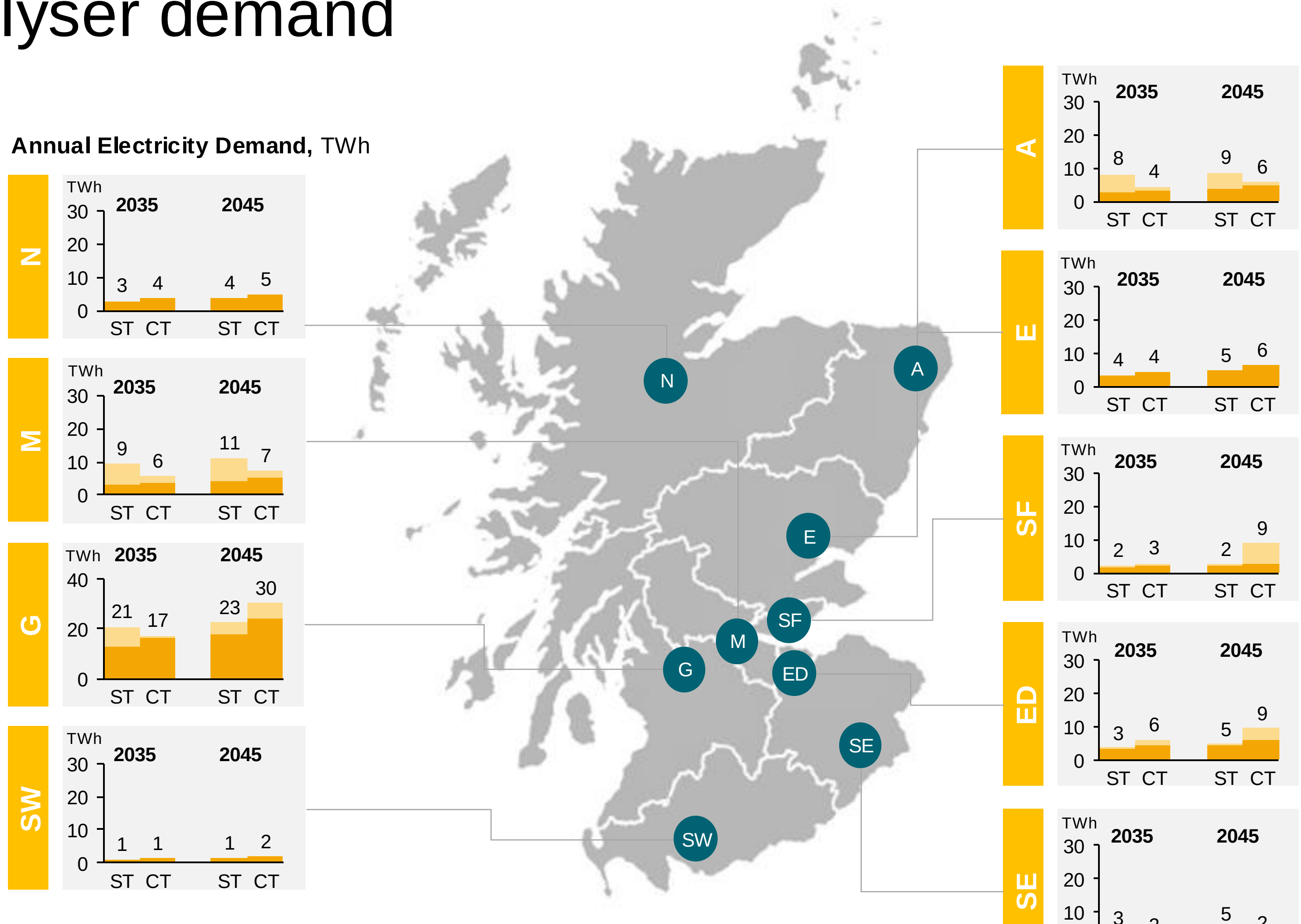
Key Messages

- **Direct electricity demand is highest in the CT scenario** across all projected years, but **total demand is highest in the ST scenario** due to dominating indirect demand from electrolysers.
- In 2045, indirect electricity demand for electrolysers takes **69% and 82% of the total electricity demand** in the CT and ST scenarios respectively in Scotland.
- The indirect electricity demand significantly increases from 2035 onwards and highlights the **importance of integrated planning** in the future Scottish energy system in all scenarios.

Annual electricity demand, TWh



Annual Electricity Demand, TWh



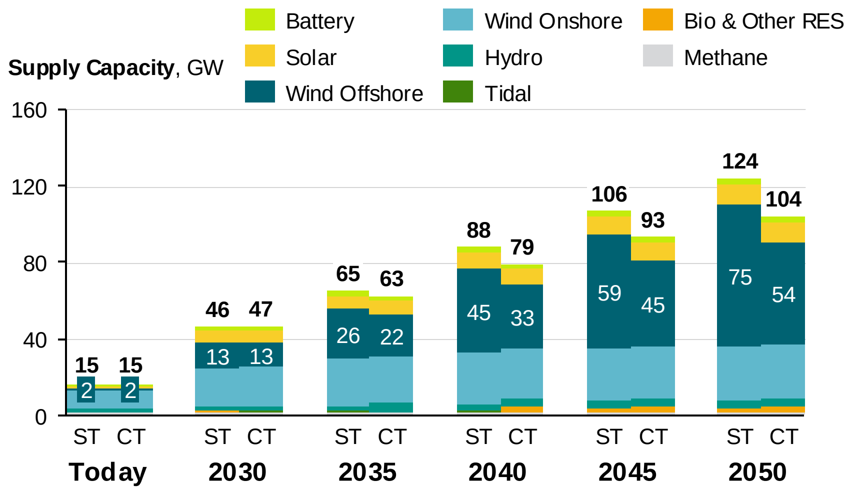
*Shetland and offshore nodes are excluded from the map

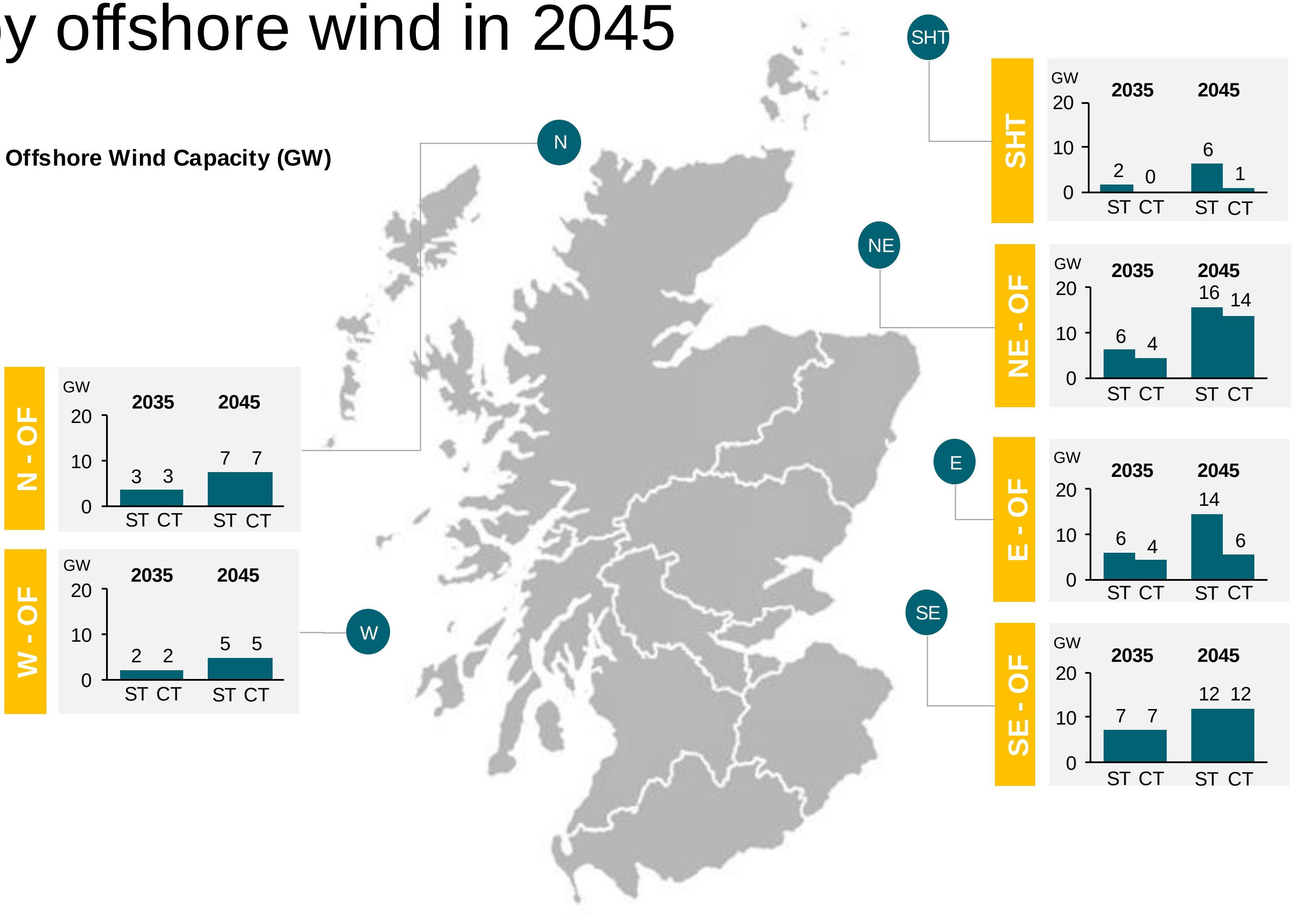
ST CT Scenario

To meet this increase in electricity demand, renewables capacity scales rapidly, largely dominated by offshore wind in 2045

Key Messages

- In both scenarios, **offshore wind power** dominates the overall Scottish electricity supply capacity, accounting for **48 - 56% of total installed capacity** by 2045
- In both scenarios, most of the **power production** is generated on the East Coast of Scotland
- For the ST scenario, offshore wind constantly reaches the upper bound constraint (e.g., 59.4GW by 2045). In comparison, offshore wind capacities in the CT scenario are lower, due to overall lower hydrogen demand and higher offshore wind costs.





*Onshore nodes are excluded from the map

ST CT Scenario

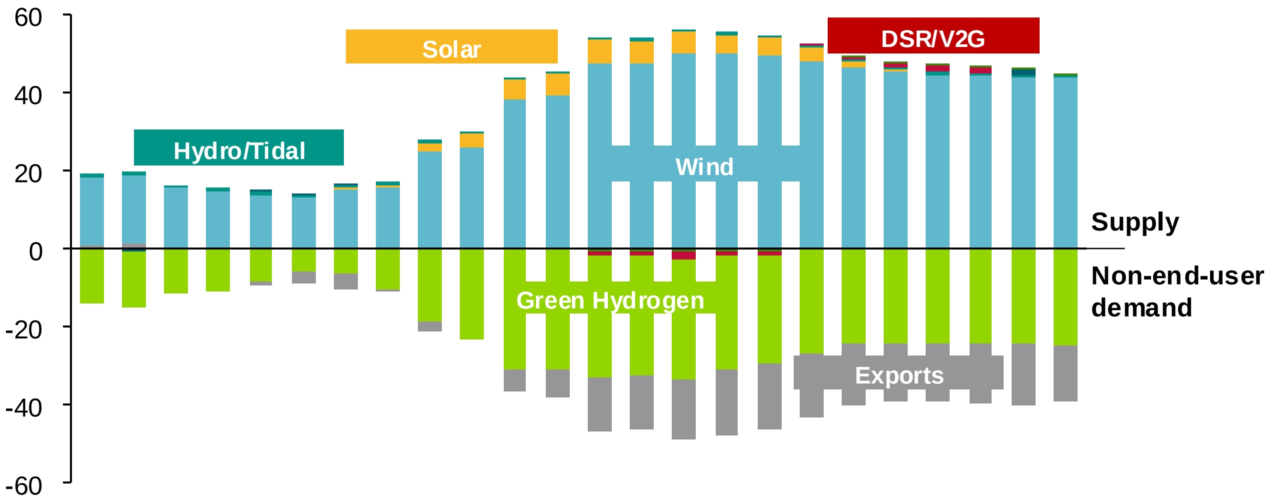
Electricity exports and imports play a key role in maximising the value of renewables while ensuring system resilience in Scotland

Key Messages

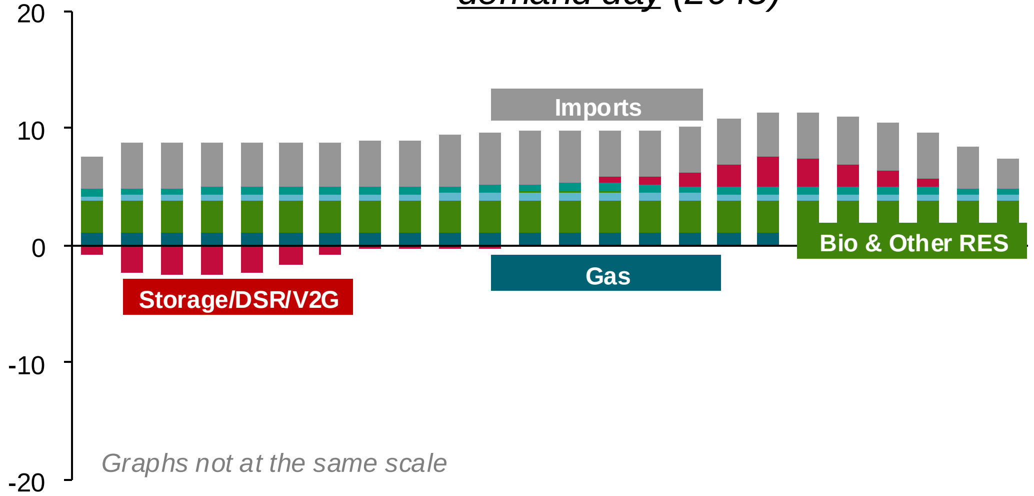
- Throughout most of the year (e.g., a normal spring day in 2045), **wind generation dominates the supply mix**, far exceeding domestic Scottish electricity demand – most of the power production is thus used to generate green hydrogen through electrolysis and exports.
- **Dispatchable power generation,** such as biomass and hydrogen/natural gas with CCS turbines**,** remains an important asset in 2045 to help **supply domestic electricity demand** in Scotland on days with limited wind supply.
- **Interconnection** with Ireland, Norway, and the rest of Great Britain **creates significant value to Scotland** throughout the year by enabling large volumes of electricity exports during a normal day and importing crucial power to meet Scottish power demand during limited wind, peak demand days.

Consumer Transformation results[1]

System balance for a standard spring day (2045)



System balance for a limited wind, peak demand day (2045)



[1]Graphs only show power supply resources (e.g., wind, solar, storage, etc.) and not end-user demand (e.g., buildings, industry, etc.);

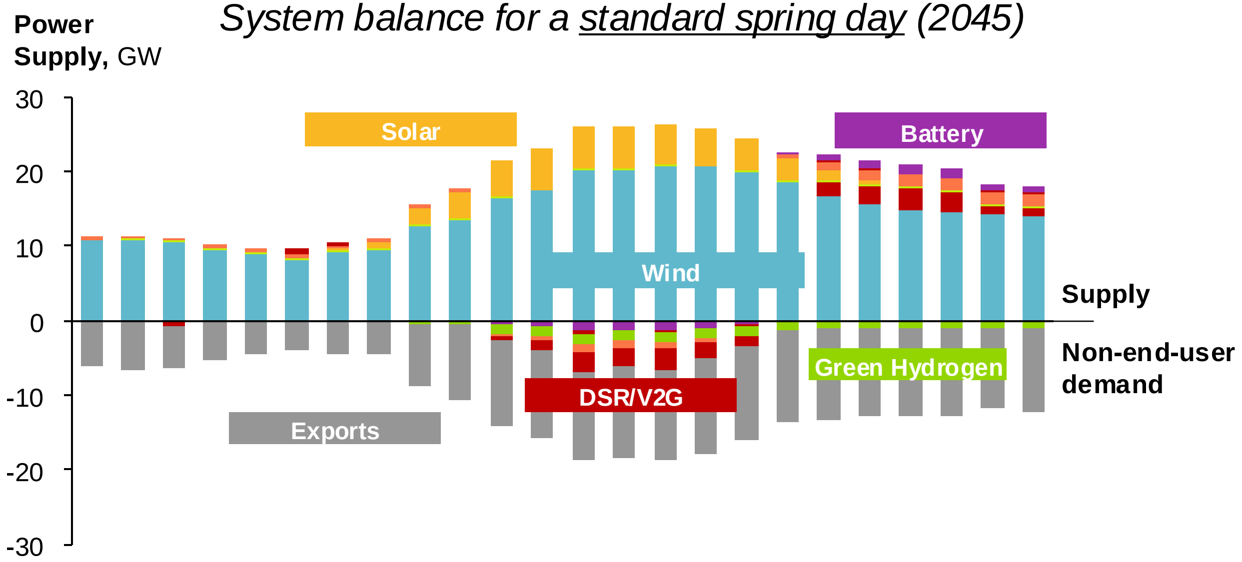
Without additional electricity and hydrogen interconnection with England, Scotland relies further on existing infrastructure, stressing the system

Key Messages

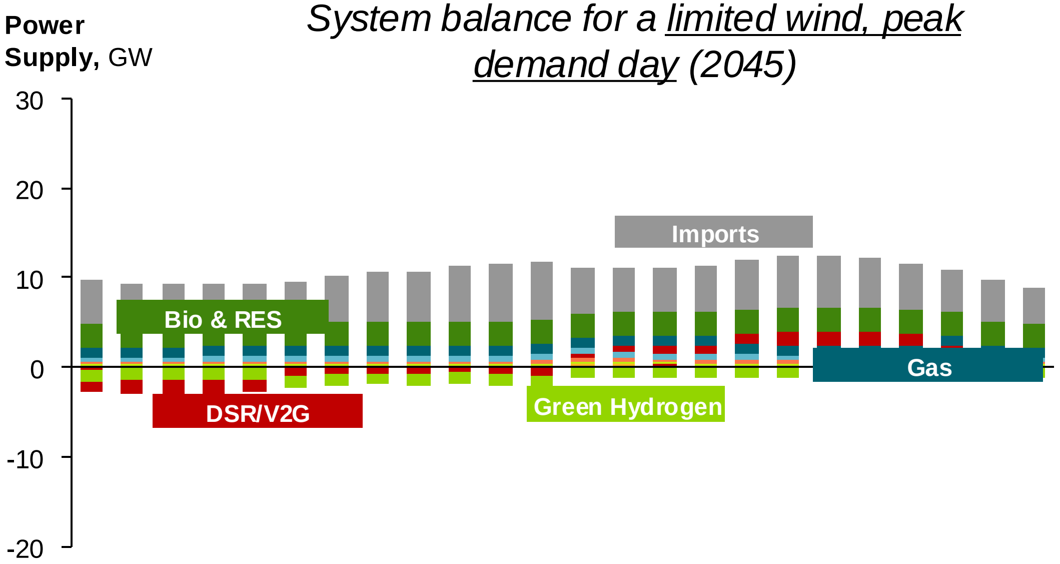
- Without investment in new electricity and hydrogen transmission infrastructure, Scotland, much like today, leverages its existing interconnection to export excess supply throughout the day, while **importing large volumes of electricity during limited wind, peak demand day.**
- Without the opportunity to export hydrogen, significantly less wind power production capacity is thus developed as demand for electrolysis significantly drops.
- **System flexibility**, both in a high wind day and low wind day, is thus **reduced by the lack of optionality** that would be provided by additional electricity and hydrogen infrastructure investments.

Consumer Transformation results[1]

System balance for a standard spring day (2045)



System balance for a limited wind, peak demand day (2045)



[1]Graphs only show power supply resources (e.g., wind, solar, storage, etc.) and not end-user demand (e.g., buildings, industry, etc.);

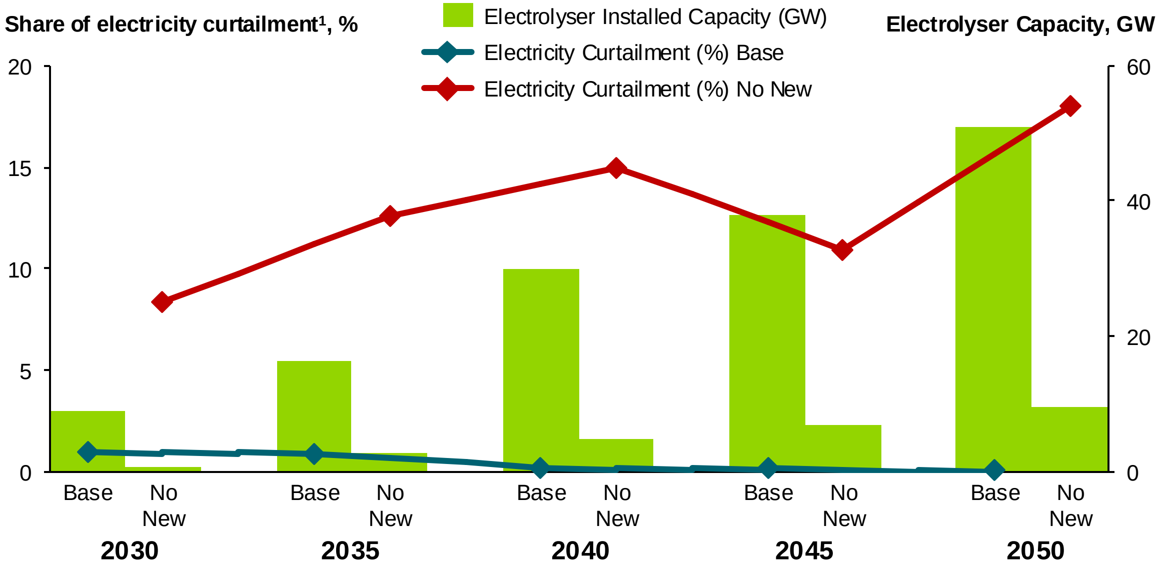
Without new hydrogen or electricity transmission infrastructure, renewable curtailment in Scotland significantly increases

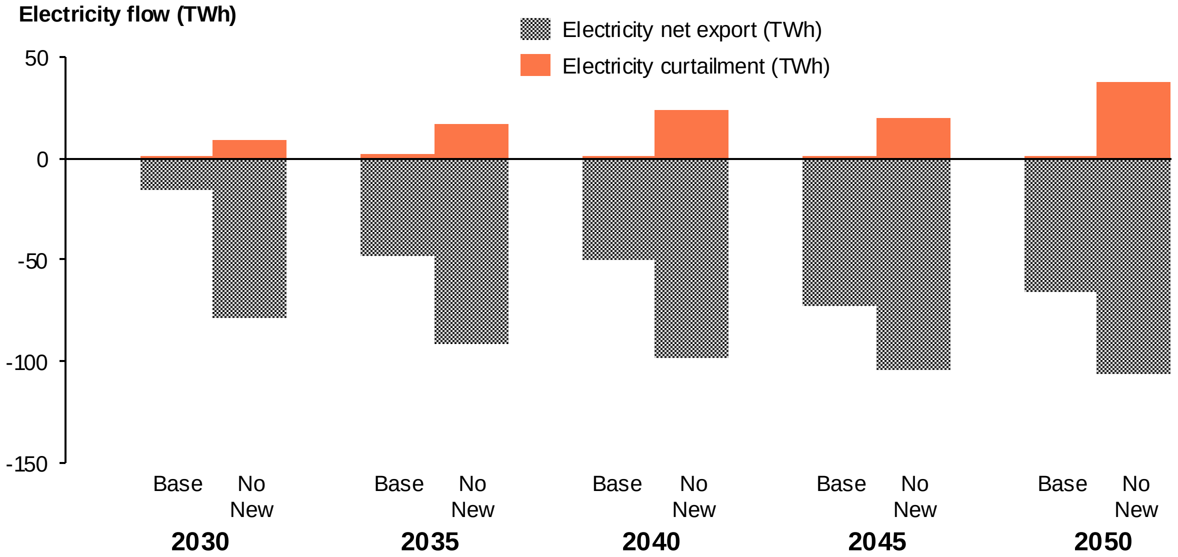
As expected, electrolysers significantly reduce curtailed power

- There is a **clear correlation** between higher electrolysis installed capacity and decreased curtailment.
- Without export hydrogen infrastructure in place, the capacity of installed electrolyser's is **significantly reduced**, causing renewable curtailment to increase significantly, **up to 18%** in 2045. In turn, this impacts the cost of hydrogen, increasing from **£1.7/kg to £2/kg.**[1]
- Thus, a hydrogen infrastructure enabling exports directly improves the business case for both renewable and electrolyser developers.

Greater power exports are not sufficient to reduce curtailment

- Without new hydrogen or electricity infrastructure, the **existing interconnections are maximised**
- The reason for higher exports despite lower infrastructure capacities, is that now Scotland is maximising its existing electricity connections to export electricity to neighbouring regions as there is **no opportunity to export hydrogen** but still a large renewable electricity generation potential



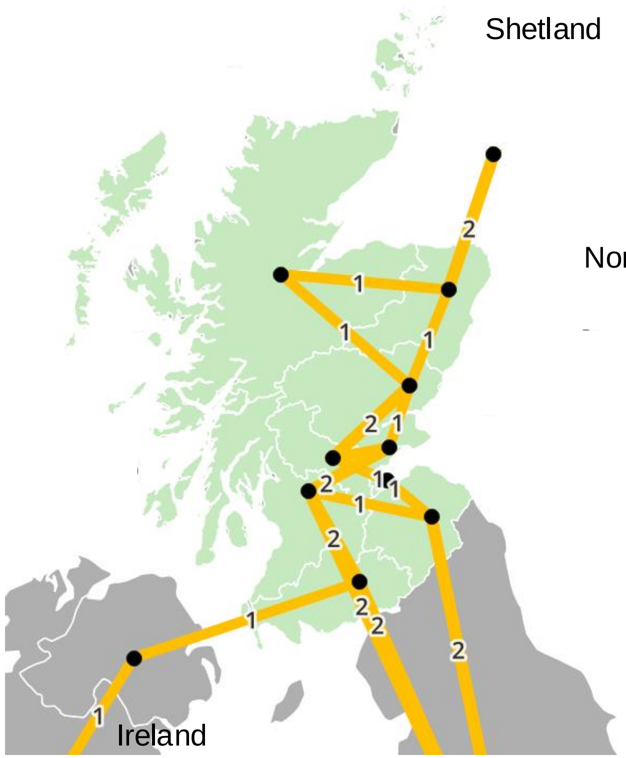


[1]The analysis does not consider curtailment due to transmission & distribution network constraints. It only considers curtailment caused by generation outstripping demand

Large electricity transmission investments are required between today and 2035 but stagnate thereafter as hydrogen infrastructure develops

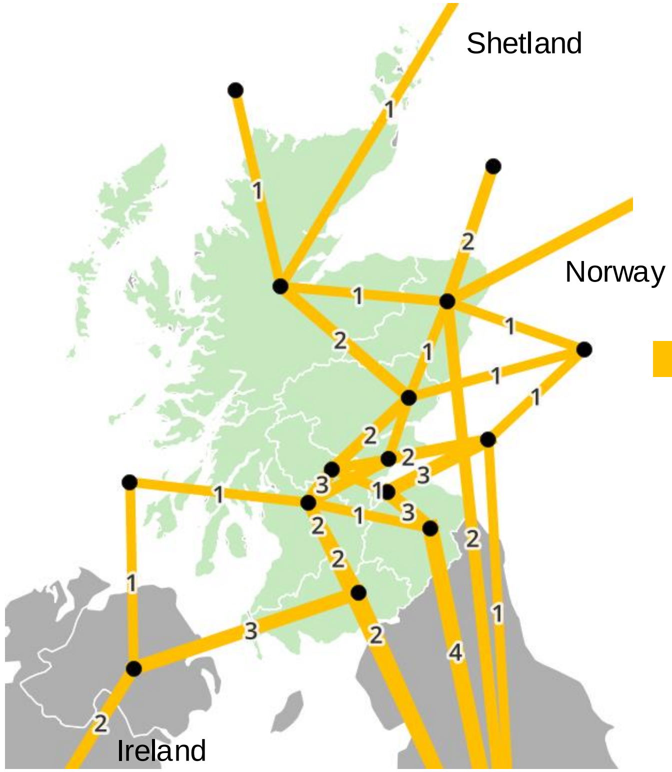
Electricity transmission infrastructure capacities between modelled nodes (GW) – Consumer Transformation

Today



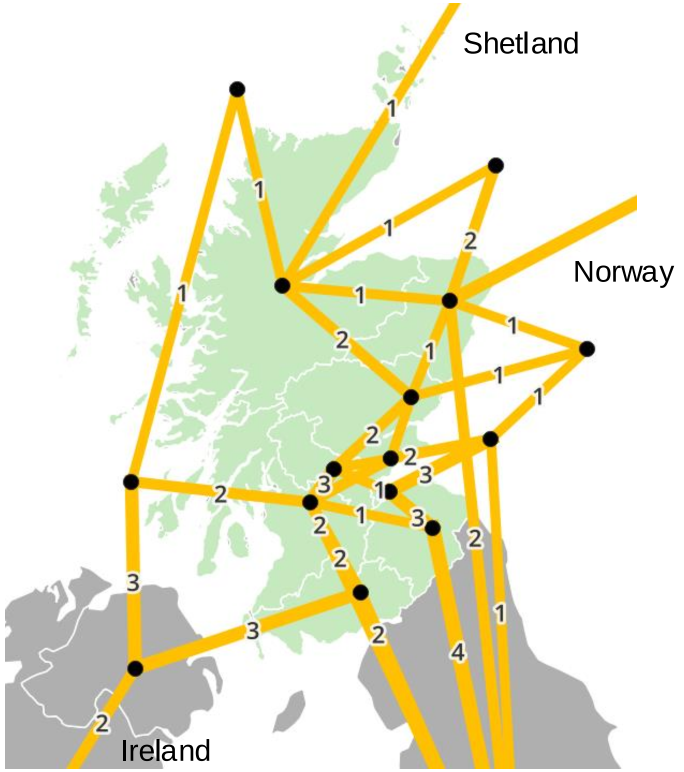
Export to England & Wales (incl. Europe)

2035



Export to England & Wales (incl. Europe)

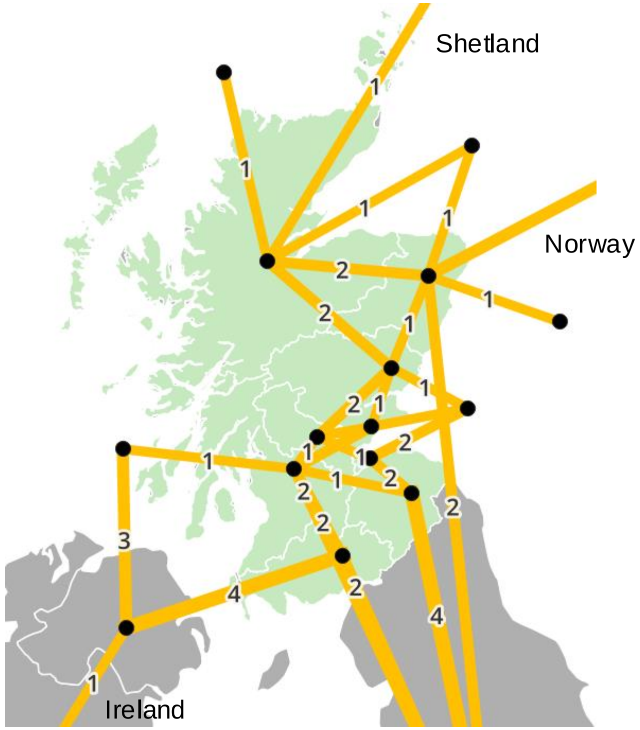
2045



Export to England & Wales (incl. Europe)

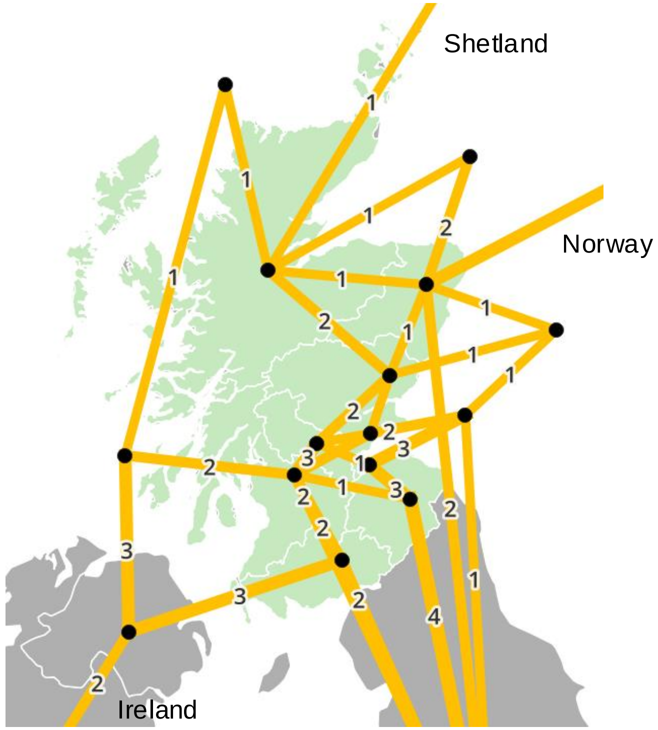
Similarities in electricity transmission network development across both scenarios highlight the low-regret nature of infrastructure investments

Electricity transmission infrastructure capacities between modelled nodes (GW)



2045 – ST

Despite being a hydrogen-focused scenario, 2045 grid development is similar to CT



2045 – CT

The grid development in CT is marginally higher than in ST

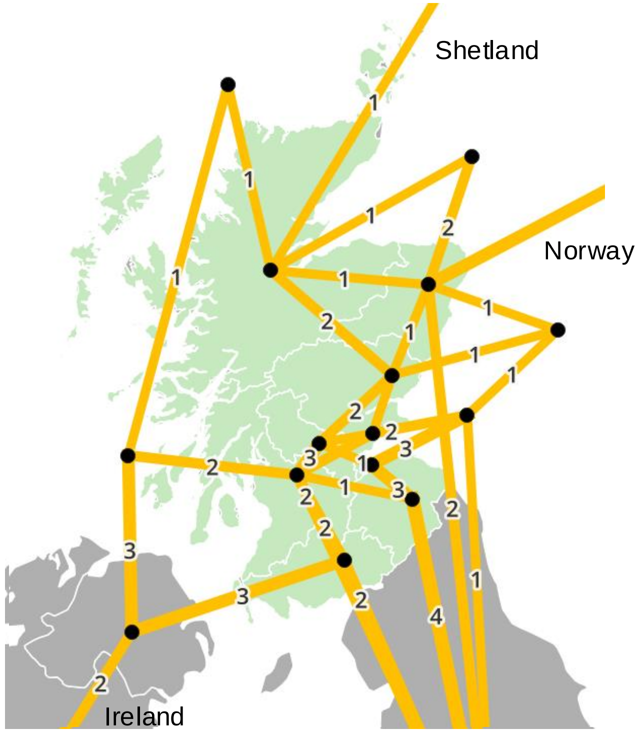
Key Messages

- **Both scenarios show a need for significant development in electricity transmission**. The scale and design of the network, however, differs depending on the domestic and neighbouring regions' electricity demand.
- In both scenarios there is a development of direct connections from Scotland's **offshore nodes** directly to neighbouring countries, where the connection from a south-eastern offshore node to England is the biggest connection developed in 2045 – **4 GW.**
- CT demonstrates an **increase of 7 GW** in the buildout of electricity transmission by capacity, compared to ST, but the number of connections is almost the **same** across the two scenarios.
- The main difference between the two scenarios is in the **capacity increase** of connections within Scotland, rather than export. This is due to the **larger direct demand** of the CT scenario.

ST | CT | Scenario | EU Renewables +20% | *Sensitivity*

Additionally, Scotland's electricity infrastructure would not be impacted by a higher renewable buildout in its neighbouring regions

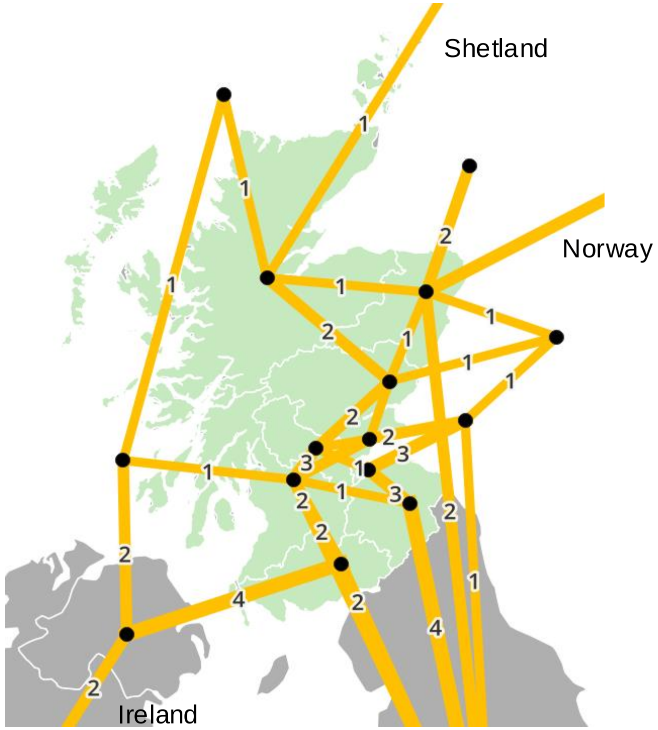
Electricity transmission infrastructure capacities between modelled nodes (GW)



Export to England & Wales (incl. Europe)

2045 – CT

Maximum grid development across tested scenarios and sensitivities



Export to England & Wales (incl. Europe)

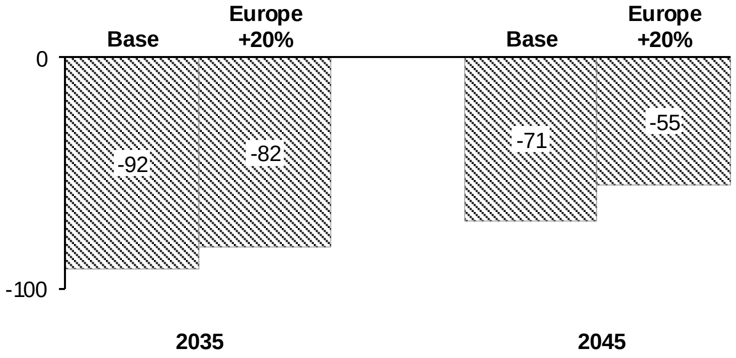
2045 – CT (EU Renewables + 20%)

Same development despite a decrease in demand from neighbouring regions

Key Messages

- In this sensitivity, Scotland's power exports **fall by 16TWh** between two scenarios, however, electricity transmission infrastructure capacity **is not impacted**.
- Indeed, the electricity transmission capacities between Scotland and England are still needed to **balance the GB system** during peak demand days with limited wind.
- Within Scotland, the electricity transmission capacity also largely remains **unchanged**.

Electricity Net Export, TWh_{elec}



Scotland's Hydrogen System Development

This section presents detailed **hydrogen system results** from two different **whole energy system scenarios and sensitivities**:

System Transformation | **Consumer Transformation**

No New Infrastructure | EU Renewables +20% | **New Build Only** | **H_2 Storage**

What is covered:

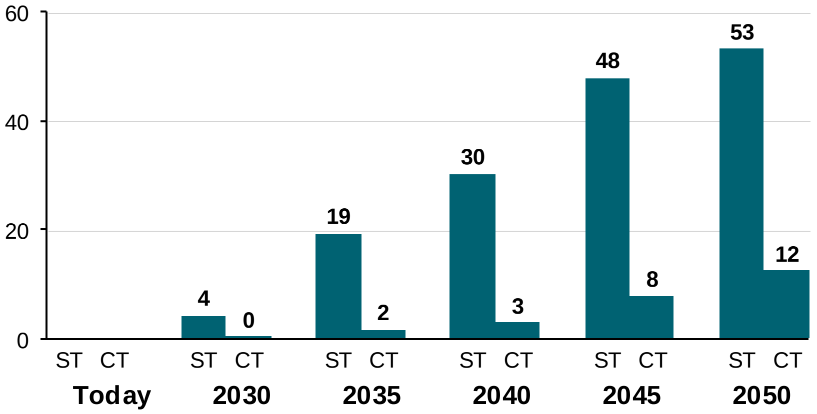
- Hydrogen Demand
- Hydrogen Supply
- Hydrogen Infrastructure
- Hydrogen Daily Supply/Demand Profiles

Hydrogen demand is significantly higher in System Transformation, mainly driven by hydrogen use for residential heat in this scenario

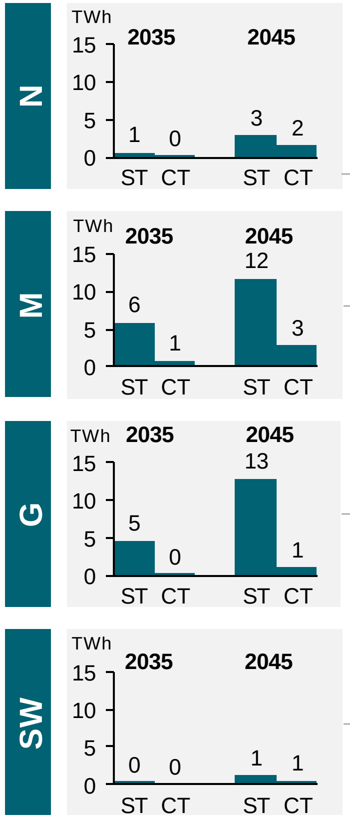
Key Messages

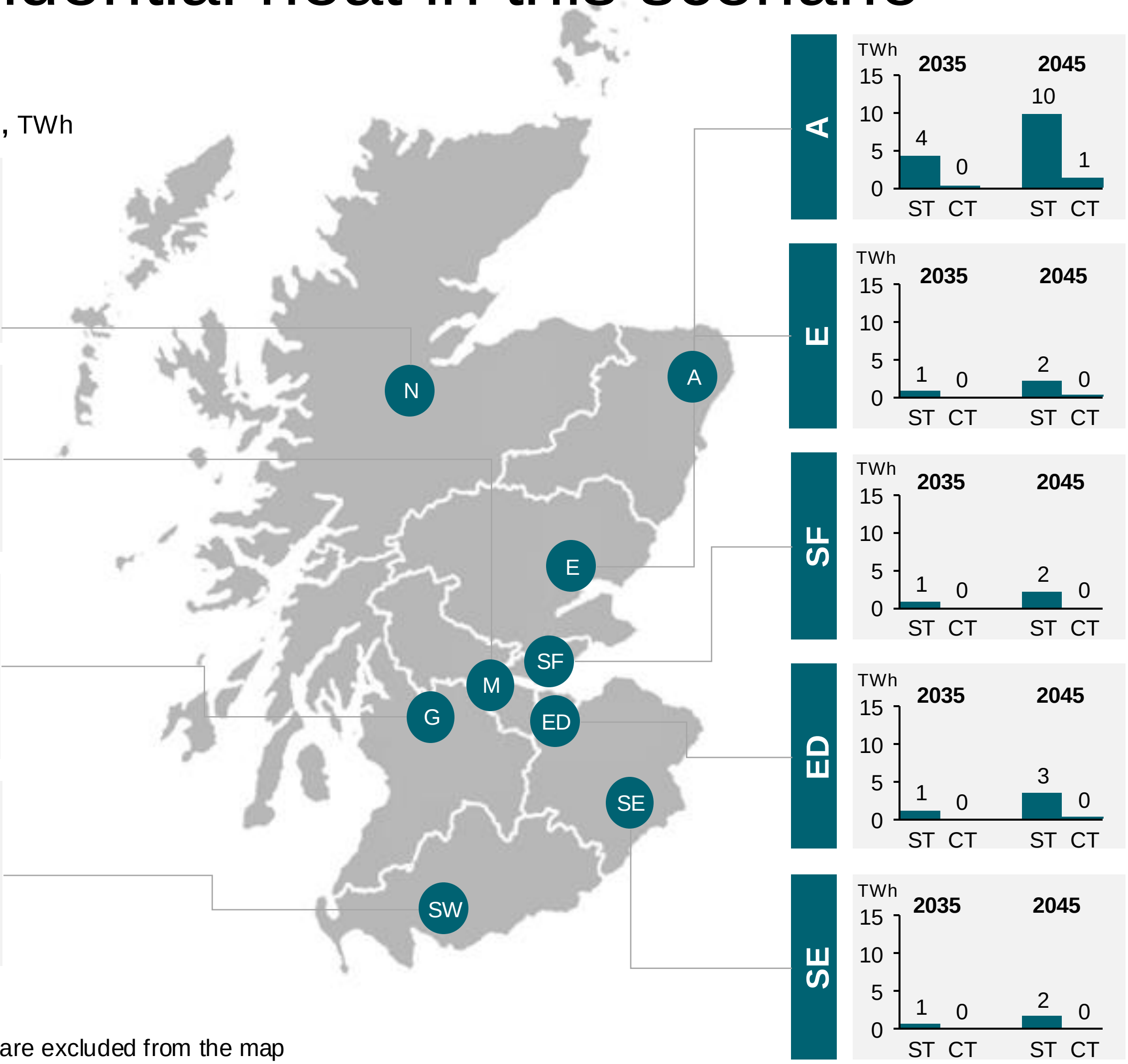
- **Annual hydrogen demand is much higher in the ST scenario** compared to CT (41 TWh higher), mainly driven by residential heating and industrial demand.
- **In ST, hydrogen for buildings accounts for the largest share of demand** compared to other demand sectors. In CT, hydrogen for buildings contributes the least of all sectors.

Annual hydrogen demand, TWh



Annual Hydrogen Demand, TWh





*Shetland and offshore nodes are excluded from the map

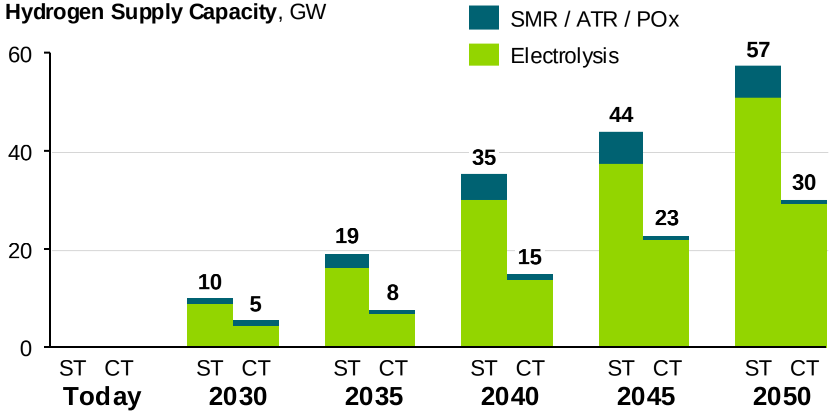
ST CT Scenario

However, hydrogen production remains significant across both scenarios driven, in both cases, by exports

Key Messages

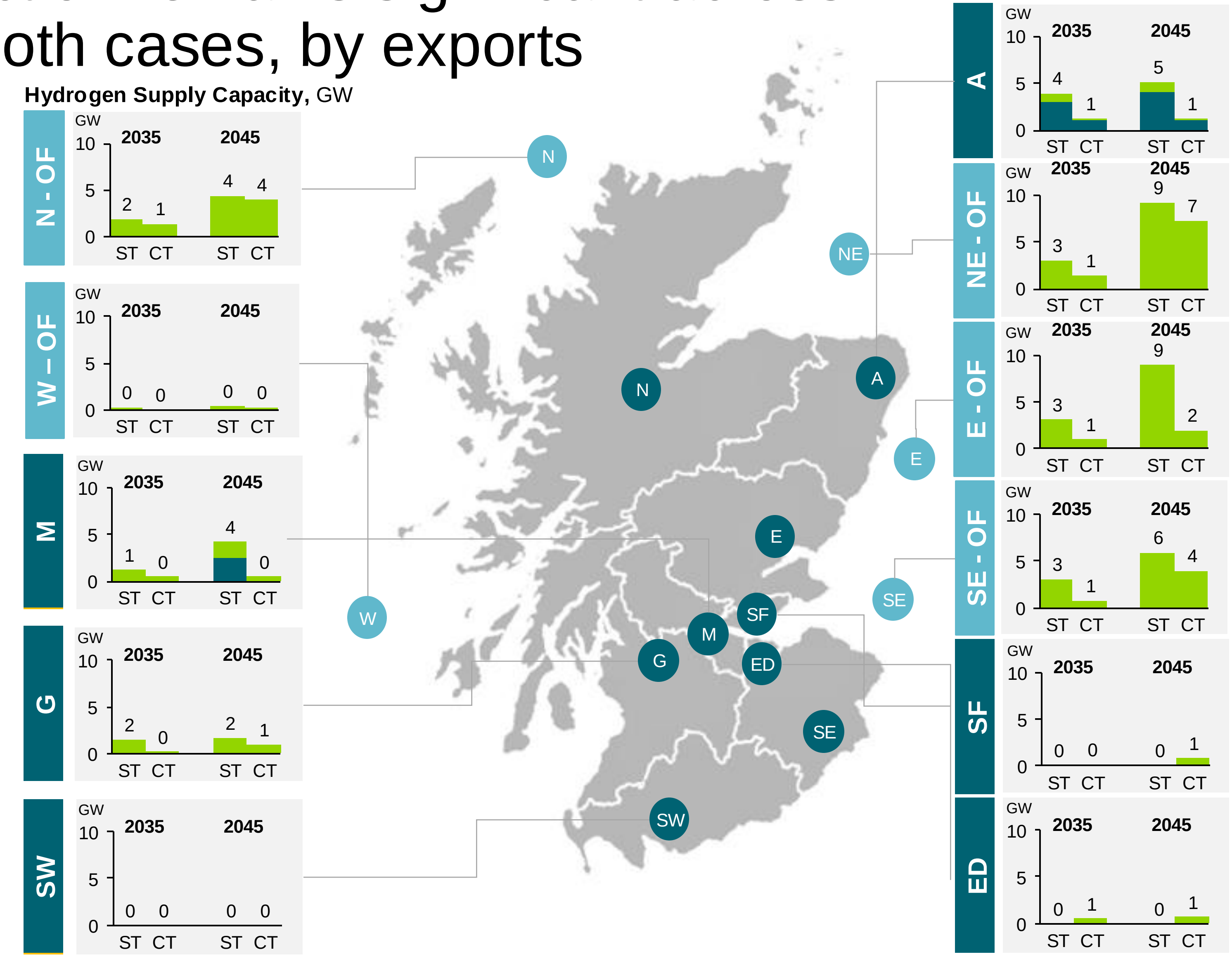
- In both scenarios, **hydrogen production capacity is largely dominated by electrolysis** across all years, with between 85 – 95% of installed capacity.
- In both scenarios, green hydrogen production capacity is primarily **co-located with offshore wind**, indicating that offshore production is cost-effective. In practice, offshore investments are financially riskier and require greater coordination than onshore.
- By 2030, hydrogen production capacity rapidly scales up to **10 GW in ST**, exceeding Scottish Government targets, while it falls short of the target by **1 GW in CT.**

Hydrogen Supply Capacity, GW



*Includes supply from offshore and Shetland

Hydrogen Supply Capacity, GW

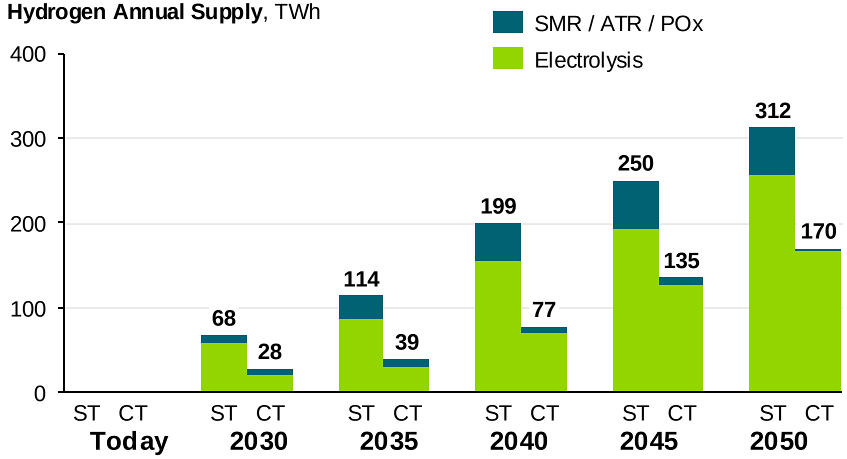


ST CT Scenario

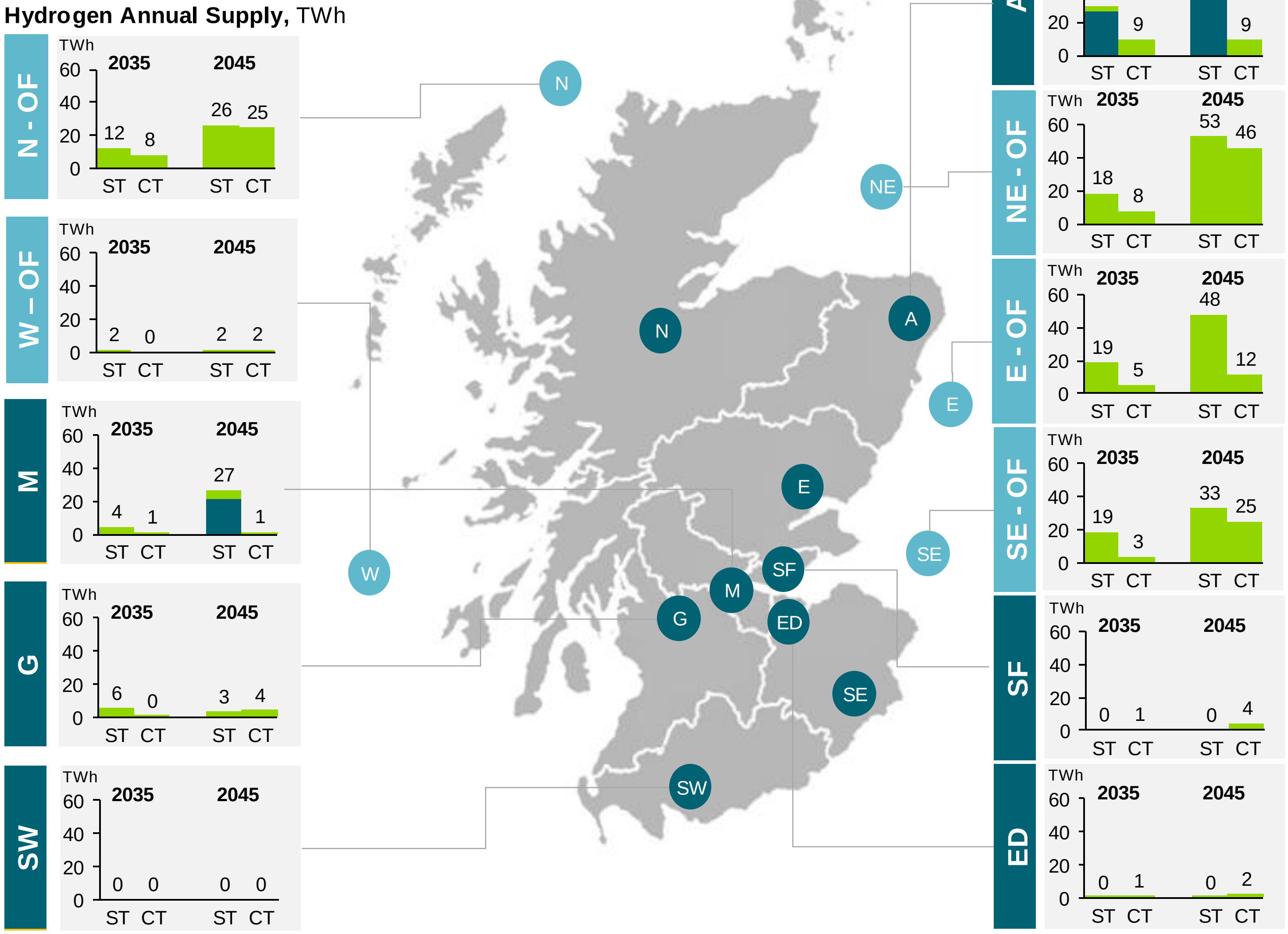
Green hydrogen dominates the hydrogen supply mix by 2045, but blue hydrogen still plays an export role in ST

Key Messages

- Electrolysers provide between **77% and 94% of the hydrogen produced** in Scotland in 2045, in ST and CT, respectively. The greater contribution of blue hydrogen in ST can be explained by its importance for meeting residential demand during low wind days.
- Blue hydrogen production is located in central Scotland and Aberdeenshire, where blue hydrogen is anticipated to develop due to industrial activity and proximity to CO_2 transport and storage infrastructure.



*Includes supply from offshore and Shetland

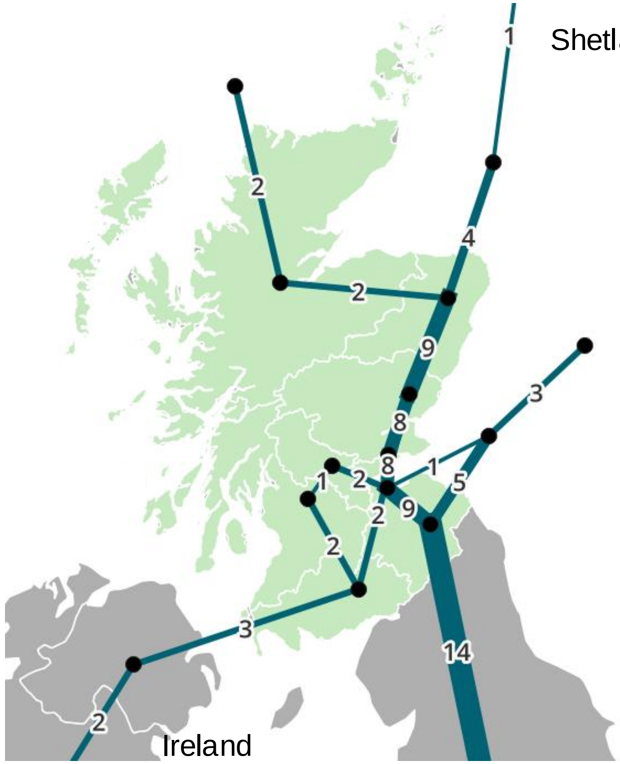


ST CT Scenario

Hydrogen transmission infrastructure in Scotland develops rapidly alongside the east coast, enabling exports to England and Europe

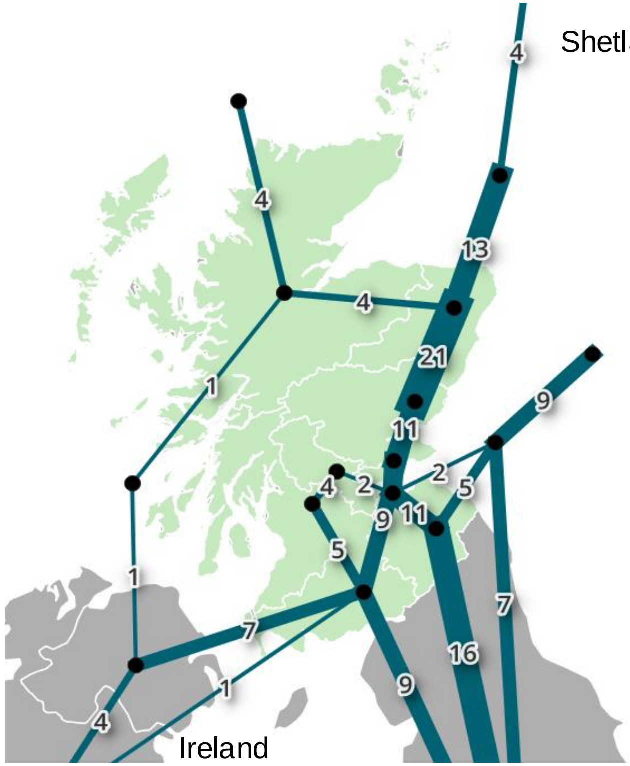
Hydrogen transmission infrastructure capacities between modelled nodes (GW) – System Transformation

2035



Export to England & Wales (incl. Europe)

2045

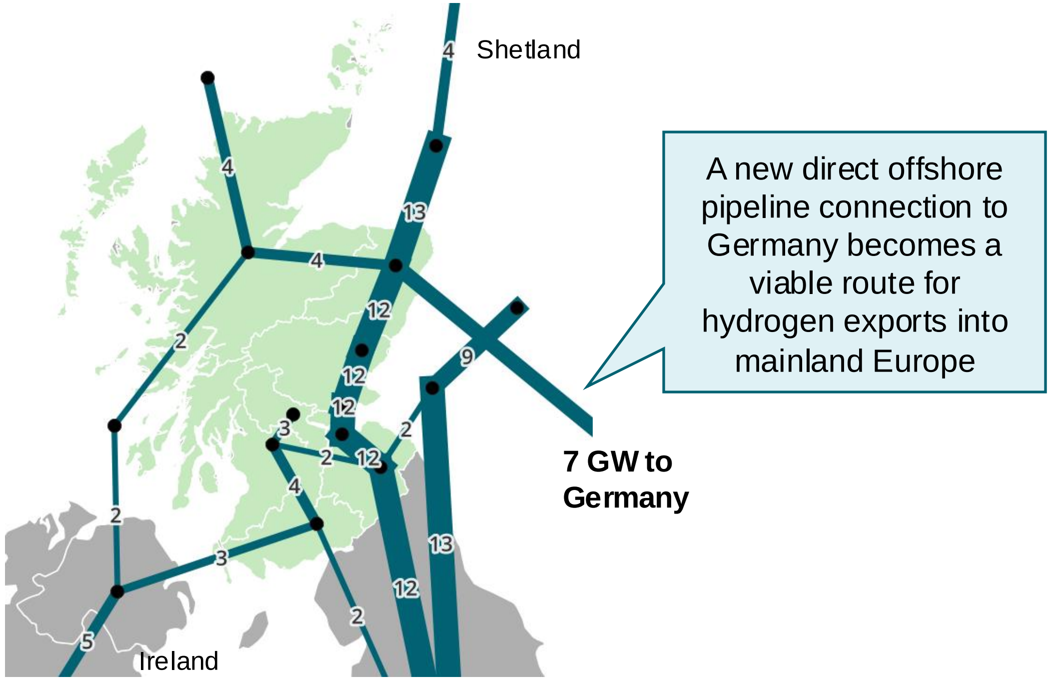


Export to England & Wales (incl. Europe)

The exact routing of exports is contingent on the ability to repurpose the existing gas network, but export volumes do not change

Hydrogen Infrastructure 2045 (GW) – ST (New Build)

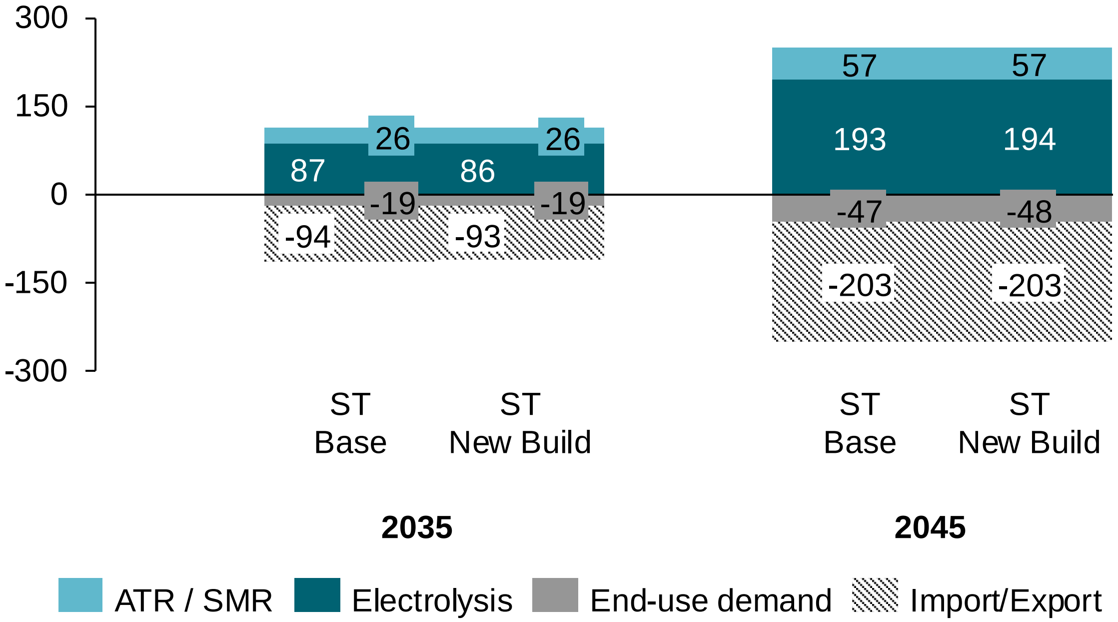
Without the ability to repurpose the existing methane pipeline to hydrogen, a new direct offshore connection from the north of Scotland to Germany now becomes a viable option.



Export to England & Wales (incl. Europe)

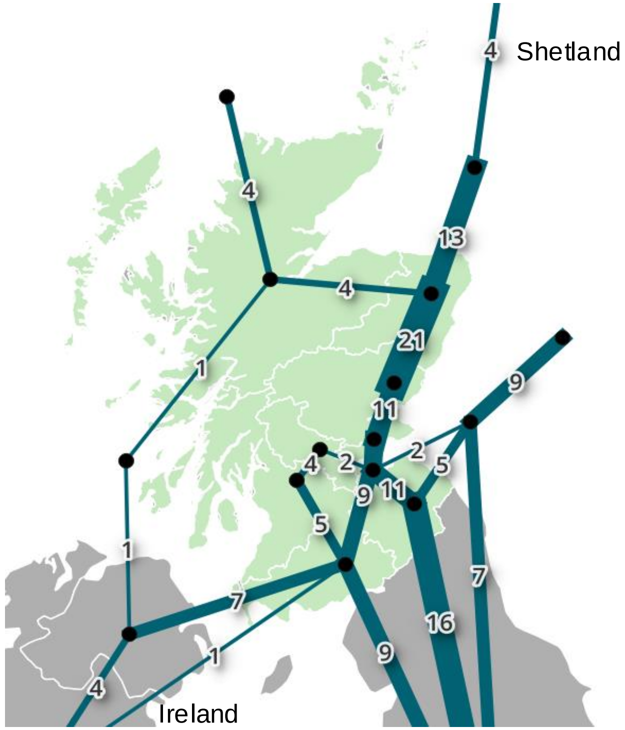
Scotland Hydrogen Export/Import, TWh_{H_2}

- However, the **export** of hydrogen **remains the same** despite an increase in transportation costs and is fully supplied via new pipelines.
- Thus, hydrogen exports from Scotland remain competitive independently of the ability to repurpose onshore pipeline, which is a positive outlook for Scotland's hydrogen industry.



Investments in hydrogen transmission from Scotland to England and Europe are needed to enable exports in both modelled scenarios

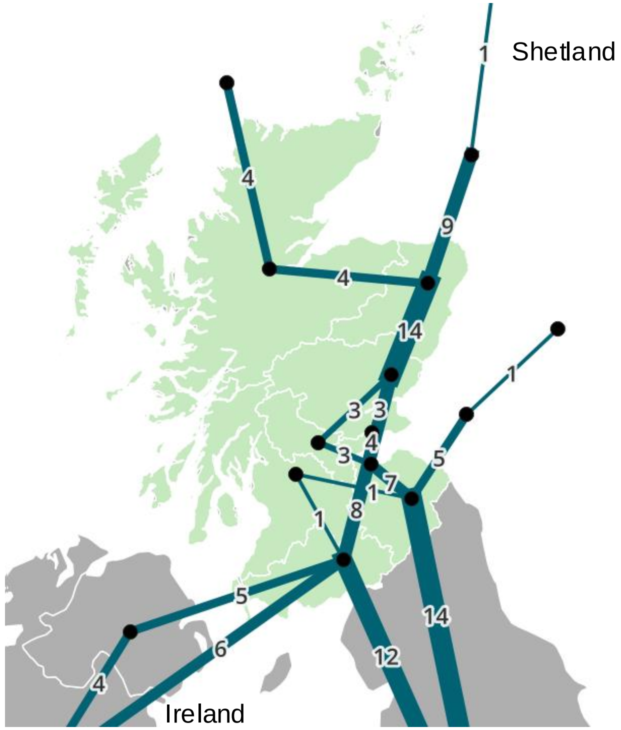
Hydrogen transmission infrastructure capacities between modelled nodes (GW)



Export to England & Wales (incl. Europe)

2045 – ST

Big pipeline buildout from Scotland to EN&WS, exporting hydrogen via 3 routes



Export to England & Wales (incl. Europe)

2045 – CT

Less buildout than in ST but still a lot of export to EN&WS via 2 routes

Key Messages

- Both scenarios demonstrate a **significant buildout** of hydrogen infrastructure across the country and for **exports**.
- **Hydrogen infrastructure buildout is more significant in ST**, as both endogenous and export demand are higher in this scenario.
- Most of the hydrogen infrastructure is developed alongside the **East Coast of Scotland** where most offshore wind, and thus electrolysers are located.
- Hydrogen pipeline interconnections to England and Ireland cumulate to **41 GW** of capacity. To reach this number**, newly built hydrogen pipelines will be required**, independently of the ability to repurpose existing pipelines.

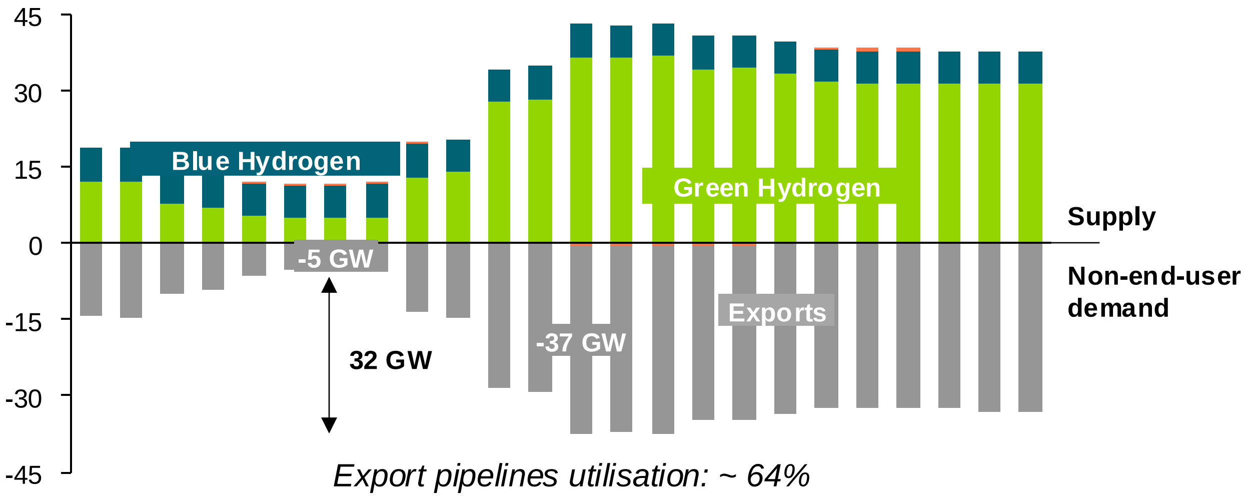
Hydrogen imports from England's hydrogen storage reserves play a key role in Scotland's energy system in peak demand days with limited wind

Key Messages

- **Hydrogen supply becomes significantly dependent on renewables**, much like electricity supply. On normal days, demand is met largely with green hydrogen; whereas on limited wind days, green hydrogen does not play a role – all electricity produced is used to meet end-user electricity demand.
- On limited wind days, hydrogen demand is met by **blue hydrogen** and through **imports from England's hydrogen storage sites.**
- The **volume of exports is very inconsistent** intra-day and across days. This situation can be a **challenge in contractual negotiations** with English and European off-takers who generally prefer a steadier hydrogen flow. It also causes lower pipeline utilisation which can hurt the business case for hydrogen pipeline.

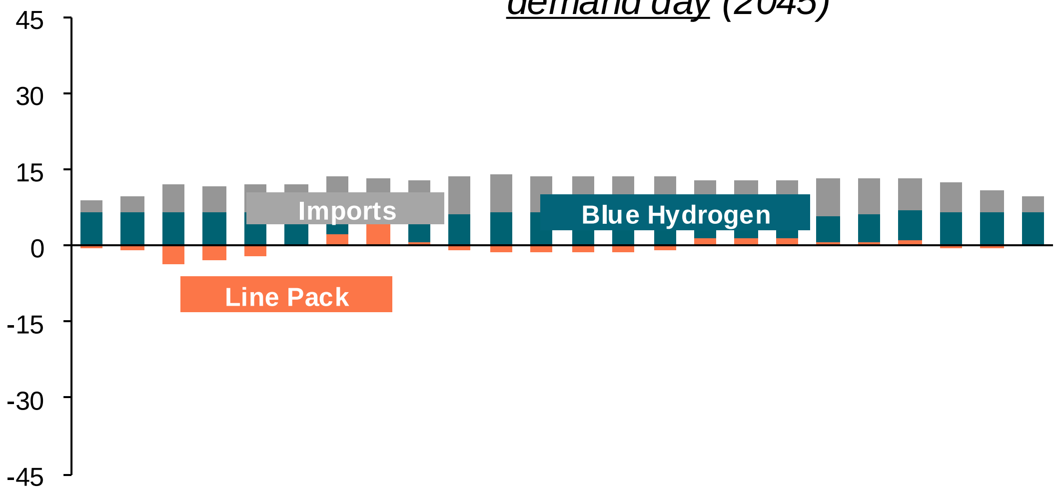
System Transformation results[1]

System balance for a standard spring day (2045)



Export pipelines utilisation: ~ 64%

System balance for a limited wind, peak demand day (2045)



[1]Graphs only show hydrogen supply resources (e.g., green and blue hydrogen, storage, etc.) and not end-user demand (e.g., buildings, industry, etc.).

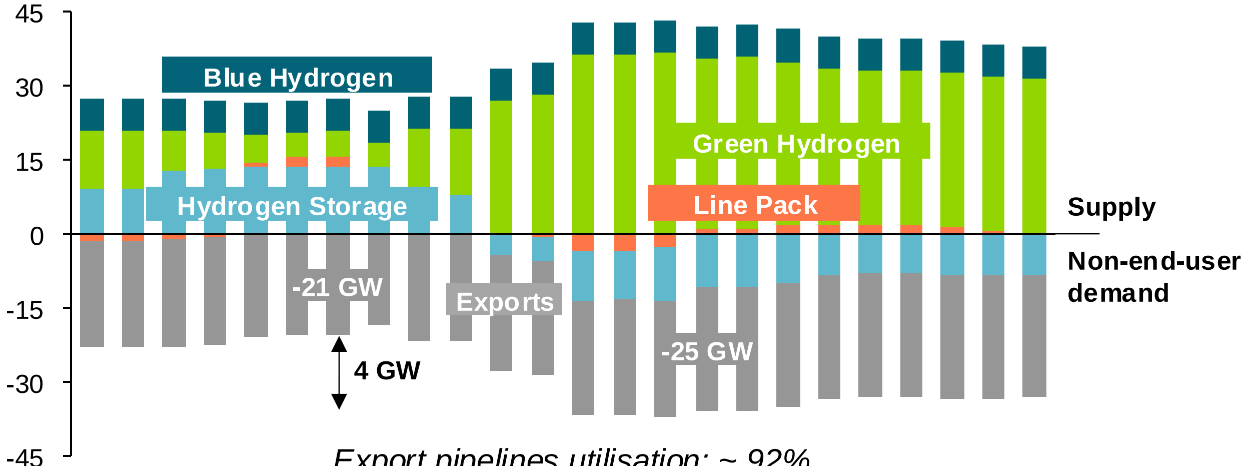
Developing hydrogen storage in Scotland would enable hydrogen export pipeline sizing optimisation and provide resiliency on low wind days

Key Messages

- **Developing hydrogen storage in Scotland could be a challenge** due to the lack of salt cavern resources. However, developing hydrogen storage from alternative options such as depleted Oil & Gas (O&G) fields could provide significant benefits, such as **greater hydrogen pipeline optimisation and system resiliency.**
- By storing a share of the green hydrogen production during high-wind days, **hydrogen storage in Scotland can help optimise pipeline utilisation** and reduce total required infrastructure capacity, thus lowering the levelized cost of hydrogen.
- During limited wind days, ~**14 GW** of hydrogen storage in Scotland provides system resiliency, enabling Scotland **to keep exporting rather than rely on imports.**

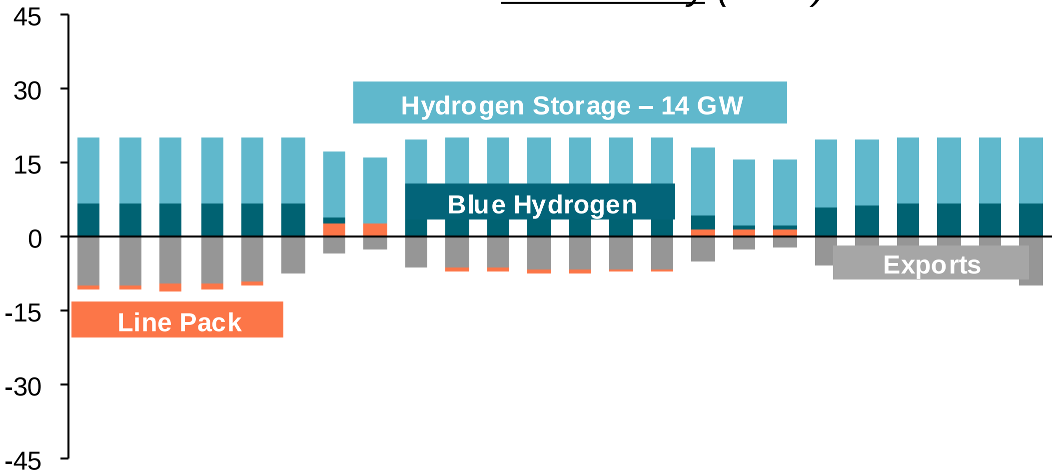
System Transformation results[1]

System balance for a standard spring day (2045)



Export pipelines utilisation: ~ 92%

System balance for a limited wind, peak demand day (2045)

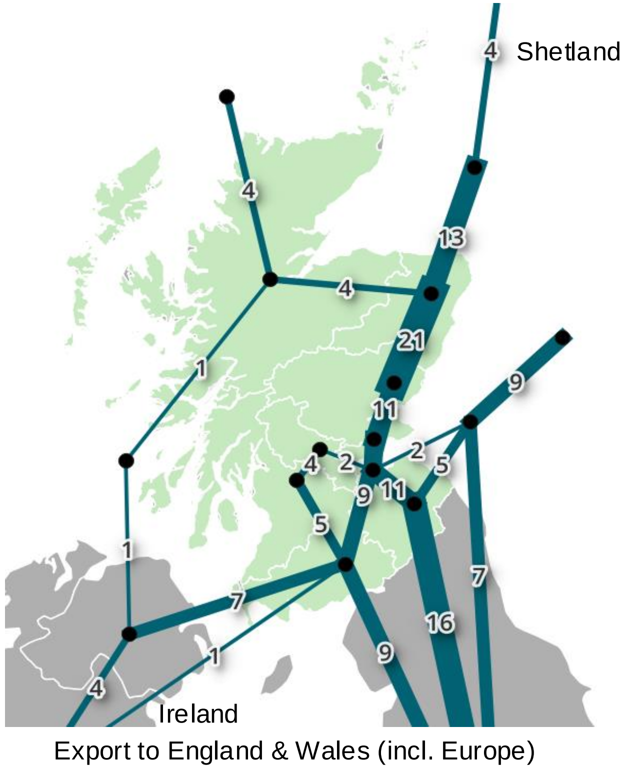


Guidehouse

[1]*Graphs only show hydrogen supply resources (e.g., green and blue hydrogen, storage, etc.) and not end-user demand (e.g., buildings, industry, etc.).*

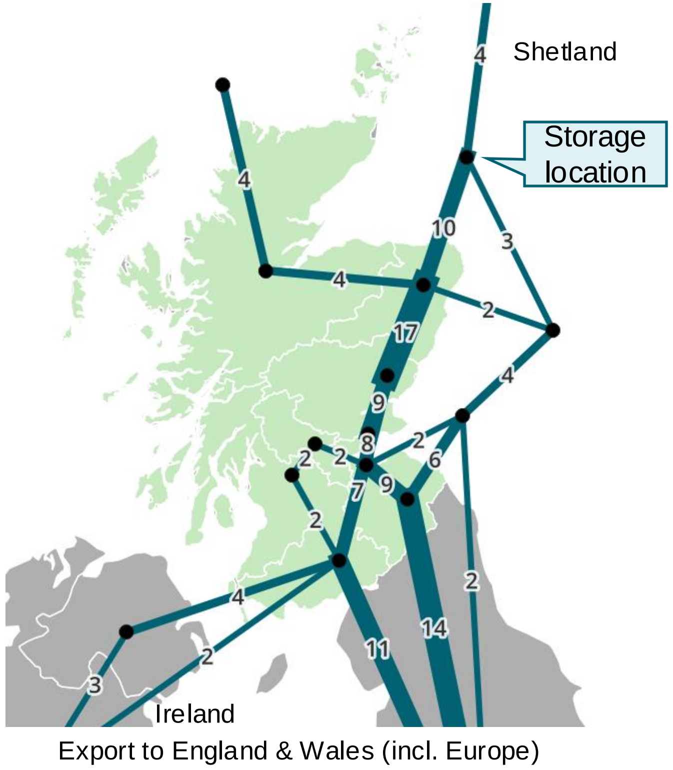
Hydrogen storage can help manage excess in production to provide a steadier export stream and reduce pipeline capacity by 28GW

Hydrogen transmission infrastructure capacities between modelled nodes (GW)



2045 – ST

Large transmission capacities are built out due to a less balanced system



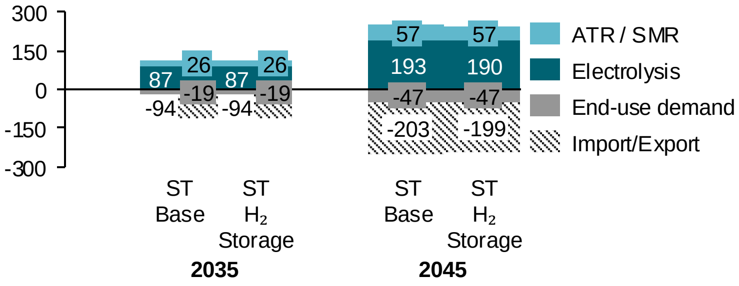
2045 – ST (H_2 Storage)

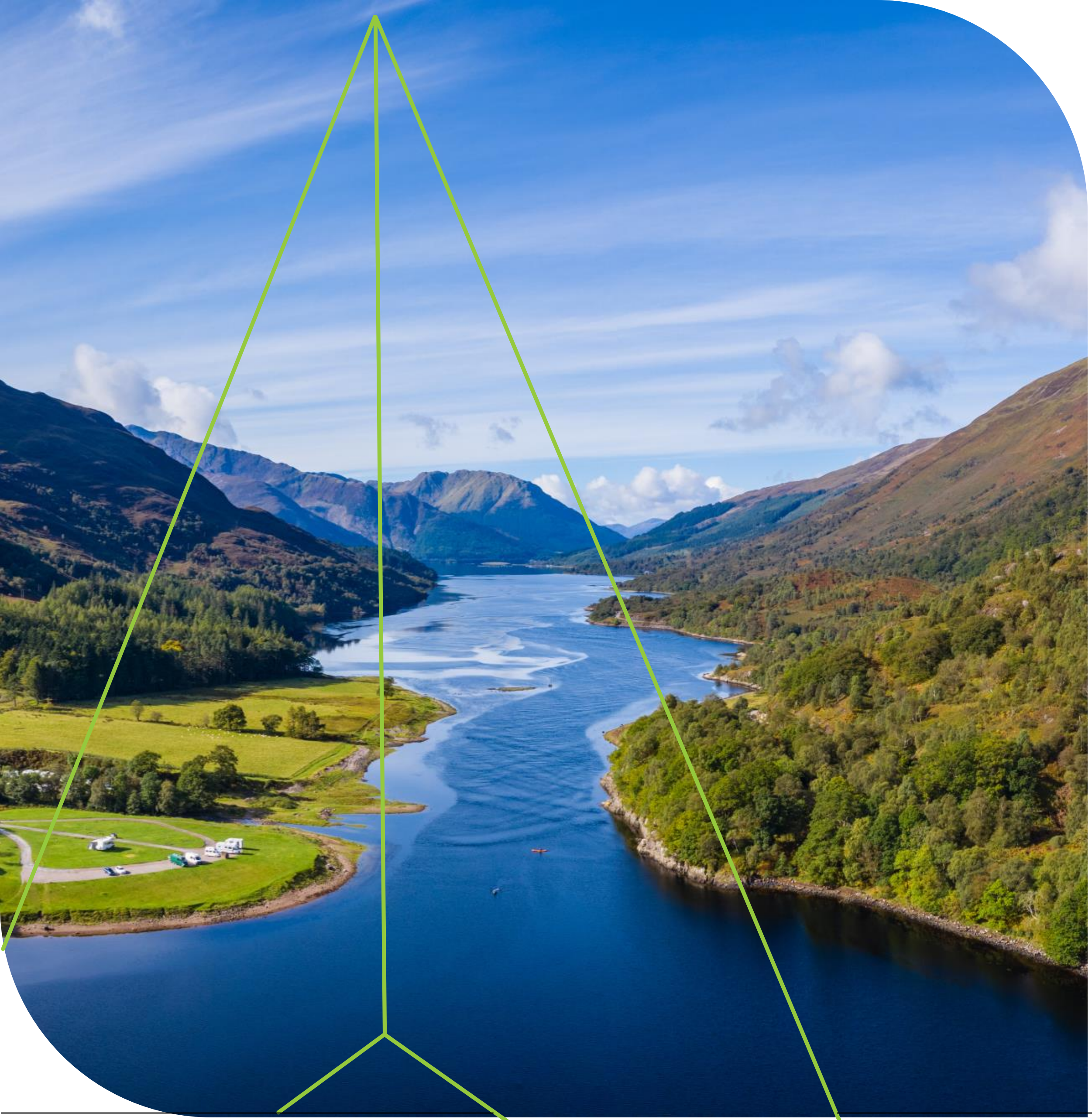
Smaller transmission capacities are required as the system is more balanced

Key Messages

- **13.5 GW of hydrogen storage** is being built in the North-Eastern offshore node, which is **greater** than the production capacity at this node, therefore allowing neighbouring regions such as the Eastern offshore node to utilise the storage. This results in new offshore hydrogen connections being built
- There is **less need** for the buildout of large infrastructure capacities due to a more balanced system and therefore the **same export potential can be met with 28 GW less infrastructure** in 2045. This provides minimum capital investment savings of **£800m** into hydrogen infrastructure

Hydrogen Export/Import, TWh_{H_2}





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Thank You