THE ROLE OF GAS AND GAS INFRASTRUCTURE IN SWEDISH DECARBONISATION PATHWAYS 2020-2045

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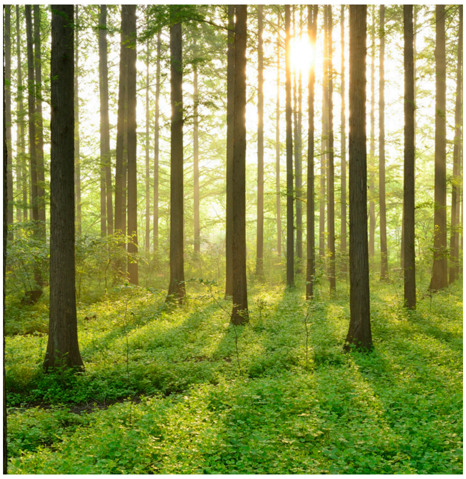

VÄTGASENS ROLL I ENERGI-
OCH KLIMATOMSTÄLLNINGEN

Energiforsk

The role of gas and gas infrastructure in Swedish decarbonisation pathways 2020-2045

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Swedish summary

Gas- och gasinfrastrukturens roll i ett klimatneutralt svenskt energisystem

Gasformiga energibärare som biogas och vätgas kan underlätta vägen till ett klimatneutralt svenskt energisystem, framför allt genom att ersätta fossila bränslen i sektorer med utsläpp som är svåra att reducera på andra sätt.

Syftet med den här studien är att utforska vilken roll förnybar och koldioxidsnål gas och gasinfrastruktur kan spela i ett klimatneutralt svenskt energisystem 2045.

Specifikt är målet att svara på följande frågor:

1. Vilken roll kan klodioxidsnåla och förnybara gaser spela i sektorer där det är särskilt svårt att minska utsläppen?
2. Vilka energikällor kommer användas för produktion av vätgas och biogas?
3. När, var, och hur mycket produktions- och distributionskapacitet behövs för att möta efterfrågan på gas i olika framtida scenarier?
4. Hur kommer el- och gasinfrastrukturen att användas och driftas när integreringen av olika delar av energisystemet ökar?

Två huvudscenarier för efterfrågan på gas är grunden för analysen

- **Major Role for Gas**, med hög efterfrågan på förnybar och koldioxidsnål gas. Detta är studiens centrala scenario.

- **Limited Role for Gas**, med väsentligt lägre efterfrågan på förnybar och koldioxidsnål gas

Båda scenarierna uppfyller målet om klimatneutralitet. Scenarierna har likheter - till exempel antas i båda scenarierna vätgas spela en roll i järn- och stålproduktion, lätta transporter elektrifieras till stor del och fjärrvärme spelar en fortsatt viktig roll - men det finns också väsentliga skillnader som beskrivs i figur ES.1. Utöver de två huvudscenarierna genomfördes också fem känslighetsanalyser av särskilt viktiga faktorer.

Figure ES-1: Jämförelse av studiens två huvudscenarier för efterfrågan på gas

	Major Role for Gas		Limited Role for Gas
	Koldioxidsnål och förnybar gas spelar en framträdande roll i alla sektorer, även om direkt elektrifiering dominerar i vissa användningsområden, som till exempel vägtransporter.		**Användningen av koldioxidsnål och förnybar gas begränsas till applikationer där inga rimliga alternativ idag finns.**
BUILDINGS	Uppvärmning av byggnader är i stort oförändrad, inklusive den låga andelen byggnader som använder gas för uppvärmning.	BUILDINGS	Uppvärmning av byggnader är i stort oförändrad, men den (låga) andelen byggnader som idag använder gas för uppvärmning övergår till värmepumpar.
TRANSPORT	Gas spelar en framträdande roll i all tung vägtransport, i sjöfart och flyg men en begränsad roll I lätta transporter.	TRANSPORT	Direkt elektrifiering dominerar vägtransporter, gas begränsas till tung och långväga vägtransport, sjöfart och flyg.
INDUSTRY	Gasanvändningen ökar markant, framför allt drivet av utvecklingen i stål- och kemisektorerna, men också i andra industrier.	INDUSTRY	Gasanvändningen ökar markant, i princip helt drivet av utvecklingen i stål- och kemisektorerna.

Robusta resultat från alla scenarier

Utsläppsminskningar i industri och transporter

- **Vätgas och biogas kan spela en nyckelroll i att minska växthusgasutsläppen i industri och transporter**. De intressentintervjuer som genomförts visar en ganska samstämmig bild av hur vissa sektorer kan eliminera sina utsläpp. Detta återspeglas i likheterna mellan projektets huvudscenarier, till exempel vad gäller och gasens roll i omställningen av järn och stål, tunga vägtransporter och sjöfart.

- **Vätgas och biogasanvändning kan koncentreras i regionala kluster.** Alla scenarier innehåller till exempel starkt ökad efterfrågan av vätgas i elprisområde SE1 (norra Sverige) drivet av utvecklingen inom järn- och stålproduktion. Hur regionala efterfrågekluster utvecklas påverkar behovet av infrastruktur för distribution av gas och el.

Elinfrastruktur

- **Elproduktionskapaciteten behöver öka väsentligt för att möta stigande efterfrågan på el.** Efterfrågan på el förväntas öka från dagens ca 130 TWh till mellan 241 TWh (Limited Role for Gas) och 253 TWh (Major Role for Gas) år 2045. En stor del av den ökade efterfrågan drivs av ny vätgasproduktion, I Major Role for Gas scenariot ökar produktionskapaciteten från ca 40 GW idag till ca 86 GW 2045. Största delen av ny kapacitet är vindkraft, som ökar från ca 9 GW idag till 53 GW 2045, och vindkraftsproduktionen ökar från 25 TWh idag till 180 TWh 2045.

- **Elnäten behöver stärkas kraftigt.** I synnerhet behöver det ske i sträckan mellan Danmark och SE2 för att föra el till efterfrågekluster i SE3 och SE4. Utbyggnaden av havsbaserad vindkraft, framför allt mellan 2030 och 2045, kommer också kräva ny överföringskapacitet.

- **Analysen indikerar inte en stor roll för vätgas för elproduktion eller -flexibilitet.** Givet tillgången på vattenkraft och möjligheter till elhandel i det nordiska energisystemet är detta resultat inte oväntat, men resultaten kan också påverkas av att flexibilitet är modellerad utifrån ett begränsat antal representativa säsongs- och topplastdagar

Produktion och distribution av vätgas

- **Ett nät för vätgas växer fram på sträckan SE3-SE1 i alla scenarier**. Detta kommer behövas för stål- och gruvindustri i SE1, och för hubbar för transport och industrier i och omkring städer i SE3.

- **Electrolyskapaciteten växer snabbt 2030-2045** i alla scenarier: som lägst till 4.9 GW_{H2} i Limited Role for Gas scenario upp till 12 GW_{H2} in ett scenario med låga kostnader för elektrolysörer. Den största tillväxten av elektrolyskapacitet sker I perioden 2035 - 2040, drivet av omställningen av järn- och stålindustrin.

- **Vätgasinfrastruktur är ett komplement till elnätet.** Alla scenarier och känslighetsanalyser visar 40% - 70% av elektrolyskapaciteten byggs i SE2. Detta är ett resultat av att utbyggnaden av el- och vätgasnäten kan kompletera varandra: genom lokalisering i SE2 kan elektrolysörerna både utnyttja billig elproduktion och avlasta flaskhalsar i elnätet.

- **Sverige har potential att exportera vätgas.** Sverige bör kunna producera vätgas till internationellt konkurrenskraftiga priser, även om denna aspekt inte har varit fokus för studien. Det indikerar att svenska produktionskapacitet för vätgas kan växa ytterligare för att möta efterfrågan i övriga Europa via Danmark, och/eller till Finland via SE.

- Vätgasproduktion från naturgas kan fortsatt att spela en roll, om än begränsad och i kombination med koldioxidavskiljning och -lagring. Efter 2030 kommer nya investeringar domineras av förnybar vätgas med elektrolys,

Produktion och distribution av biogas

- Analysen visar inte behov av ny överföringskapacitet mellan Danmark och Sverige. Även om biogasanvändningen ökar räcker existerande överföringsförbindelser.

- Svensk biogasproduktion ökar, och efter 2030 ersätter den gradvis importen från Danmark. 2045 överstiger den inhemska svenska produktionen importen.

Åtgärdsmöjligheter

Scenarioanalysen identifierar flera åtgärder som skulle accelerera en positiv utveckling och som kan genomföras så snart möjligt:

- Säkerställ att marknadsutformningen ger nödvändiga förutsättningar för energiföretagen att finansiera utbyggnad av infrastruktur för både tillförsel och distribution av energi.

- Utveckling och test av marknadsutformning kan lämpligen göras i regulatoriska sandlådor före allmän implementering.

- Sätt tydliga mål och strategier för vätgas, havsbaserad vind, och biogas. Sveriges strategier bör utvecklas i samklang med EU:s mål kring dessa tekniker och energibärare.

- Samplanera el- och gasinfrastrukturen genom att identifiera prioriterade el- och gasnätsförstärkningar, potentiella synergier mellan el- och gasnäten, och möjligheter till proaktiv nätutbyggnad.

- Skapa nya finansieringsmodeller för marknaden att investeringar i ny vätgasinfrastruktur.

- Öka kunskapen kring vätgasens framtida möjligheter att balansera elsystemet genom lagring och flexibel vätgasproduktion.

Keywords

Gasinfrastruktur, biogas, vätgas, förnybar gas, klimatvänlig gas, klimatomställning, energiomställning , sektorkoppling, avkarbonisering, samhällsutveckling, färdplan

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Executive Summary

Analysing the future role of gas in a climate neutral Swedish energy system

Sweden has set ambitious climate and energy targets to decarbonise its economy and energy system, and to achieve net-zero carbon emissions by 2045. To date, Sweden has already made significant progress in decarbonising the energy system, with much of its electricity and heating supply mix already made up of low-carbon and renewable energy.

Low-carbon and renewable gases like green hydrogen and biomethane – and their derivatives – have significant potential to play an enhanced role in the decarbonisation of the Swedish energy system, displacing fossil fuels from what would otherwise be hard-to-abate sectors. In this context, **the objective of this study is to explore the role of renewable and low-carbon gas, and gas infrastructure, in a future climate-neutral Swedish energy system up to 2045.** More specifically, this report aims to answer the following questions:

1. What role can low-carbon and renewable gases play in decarbonising hard-to-abate sectors and the Swedish energy system?
2. Which energy sources will be used to supply future demand for hydrogen and methane?
3. When, where and how much gas supply capacity and transmission infrastructure is needed to meet future energy demand in various visions of the future?
4. How will electricity and gas infrastructure be operated as the energy system becomes increasing integrated to meet future demand?

Two energy demand scenarios, modelling energy supply and infrastructure

To explore the role of gas supply and gas infrastructure, we modelled the development of electricity, hydrogen and methane supply capacity, and associated interconnection infrastructure, for an integrated energy system made of Swedish regions and neighbouring regions.

This study focuses on two 2020-2045 demand scenarios; **Major Role for Gas**, a scenario in which renewable and low-carbon gas play a prominent role in decarbonising energy demand for building heat, transport and industry and power generation, and **Limited Role for Gas**, a scenario in which renewable and low-carbon gas play a more limited role. Both scenarios share similarities that reflect accepted and well understood decarbonisation approaches for several sub-sectors (e.g., adoption of hydrogen-based direct reduction in steelmaking, electrification of light-duty road transport, the continuing role of district heating in buildings etc.). Nevertheless, there are some key differences:

- In **transport**, Major Role for Gas assumes biomethane and hydrogen play a major role in heavy road transport and shipping, while Limited Role for Gas assumes their role is limited.
- In **industry**, while hydrogen features heavily in both scenarios, biomethane plays a very small role in Limited Role for Gas.
- In **building heat**, Major Role for Gas assumes the small share of buildings using gas today continue to use gas in the future, while Limited Role for Gas assumes these buildings adopt electric heat pumps.

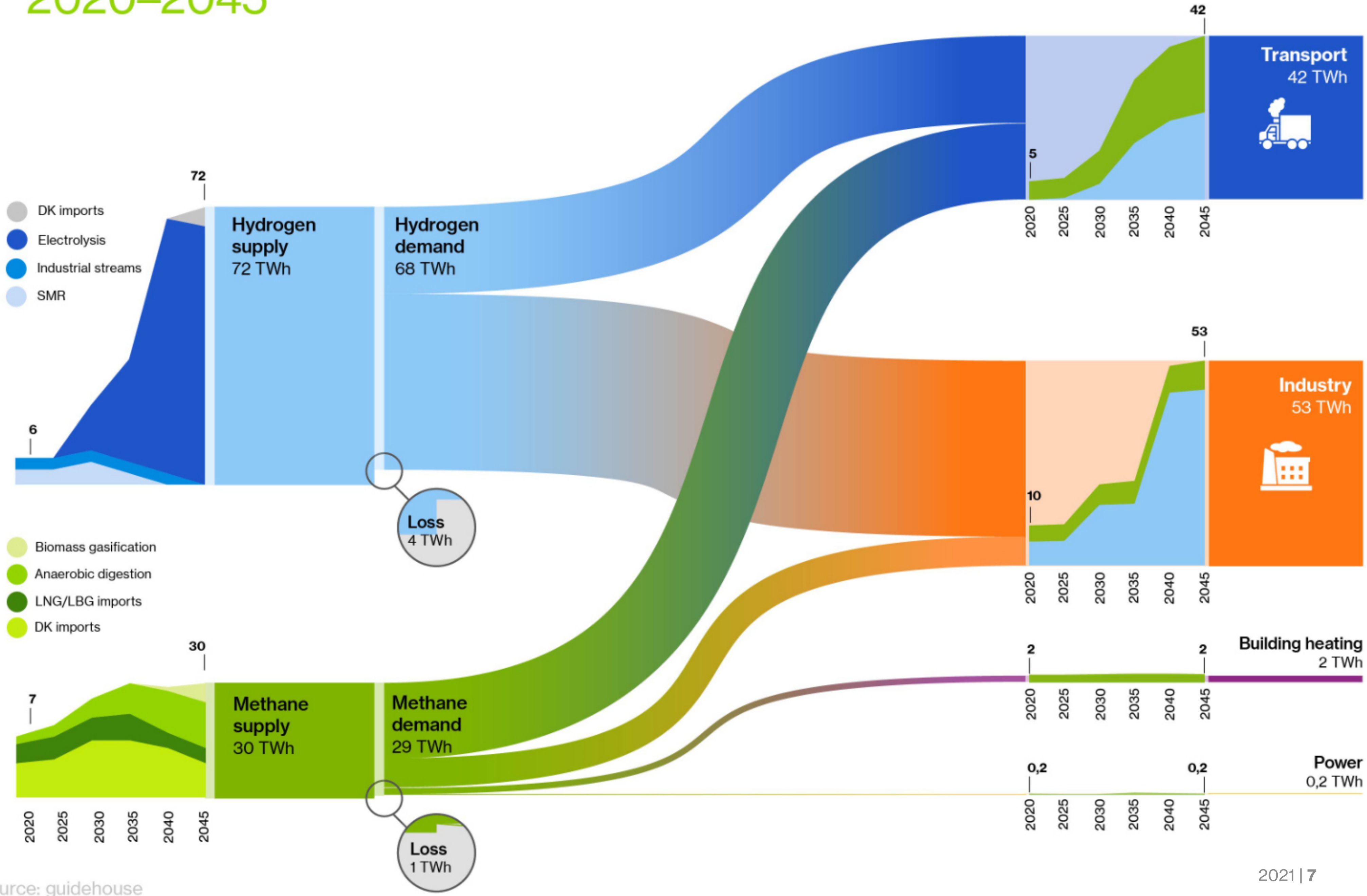
Our objective with these energy demand scenarios is not to identify the best or most likely decarbonisation pathway for the entire energy system; rather, to explore the role of gas supply and gas infrastructure in enabling the decarbonisation of the energy system.

To explore in detail the development of the energy system from today to 2045, this report adopts the Major Role for Gas scenario as the main central scenario for analysis. Later in this report, we also then compare the development of the Swedish energy system based on the second scenario, Limited Role for Gas, as well as based on four alternative sensitivity scenarios. This comparison of scenarios focuses particularly on the impacts and implications for gas supply and gas infrastructure.

Figure ES-1 – Description of demand scenario hypotheses

	Major Role for Gas	Limited Role for Gas
	Low-carbon and renewable gas plays a prominent role in all demand sectors. In some sectors, such as road transport, direct electrification plays the dominant role.	**The use of low-carbon and renewable gas is not widespread and is limited to sectors where no reasonable alternative exists**
BUILDINGS	The building heating energy mix remains largely unchanged, including the small share of buildings relying on gas for heating.	The building heating energy mix remains largely unchanged, however, the small share of buildings relying on gas adopt heat pumps.
TRANSPORT	Gas plays significant role in all types of heavy transport; road, shipping, and aviation, but a limited role in light duty transport.	Dominant role for electrification in road transport, while gas is limited to heavy, long-distance road transport, shipping and aviation.
INDUSTRY	Gas volumes increase significantly, largely driven by the Steel and Chemicals sectors, but also across other industries.	Gas volumes increase significantly, almost exclusively driven by in the Steel and Chemicals sectors.

Gas supply and demand in Sweden, Major Role for Gas
2020–2045



Source: guidehouse

Significant build-out of electricity and gas infrastructure is expected in all scenarios

In all of the scenarios and sensitivities analysed, the Swedish energy system will require an unprecedented scale-up of electricity, hydrogen, and methane supply infrastructure. The magnitude of this buildout will drastically transform the Swedish energy system and will perhaps be one of Sweden's largest infrastructure undertakings of all time.

Across all these scenarios and sensitivities, several common themes and insights emerged:

Decarbonisation of energy demand

- **Hydrogen and biomethane will play a key role in the decarbonisation of industry and transport.** All major Swedish energy stakeholders expect to see a future in which hydrogen and biomethane play a key in decarbonising energy demand. Our stakeholder consultation process – gathering input from key demand sectors like steel, mining, heavy road and shipping – reinforced this vision of the future. This vision is reflected in the similarities across our two demand scenarios: for example, with the adoption of hydrogen-based direct reduction in steelmaking, or the role of biomethane and hydrogen in heavy road transport and shipping.
- **Hydrogen and biomethane adoption will lead to regional demand clusters.** The adoption of hydrogen and biomethane across industry and transport will lead to the development of regional clusters of gas demand across Sweden. In the north of country, the decarbonisation of the steel sector will lead to the development of a large hydrogen cluster in SE1. Since many related pilot projects are already underway in Norbotten, all our scenarios and sensitivities assume this hydrogen cluster will develop in the future. Transport hubs and industries around major cities will also lead to hydrogen clusters developing in SE3 and SE4. From a biomethane perspective, the adoption of biomethane in heavy road transport and shipping also leads to the development of transport clusters in SE3 and SE4. The location of these gas demand cluster across Sweden will have an impact on the buildout of hydrogen and biomethane supply capacity and interconnection infrastructure.

Electricity supply capacity and infrastructure

- **Electricity supply capacity is forecasted to increase significantly to serve demand.** All our demand scenarios forecast a significant increase in electricity demand. The Major Role for Gas scenario forecasts an almost doubling in demand from 130 to 253 TWh, while the Limited Role for Gas scenario forecasts a slightly more moderate increase to 241 TWh. In both cases, much of this increase in electricity demand is associated with demand for hydrogen production. Whether one scenario or the other, this increase in electricity demand will require a significant scale up in electricity supply capacity. In the Major Role for Gas scenario, generation capacity increases from 40 GW today to 86 GW by 2045. Most of the increase in capacity is associated with onshore and offshore wind developments. Combined, wind capacity increases from 9 GW today to 53 GW by 2045, resulting in wind electricity production increasing from 25 TWh today to 180 TWh by 2045.
- **A strong buildout of electricity interconnection infrastructure will be required.** In line with the buildout of electricity supply capacity, strengthening of electricity interconnection capacity between Swedish regions, as well as between Swedish and neighboring regions will also be required. This buildout in infrastructure will occur largely along the SE2-SE4 corridor, delivering electricity from SE2 – a region with high electricity generation capacity – to demand centers in the south in SE3 and SE4. Significant interconnection infrastructure is also required to accommodate increasing shares of offshore wind capacity, as it scales rapidly from 2030 to 2045 in SE4 and SE3.

- **Our analysis does not find a major role for hydrogen in energy supply or flexibility.** Our findings do not show a role for hydrogen in the power sector. This finding is not unexpected given the context of the Swedish power system, being at the centre of a highly interconnected Nordic electricity grid and with large availability of hydro reservoir. Combined, these features give the Swedish power grid a high degree of flexibility[1].

Hydrogen supply capacity and infrastructure

- **A regional hydrogen backbone will emerge along the SE3-SE1 corridor.** In all scenarios and sensitivities, our analysis shows the build out of hydrogen interconnection infrastructure between SE1 and SE3. This backbone supply hydrogen to demand clusters at both ends; in SE1, where the steel and mining industry clusters will develop, and in SE3, where smaller industry and transport hubs develop in and around major cities.
- **Electrolyser capacity will scale rapidly from 2030 to 2045.** All scenarios and sensitivities show significant growth in electrolyser capacity by 2045 – ranging from as low as 4.9 GW_{H2} in the Limited Role for Gas scenario to as high as 12 GW_{H2} in one of the sensitivity scenarios analysed, the Low Electrolyser Costs sensitivity. Most growth in electrolyser capacity is forecasted from 2035 to 2040, when most of the decarbonisation of the steel sector is expected.
- **Hydrogen infrastructure complements the electricity grid.** All scenarios and sensitivities consistently show a significant share of electrolyser capacity will be installed in SE2. The siting of electrolysers in SE2 is a strategic decision. Electrolysers are sited strategically in SE2 to utilise an oversupply of electricity generation and to release bottlenecks along the SE2-SE3 corridor. With the buildout of electrolysers in SE2, SE2 is positioned as a hydrogen production hub serving demand for hydrogen in SE1 and SE3. The siting of electrolysers in SE2 illustrates how hydrogen and electricity networks can play complementary roles.
- **Sweden has the potential to act as a hydrogen exporter to neighbouring regions.** While this report did not explicitly explore the role of Sweden as an exporter of hydrogen, our analysis shows that nearly all hydrogen demand in Sweden will be supplied by domestic hydrogen production. This demonstrates that hydrogen production in Sweden is cost-competitive with hydrogen from neighbouring regions and that Swedish hydrogen could potentially be exported to mainland Europe via Denmark (DK), or Finland via SE1.
- **Hydrogen production via SMR will continue to play a role.** This study shows that, while limited, new SMR capacity will continue to be deployed until 2030. This finding is consistent across all scenarios and sensitivities. Post-2030, new investments will steer predominantly towards green hydrogen via electrolysis. Nonetheless, existing already paid-for blue hydrogen installations will continue to be operational in the future with CCS retrofits. Hydrogen production via SMR+CCS has the potential to become a source of negative emissions if the methane used in the production process is biomethane rather than natural gas. This is relevant given the ambition of Nordion Energi to develop a 100% renewable methane grid.

[1] This finding may be driven by the temporal granularity of our modelling methodology. Our analysis uses five (5) representative days to model the hourly dispatch of electricity supply – four seasonal days and a winter peak day. One of the challenges of this approach is that with extreme weather events becoming more frequent, representative days become less useful. In contrast, an analysis considering all 8760 hours of the year would better capture extreme weather events and their impact on the power system, potentially identifying a role for hydrogen in power flexibility.

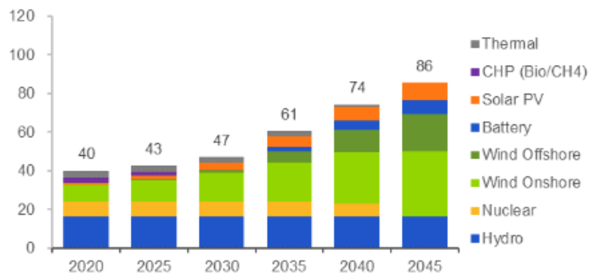
Methane supply capacity and infrastructure

- **Future expansion of the existing methane interconnection from Denmark to SE3 will not be required.** Neither the Major Role for Gas scenario nor the Limited Role for Gas scenario show the need for additional methane interconnection capacity from DK. While methane volumes flowing through the grid will continue to ramp up until 2030, expansion of the existing interconnection will not be required because the grid still has sufficient headroom available for future growth. Further, our analysis shows that beyond 2030, domestic capacity of anaerobic digestion (AD) and biomass gasification will ramp up.
- **Domestic methane production will scale up over time.** Our scenarios show that AD supply capacity will drastically ramp up – largely in SE3 – beginning in 2030. Over time, methane supply from AD will increasingly displace volumes of methane imports from DK. By 2045, methane volumes from domestic supply will be greater than import volumes from DK. In the Major Role for Gas scenario, the ramp up in AD capacity will be complemented by a ramp up in biomass gasification capacity.

To explore results at a more granular level, this section zooms-in on results for the Major Role for Gas scenario. This section begins by first exploring the scale up of electricity, hydrogen, and methane supply capacity from 2020 to 2045, and then presents a snapshot of the future state of energy infrastructure across Sweden in 2045.

Figure ES-2 – Electricity, hydrogen and methane supply capacity, major role for gas scenario

Electricity Supply Capacity (GW)



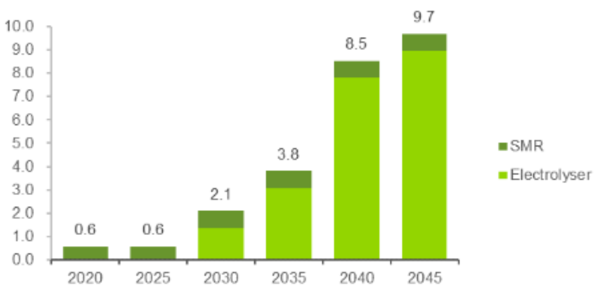
Electricity Supply Capacity Development

Electricity supply capacity increases 2x from 40 GW today to 86 GW by 2045[1].

Most of the increase in generation capacity occurs after 2030, primarily from growth in offshore and onshore wind capacity.

This buildout of generation capacity is driven by an almost doubling of electricity demand, which is in-turn largely driven by demand for hydrogen.

Hydrogen Supply Capacity (GW)



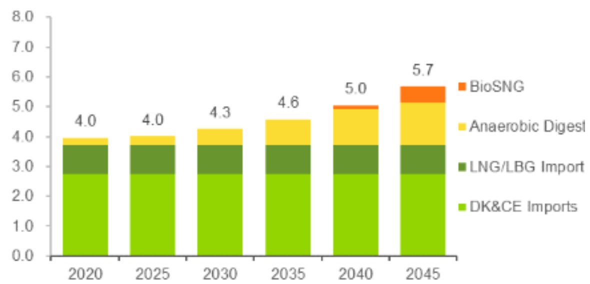
Hydrogen Supply Capacity Development

Hydrogen supply capacity increases from 550 MW_{H2} today – exclusively from steam methane reforming (SMR) – to 9.7 GW_{H2} by 2045 – largely made up of electrolysers.

Buildout of electrolyser capacity begins in 2030, and largely scales up in line with hydrogen demand from industry, increasing to 9.0 GW_{H2} by 2045, equivalent to 12.6 GW_{Elec}.

SMR capacity increases slightly from 550 MW to 700 MW_{H2}.

Methane Supply Capacity (GW)



Methane Supply Capacity Development

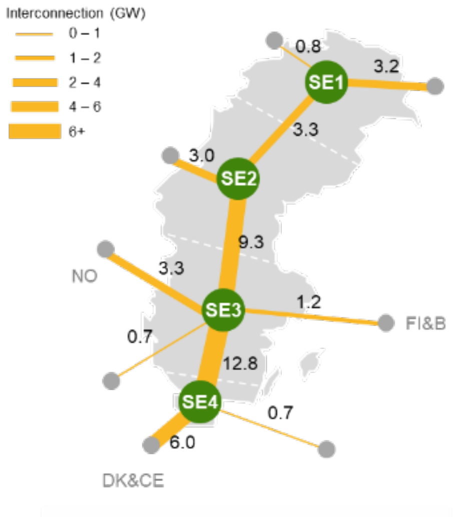
Import capacity from Denmark does not expand remaining at current capacity levels of 2.8 GW.

Domestic supply capacity from AD and bioSNG scales significantly after 2030. AD capacity grows to 1.4 GW by 2045, while bioSNG grows to 0.5 GW.

[2] In this study, a baseline of new electricity generation capacity is exogenously defined based on the Ten Year National Development Plan's National Trends scenario (TYNDP NT). Our analysis shows that in addition to the TYNDP NT plans for new capacity, new onshore and offshore wind capacity will be required. Beyond TYNDP levels, our analysis does not trigger additional solar PV or storage capacity.

Figure ES-3 – Energy infrastructure development in 2045, Major Role for Gas scenario

Electricity Infrastructure Map



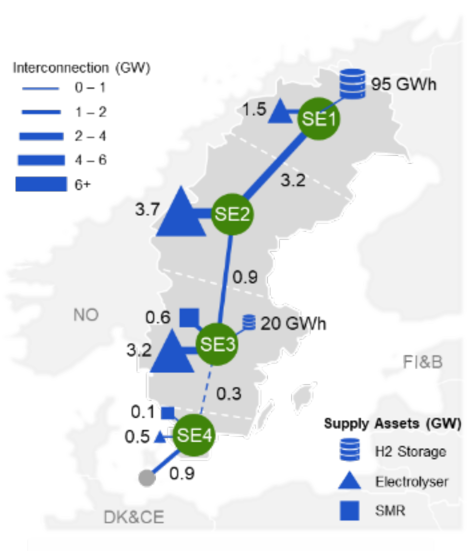
Electricity Infrastructure Development

By 2045, interconnection capacities across most of the Swedish electricity network and neighboring regions have expanded.

The backbone of the Swedish electricity grid, the SE-to-SE4 corridor, sees a large-scale buildout of interconnection capacity, with electricity supply continuing to flow south towards the major population centers.

The strengthening of the electricity grid is also driven by the need to accommodate increasing shares of onshore and offshore wind capacity, primarily in SE3 and SE4.

Hydrogen Infrastructure Map



Hydrogen Infrastructure Development

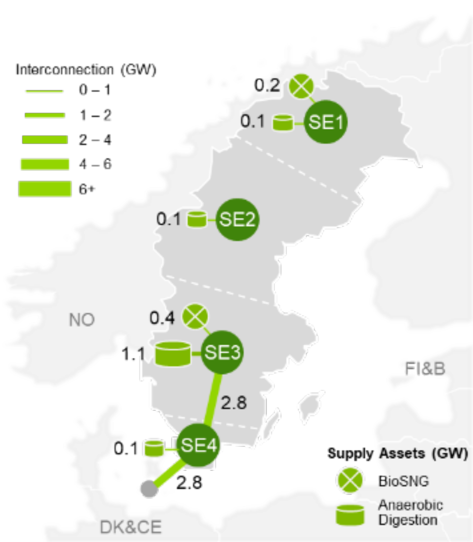
By 2045, we see the emergence of a regional hydrogen infrastructure backbone along the SE3-SE1 corridor serving hydrogen demand clusters at both ends in SE1 and SE3. Hydrogen storage will be needed in both regions to balance supply and demand.

The largest share of electrolyser capacity is located in SE2 as it serves as a hub of hydrogen production for its neighboring regions.

There is more limited development of infrastructure in the south, from DK to SE3; in particular a weak interconnection linking SE4 and SE3. This weak connection may more likely materialise as a local hydrogen network, rather than a regional transmission interconnection.

Note: A **dotted line** is used to denote *weak* interconnections (<0.5 GW) and the underlying uncertainty around their development.

Methane Infrastructure Map



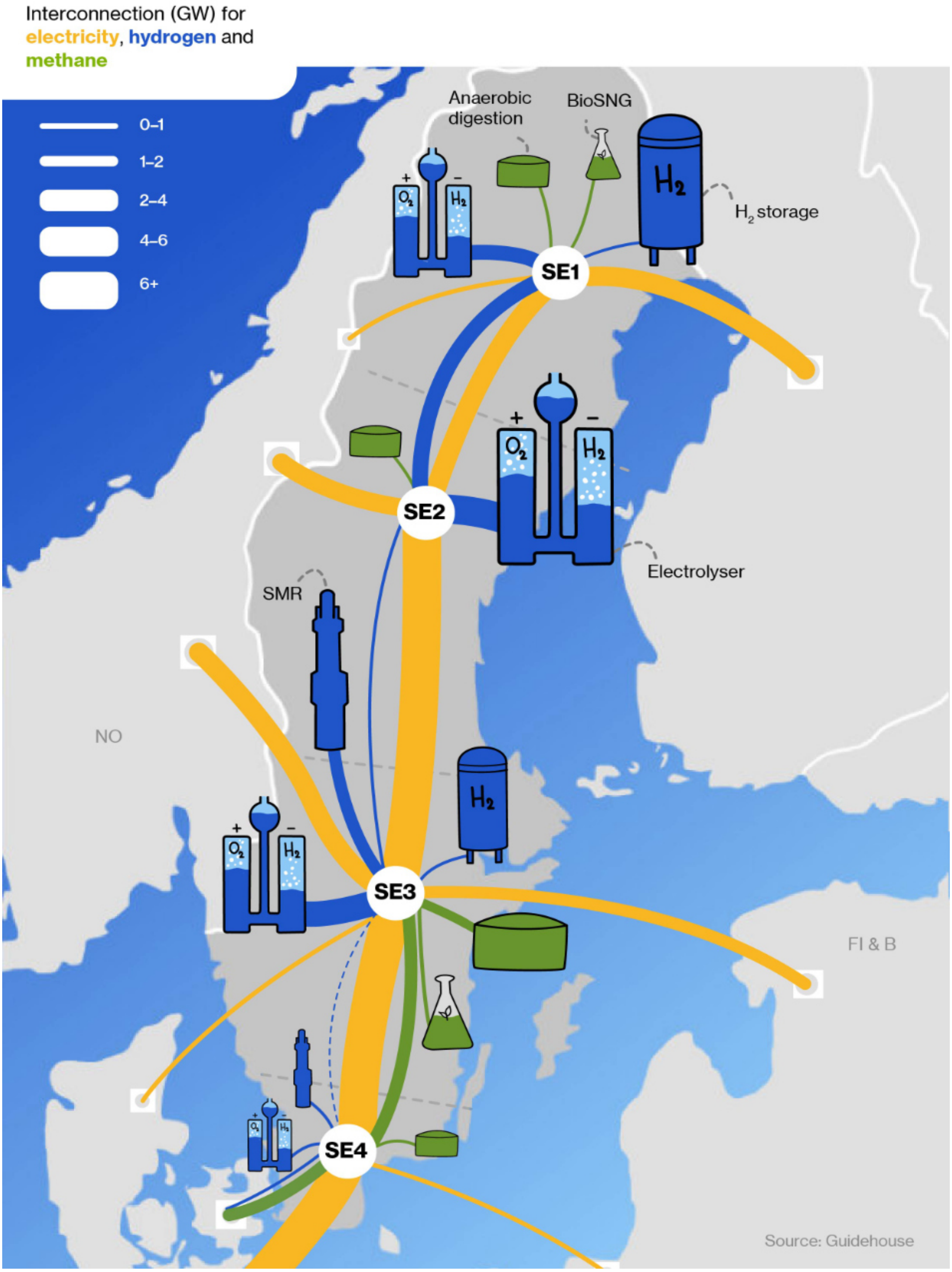
Methane Infrastructure Development

By 2045, no expansion of the existing interconnection from DK to SE3 has developed. Most methane demand in the south of the country continues to be met by imports from DK as there is still sufficient headroom available in the existing gas interconnection.

Over time, domestic methane production scales up and partially displaces methane imports from DK. Anaerobic digestion and biomass gasification supply capacity grows in SE3, as well as in areas not served by the gas system and where cost-effective feedstock is available.

Note: Map not drawn to reality. Region labels are drawn at the geographic centers of each region, rather than at the real location of the gas network.

Energy infrastructure across Sweden | 2045



Sensitivity analysis stress-test results, but reinforce the role of gas infrastructure

As with any analysis attempting to model a future integrated energy system, results are naturally subject to significant uncertainty. To stress-test the role played by gas infrastructure we explored the impact of alternative demand scenarios, as well as pathway uncertainties and challenges on gas supply and infrastructure.

While the results of these stress-tests lead to different sets of results, several elements remain consistent and unchanged. Our results show that in all of these alternative scenarios, decarbonising the Swedish energy system will require a large scale-up of both renewable electricity and hydrogen supply. This scale of hydrogen supply capacity will, in-turn, lead to significant development of hydrogen infrastructure, particularly in the north of Sweden.

Figure ES-4 Sensitivity Analysis Results, Inputs Changes and Results

	Input Changes	Impact on Results
1. Low H_2 Import Costs	Explores the impact of **lower hydrogen imports** compared to the main scenarios.	**A full hydrogen backbone develops from DK to SE1.** A large share of hydrogen demand is met by imports with hydrogen transported from south to north.
2. Low H_2 Infrastructure Costs	Explores the impact of **lower hydrogen infrastructure costs** compared to the main scenarios.	**Lower infrastructure costs have a minor impact on results.** There is a very subtle increase in hydrogen interconnection capacity. The development of hydrogen infrastructure across Sweden remains
3. Low Electrolyser Costs	Explores the impact of **low electrolyser costs** compared to the main scenarios.	**Lower electrolyser costs lead to an increase in the buildout of electrolyser capacity across most regions.** This, in turn, leads to a lesser need for interconnection capacity across some regions, as more hydrogen production occurs on-site.
4. Extended Nuclear Lifetime	Explores the impact of **extending the life of the nuclear fleet**, so that it stays online beyond 2045, vs. coming offline in 2040 and 2045 in the main scenarios	**The availability of the nuclear fleet leads to additional electrolyser capacity in SE3.** The development of hydrogen infrastructure is largely consistent. However, the abundance of electricity supply in SE3 shifts some electrolyser capacity, initially placed in SE2, south to SE3.
5. High Electricity & H_2 Demand	Explores the impact of **electricity and hydrogen demand forecasts** higher compared to the main scenarios.	**Higher hydrogen demand leads to increased development of hydrogen infrastructure.** Electrolyser capacity and hydrogen interconnections both increase as demand increases. A stronger backbone of hydrogen infrastructure develops across north to south.

Sweden may have a role to play as a hydrogen exporter to other countries

This study did not set out to explore all possible outcomes for the Swedish energy system. One of these outcomes is the potential for Sweden to act as a hydrogen exporter to neighbouring countries. This potential was not explored because our approach focused on quantifying hydrogen across Swedish regions, rather than in neighbouring regions. As a result, our findings do not explicitly address whether Swedish hydrogen supply capacity and infrastructure could potentially supply and transport hydrogen to other regions. Nevertheless, the findings of this study can provide insights on how some of these scenarios could unfold. Two hypothetical scenarios are of most interest:

- **Sweden as a Hydrogen Exporter:** Could Sweden play a role as an exporter of hydrogen to mainland Europe via Denmark?
- **Hydrogen Interconnection with Finland:** Could a hydrogen interconnection develop and connect Sweden and Finland to the north?

While these two scenarios are explored in isolation, they are not mutually exclusive and could unfold in parallel – with Sweden acting as a hydrogen exporter to mainland Europe via Denmark and to Finland via an SE1 interconnection in the north.

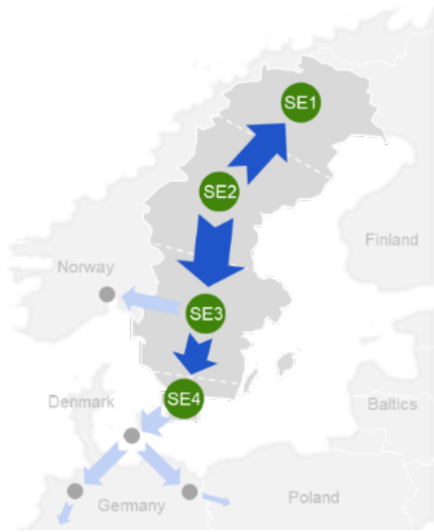
Sweden as a Hydrogen Exporter

Relevance of hypothetical scenario

- The role of Sweden as a "hydrogen export hub" supplying hydrogen to demand centers in Central/Western Europe has received recent interest.
- The low cost of electricity in northern Sweden, for example, has the potential to position Sweden as a cost-competitive source of hydrogen supply.

Insights from this study

- Our analysis shows that nearly all hydrogen demand in Sweden will be supplied by domestic green hydrogen production. Much of this hydrogen supply capacity will be concentrated in the north of the country.
- As most of this demand will be supplied via domestic hydrogen production rather than hydrogen imports via Denmark, this demonstrates that hydrogen production in Sweden can be cost-competitive with hydrogen available from a future European hydrogen backbone. With its lower cost of hydrogen production relative to neighboring regions, Sweden could scale up electrolyser capacity further in order to increase hydrogen production for exports.



Hydrogen Interconnection with Finland

Relevance of hypothetical scenario

- Roughly half of hydrogen demand in Sweden is located in the north of country, in SE1, where a steel and mining cluster will develop. The situation in Finland is not much different, with a large industrial cluster also located in the north of the country.
- With future hydrogen demand concentrated in the north of both countries, there is interest on whether a potential hydrogen interconnection between both countries could develop.

Insights from this study

- Our analysis shows that hydrogen supply, to meet demand in SE1, will likely be located where electricity supply capacity is abundant (e.g., SE2). The development of an interconnection to supply hydrogen demand in northern Finland would potentially result in additional electrolyser capacity being installed in SE2 as well as increased interconnection capacity to transport larger hydrogen volumes, first into SE1 and then into Finland.

- Availability of electricity supply in northern Finland is also highly relevant. An abundance of electricity supply would result in hydrogen being produced directly in Finland to serve demand in the north, potentially even transporting hydrogen to serve demand in Sweden.

Commercial and regulatory conditions must evolve to scale-up energy infrastructure

This analysis has developed a clear view of the magnitude of energy infrastructure development required across Sweden from today to 2045. At the core of this transformation, and with a critical responsibility for enabling and facilitating the decarbonisation of end-users, will be the electricity and gas transmission and distribution network companies. While electricity and gas TSOs and DSOs will play a key role, successfully managing this transformation will require all Swedish energy stakeholders to align on a common vision for decarbonising the energy system.

To ensure this vision becomes reality, there is an urgent need to create the right market conditions, and the right regulatory and operating environment. The ultimate objective will be to ensure that the underlying energy and climate policies, and the regulatory framework create attractive commercial and financial conditions for energy infrastructure companies to finance the scale up of energy supply and infrastructure capacity.

To this end, this report identifies a list of strategic actions and initiatives for all major Swedish energy stakeholders to implement in the near-term. This is an implementation roadmap that focuses on near-term actions from today to 2025, which should set the Swedish energy system on a net-zero trajectory. To develop this roadmap, Energiforsk and Guidehouse engaged a large number of energy stakeholders – including electricity and gas companies, public agencies, large end-user groups, industry associations and the Swedish government. We also reviewed three high-profile roadmaps developed by major Swedish energy stakeholders – Energigas Sverige, Svensk Vindenergi, and Fossilfritt Sverige – building on their extensive work and choosing to reinforce a selection of strategic actions and initiatives proposed by them.

The actions underpinning this roadmap are categorised into six distinct themes:

1. **Supporting the Development of the Electricity System.** The strengthening of the electricity system is foundational for the development of future hydrogen infrastructure and the production of green hydrogen. Several actions by the TSO and other stakeholders can ensure the electricity system is strengthened and can support the development of a hydrogen system: identifying priority electricity transmission lines and future electricity supply capacity, identifying opportunities for proactive grid investment in anticipatory infrastructure, developing an electricity-and-gas integrated "whole of system" planning approach, among others.

2. **Setting a Clear and Decisive Decarbonisation Direction.** There is a strong need for the government and policy makers to come out with a clear direction and path forward on several key energy supply and infrastructure topics: a made-in-Sweden view on the development of EU-level hydrogen regulations, an offshore wind strategy (on the heels of the EU's offshore wind strategy), and guidance to Sweden's major energy stakeholders with regards to long-term planning of low-carbon and renewable gas supply.

3. **Supporting the Transition of End-Users to Fossil-Free Energy.** For some sectors, the cost of transitioning to low-carbon and renewable gases can be passed-through to consumers. Some other sectors are more cost-sensitive and must remain cost-competitive in international markets. There's a clear need to better understand how different sectors will finance their decarbonisation, to identify what domestic and EU-level measures can be used to support their transition; among those, understanding how a carbon border adjustment mechanism in the EU-ETS could support local industries, or the application of the "green gas principle" to hydrogen use.

4. **Developing Attractive Market Conditions for Hydrogen and Biomethane Infrastructure Investments.** The scale up of hydrogen and biomethane supply capacity and infrastructure in the future will require having the right market conditions and financial levers in place. Stakeholders across the entire gas value chain – production, transmission, distribution, and consumers – have a role to play. There's a need to better understand what market measures (e.g., contract-for-differences or otherwise) can boost future demand and supply of hydrogen.

5. **Preparing for a Future Hydrogen System.** The development of a hydrogen system will require developing a better understanding of future potential network configurations and the design of hydrogen transmission and distribution networks. There's also a need to explore in more detail the medium-term role for blue hydrogen, the potential of gas-to-power technology in the electricity system, and the hydrogen storage needs and potential of a future hydrogen system.

6. **Creating an Enabling Regulatory Environment.** Energy regulators have a fundamental function in the value chain of large-scale energy infrastructure projects. However, as the energy system evolves, so should energy regulators. Several key actions can better position the Energy Markets Inspectorate for this role: among those, establishing electricity and hydrogen regulatory sandboxes to evaluate new, large-scale infrastructure projects, assessing its readiness to cope with and process a large pipeline of future projects, and gathering stakeholder inputs on hydrogen regulation and financing measures through a consultation process.

Short-term roadmap to scale-up energy supply and infrastructure | 2021–2025

2021 2022 2023 2024 2025

1. Supporting the Strengthening of the Electricity System

Several key actions are required by the TSO and other major stakeholders: identifying priority electricity transmission lines and future electricity supply capacity, engaging in proactive grid investment, developing an electricity-and-gas integrated "whole of system" planning approach, among others.

2. Setting a Clear and Decisive Decarbonisation Direction

Several key actions are required by the Government: a Swedish view on future EU hydrogen regulations, an offshore wind strategy, and guidance to Sweden's major energy stakeholders with regards to long-term planning of low-carbon and renewable gas supply.

3. Supporting the Transition of End-Users to Fossil-Free Energy

Several key actions are required by several major stakeholders: clear guidance on the application of certain market rules to the consumption of biomethane and hydrogen, a Swedish view on a potential carbon border adjustment mechanism (CBAM) and cross-industry collaboration on low carbon and renewable gas projects.

4. Developing Market Conditions for H_2 and BioCH4 Investments

Several key actions are required by public agencies: the implementation of proposals from the Biogas Market Inquiry to support the scale up of biomethane, identifying market measures to boost hydrogen demand and supply, and investigating hydrogen contracts-for-differences.

5. Preparing for a Future Hydrogen System

Several key actions are required by Nordion Energi, the Gas DSOs, and other major stakeholders: assessing future networks needs to meet hydrogen and biomethane demand, investigating the role of blue hydrogen and the need for hydrogen storage in Sweden, and analysing the potential of gas-to-power technologies in the Swedish electricity system.

6. Creating an Enabling Regulatory Environment

Several key actions are required by the Energy Markets Inspectorate: establishing electricity and hydrogen regulatory sandboxes to evaluate new, large-scale infrastructure projects, assessing its readiness to manage a large pipeline of future hydrogen and electricity projects, and conducting a consultation on hydrogen regulation and financing measures.

Chapter 1 Introduction

Sweden has set ambitious climate and energy targets to decarbonise its economy and energy system, and to achieve net-zero carbon emissions by 2045. To date, Sweden has already made significant progress in decarbonising the energy system, with much of its electricity and heating supply mix already made up of low-carbon and renewable energy.

Fossil fuels play a relatively small role in the Swedish energy system, compared to other European countries. A key remaining challenge for Sweden, as with most other world economies, will be the decarbonisation of transport and industry, where fossil fuels still play a large role today. This is precisely where low-carbon and renewable gases like green hydrogen and biomethane – as well as derivatives like bio-LPG, bio-LNG, among others – can play an enhanced role, displacing fossil fuels from what would otherwise be hard-to-abate sectors.

Currently, gas plays a relatively limited role in the Swedish energy system, delivering only a small proportion of the overall energy mix in Sweden. Nevertheless, all major Swedish energy stakeholders see a future in which hydrogen and biomethane play a key role. This shared vision is illustrated by past and current large-scale projects. For example, several major Swedish energy stakeholders are behind the development of HYBRIT[3], aiming to fully transform and decarbonise the steelmaking process. Similarly, Swedish energy stakeholders were also behind GoBiGas, Europe's largest demonstration project of biomass gasification technology. Most recently, momentum has also formed around the H_2 Green Steel venture, also backed by major Swedish stakeholders, looking to further speed up the decarbonisation of the steel industry. Despite this experience and momentum, the magnitude and significance of the future role for hydrogen and biomethane is still very much largely unexplored. This is the context of this study, and where it aims to add value.

The objective of this report is to explore the role and value of renewable and low-carbon gas, and gas infrastructure, in a future climate-neutral Swedish energy system up to 2045.

This report aims to answer the following questions:

- **What role can low-carbon and renewable gases play** in decarbonising hard-to-abate sectors and the Swedish energy system?
- **When, where and how much gas supply capacity and transmission infrastructure** is needed to meet future energy demand in various visions of the future?
- **How will electricity and gas infrastructure be operated** as the energy system becomes increasing integrated to meet future demand?
- **Which energy sources will be used** to supply future demand for hydrogen and methane?

[3] HYBRIT (Hydrogen Breakthrough Ironmaking Technology) is a joint venture jointly owned by SSAB, LKAB and Vattenfall. HYBRIT aims to decarbonise the steel value chain by replacing the use of coal/coke-based blast furnaces with a direct-reduction process for iron ore (HDRI) using fossil-free hydrogen.

By answering these questions, this report aims to inform Swedish stakeholders of decarbonisation pathways available in the Swedish energy system, the value and role of gas supply and gas infrastructure in alternative scenarios, and key strategic actions needed to set the Swedish energy system on pathway net-zero by 2045.

This report is divided in the following sections:

Section 1 (This section) introduced the study and its objectives, while **Section 1.1** provides background information on hydrogen and biomethane.

Section 2 Describes the current state of the Swedish energy system as well as the role played by gas supply and gas infrastructure and describes Sweden's main climate and energy policies.

Section 3 Describes our overall modelling methodology and approach, using our Low Carbon Pathways (LCP) model to optimise the decarbonisation of the Swedish electricity and gas system from today to 2045.

Section 4 Presents our two main demand scenarios of electricity, hydrogen, methane and heat demand until 2045: Major Role for Gas and Limited Role for Gas.

Section 5 and Section 6 Present the results of the pathway optimisation modelling using the Major Role for Gas scenario. We use the Major Role for Gas scenario as our central scenario to explore the role of gas supply and gas infrastructure in decarbonising the energy system:

- Section 5 presents the optimised buildout results of electricity, hydrogen and methane supply capacity, first at the national level and then for each individual Swedish region; and
- Section 6 presents the optimised infrastructure buildout results of electricity, hydrogen and methane transmission interconnections, beginning with a snapshot of energy infrastructure in 2020, fast forwarding to 2030, 2040 and ending with 2045.

Section 7 Explores the role of gas and gas infrastructure under the Limited Role for Gas scenario as well as several sensitivities and uncertainties applied to the Major Role for Gas scenario. This section also compares the total gas infrastructure investments required in the Major and Limited Role for Gas scenarios.

Section 8 Summarises key pathway takeaways and insights across all scenarios and sensitivities analysed; and

Section 9 Presents a strategic, action-oriented roadmap that aims to create attractive market and regulatory conditions that can enable investment in electricity, hydrogen and biomethane supply and infrastructure.

1.1 Background on Hydrogen and Biomethane

Hydrogen and biomethane will play pivotal roles in the decarbonisation of the Swedish gas system. In this report, the term hydrogen is generally used to refer to low-carbon, fossil-free, or green hydrogen. The terminology used to refer to different types of hydrogen is described below. Demand for any type of hydrogen – whether carbon-free or not – is simply referred to as hydrogen demand. Today, most hydrogen supply is not carbon-free and is produced via thermal conversion of natural gas, a process which produces emissions. The term methane is used to refer to both natural gas (CH4) and biomethane (bioCH4). Demand for any methane – including natural gas, biomethane, liquified natural gas (LNG) or biogas – is referred to as methane demand. Today, a significant share of methane demand is meet via natural gas imports from Denmark. In the future all methane supply will have to be fossil-free biomethane. Methane demand today is also met via liquified natural gas (LNG) imports and Swedish biogas.

Our analysis is focused on two hydrogen production technologies and two biomethane production technologies:

Hydrogen can be produced via steam methane reforming (SMR) and via electrolysis.

- Hydrogen production via **SMR** produces carbon emissions and is known as grey hydrogen. When SMR is paired with carbon capture and storage (CCS) most carbon emissions are eliminated, however some residual emissions remain. Hydrogen produced via SMR+CCS is known as blue hydrogen.
- Hydrogen production **via electrolysis** is mostly free of carbon emissions, however, a distinction regarding the source of electricity used in the electrolysis process is important. Hydrogen produced using electricity from renewable energy is completely emissions-free and is known as green hydrogen. Hydrogen produced using electricity from the grid – containing nuclear energy – is known as fossil-free hydrogen.

Biomethane can be produced via anaerobic digestion and via biomass gasification.

- **Anaerobic digestion** typically uses organic waste material as feedstock and produces biogas, which requires upgrading to produce biomethane.
- **Biomass gasification** uses solid feedstock to produce a synthetic gas (syngas), which is then followed by a methanation process to produce bio-syngas (or bioSNG).

Table 1 – Hydrogen and biomethane production technologies

Hydrogen		Biomethane	
Blue Hydrogen	**Green or Fossil-Free Hydrogen**	**Anaerobic Digestion**	**Biomass Gasification**
Blue hydrogen refers to hydrogen produced via steam methane reforming (SMR), which is based on a thermochemical conversion of natural gas. SMR is paired with carbon capture and storage (CCS) in order to significantly reduce carbon emissions.	**Green hydrogen** refers to hydrogen produced via electrolysis, a process which uses electricity to split water into hydrogen and oxygen. There are different types of electrolysers; alkaline electrolysers (AE), proton exchange membrane (PEM) and solid oxide electrolysis cells (SOECs). AE is currently the most mature and cost-effective technology.	**Anaerobic digestion** is a well-known and widely used biological process for converting biomass. or natural feedstock, into biogas in the absence of oxygen. Typical feedstocks for anaerobic digestion are wet organic waste materials such as manures, sewage sludge, food wastes as well as crops such as maize.	**Biomass gasification** refers to a process in which solid feedstock is heated in the presence of a reduced concentration atmosphere comprising air, oxygen or steam, to produce a synthetic gas (syngas). This syngas must then go through a methanation process to be 'cleaned' and converted into bio-syngas (bioSNG).

Two alternative hydrogen production methods are described below. Our analysis focused exclusively on hydrogen production via SMR and electrolysis and did not capture these technologies.

- **Auto-Thermal Reforming (ATR):** An alternative to hydrogen production via SMR is autothermal reforming (ATR). SMR is much more dominant than ATR. Unlike SMR, the ATR process requires an additional oxygen supply which can lead to additional emissions and costs if the oxygen is not supplied as a byproduct.
- **Bio-Hydrogen:** Another production method is biomass gasification, which involves the thermochemical (or bio-chemical) conversion of biomass resources or biomass waste to produce hydrogen. Hydrogen produced via biomass gasification is also referred to as bio-hydrogen. Due to relatively high biomass feedstock costs, bio-hydrogen is unlikely to play a role in hydrogen supply in the long-term.

An additional biomethane production technology is 'power-to-gas' biomethane, where hydrogen can be used as feedstock to produce synthetic methane. Synthetic methane can be produce based on the hydrogenation of carbon dioxide, using captured-CO_2 from anaerobic digestion plants and hydrogen from excess electricity. Power-to-gas biomethane is more costly and – given the feedstock and inputs needed – more limited in availability.

Hydrogen is traditionally transported and delivered in two ways: via pipelines and road transport.

- **Pipeline:** Nearly all hydrogen supply in Sweden is transported via pipeline. Local hydrogen grids in the west coast are used to supply hydrogen to large chemical and petrochemicals facilities.
- **Road transport:** In Sweden, only very small volumes of hydrogen are transported from production sites to end-users via road transport in compressed form. Road transport is a much more costly alternative because of constraints on the amount of volume that can be transported by trucks, as well as additional compression infrastructure required. Hydrogen can also be liquified in order to be stored or delivered.

There is very limited hydrogen infrastructure in operation today in Sweden. As a result, there is also limited technical and operational experience in the operation of hydrogen transmission and distribution networks. Most experience in hydrogen today is limited to handling of hydrogen in an industrial setting, with the chemical and petrochemical industries being the largest hydrogen consumers in Sweden and the most experienced. Safety procedures and standards in the production, transport, storage, and handling of hydrogen are known within industry, however, outside industry, safety procedures and standards are not as known. From a gas network perspective, safety procedures and standards exist for other gases – natural gas, biogas, LNG, CNG and LPG – however, they have not been explicitly developed for hydrogen. With the increasing attention on hydrogen, there is ongoing work both at the national level and at EU level to establish guidance for the production, transport, storage and general handling of hydrogen.

Chapter 2

The Swedish Energy System

2.2 The energy balance

Sweden has achieved significant progress in decarbonising its energy system. A large share of Sweden's primary energy supply mix is already dominated by low-carbon and renewable energy – with nuclear, bioenergy and hydropower combined, accounting for 71% of the total energy. Sweden's fossil fuel dependency has decreased significantly and only accounts for 21% of the energy mix, which is much lower compared to most other European countries. Also, unlike most European countries, natural gas accounts for a very small share of total energy supply, approximately 2%.

The electricity supply mix in Sweden is close to being 100% carbon-free, largely dominated by electricity generation from nuclear (39%) and hydro (39%). In recent years, wind capacity has scaled up significantly, becoming the third largest resource (12%). The remaining supply mix is made up mostly of CHP, and some solar. Sweden has been a net-exporter of electricity for the last decade, regularly exporting over 20 TWh to neighbouring regions, equivalent to more than 10% of electricity generation. In 2019, exports reached a high of 26 TWh in 2019, mainly due to a substantial increase in wind.

2.2 The role of gas supply and gas infrastructure today

2.2.1 Gas supply

Natural gas (and biomethane) accounts for only 2% of Sweden's energy mix. Natural gas infrastructure was first developed in Sweden in 1982, mainly in the Malmö-Gothenburg area as well as within Stockholm. While gas demand has fluctuated over time, a stable annual quantity of around 15 to 20 TWh of gas[4] has been consumed.

While the use of gas is quite limited at a national level, gas plays an important role for industrial sectors along the west coast, where it represents around 20% of the total primary energy supply. Industrial sectors – like the chemical and petrochemical industries – are the largest gas consumers in Sweden. In these sectors, large volumes of gas are used in the production of hydrogen. Hydrogen production amounts to c.6 TWh, of which roughly two-thirds is produced via gas reforming (~4 TWh) and one-third via residual gas stream from industrial processes (~2 TWh). Negligible amounts of hydrogen are produced via electrolysis. In addition to the chemicals and petrochemicals industry, the steel industry is also a major user of gas (primarily LNG and LPG), however, most of this gas demand is off-grid and not supplied via the gas network.

[4] (Energigas Sverige, 2019)

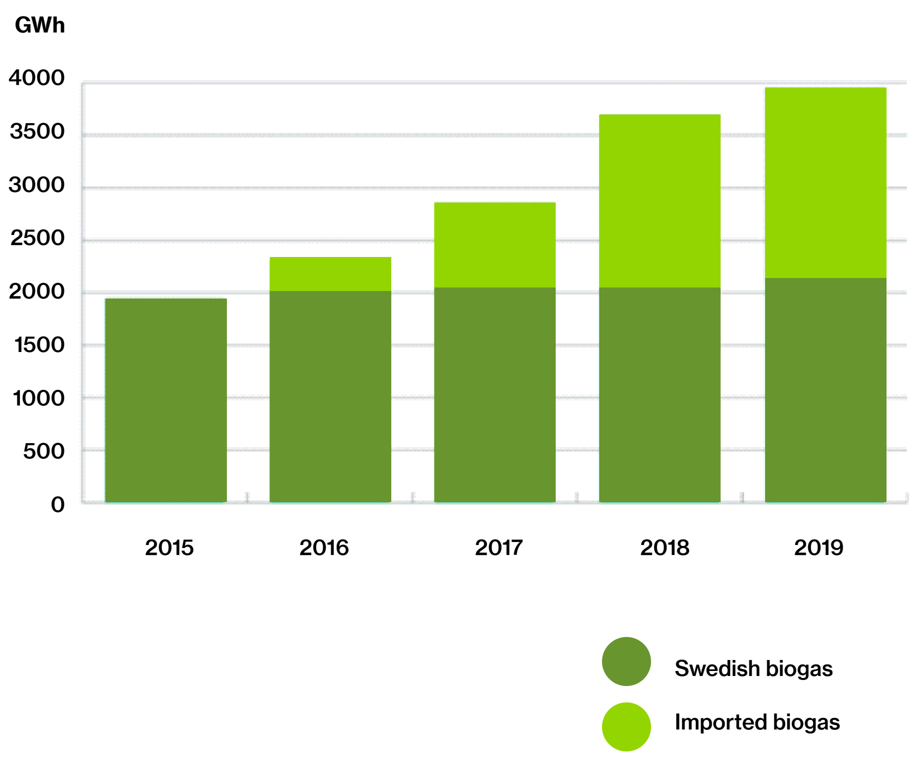
Outside industry, gas use is largely limited to heating generation, where gas demand is also significant. Among other uses:

- Non-heat gas demand in buildings for **water heating and cooking** is relatively minor.
- Gas use in **transport** – primarily limited to compressed biogas in bus-fleets and taxi-fleets – has historically been limited. Nevertheless, in recent years, there has been growth in demand for gas in heavy-road transport and shipping.
- Gas volumes used in **power generation** have also declined.

While most gas demand is supplied via imports from Denmark through the Dragör interconnection or via LNG terminal ports, some biogas is produced domestically. Annual Swedish biogas production is roughly 2 TWh, mainly produced in co-digestion plants (49% in 2019) using biowaste and residues, and in wastewater treatment plants (35%) using sewage sludge[11]. Across Sweden, there are a total of 280 biogas production plants, and some are connected to a number of smaller local and regional networks. The share of biomethane in gas imports from Denmark has increased significantly in recent years, reaching almost 2 TWh in 2019.[11] While a large part of the produced biogas is used locally and transported in trucks to filling stations, a total of 14 injection sites also inject biogas in the Stockholm and Western gas networks[11].

The shares of biogas injected into the grids have been increasing year after year. For example, the share of biogas in the transmission and distribution network along the west coast rose from 26% in 2019 to 33% in the first quarter of 2020. The share of biogas has reached an even higher level in the Stockholm network, accounting for 70 to 80%[11].

Figure 1 – Total biogas consumption in Sweden[11]



2.2.2 Gas infrastructure

Gas transmission and distribution grid

Sweden has a small gas infrastructure system compared to other European countries. The gas transmission grid is made up of 620 km of pipelines, stretching from Trelleborg to Stenungsund, while gas distribution grids consist of around 2,600 km of pipelines.[6] Most gas supply is imported from Denmark via the Dragör gas pipeline into Malmö.[7] The technical capacity of the entry point at the Dragör pipeline is 7.2 mcm/day, after the BalticPipe (BP) project is built in autumn 2022 – connecting Norway and Poland via Denmark – the maximum capacity in Dragör will decrease slightly to 6.9 mcm/day due to reduced pressures.

Out of the 290 municipalities in Sweden, 30 of them along the west and south coast have access to the gas system. It is not expected that the Swedish gas infrastructure will experience significant expansions, as no developments are currently in the planning[21].

A gas network also exists in Stockholm, operated by Gasnätet Stockholm, serving residential and commercial customers through a local gas network and gas stations through Stockholm's vehicle gas network.

There is very limited hydrogen infrastructure in operation today. Local grids supply hydrogen, mostly in and around Göteborg, to the petrochemical and refinery industries. Almost all hydrogen production occurs on-site or is delivered via these local grid. Very small volumes of hydrogen are transported from production sites to end-users via road transport in compressed form. In addition to hydrogen delivery via pipelines or in compressed form, hydrogen can also be liquified in order to be stored or delivered.

LNG terminals

In addition to transmission and distribution gas infrastructure, there are three LNG terminals not connected to the gas grid. One terminal is located on the west coast, in Lysekil, with a storage capacity of 30,000 m3. The second one is located in Nynäshamn, south of Stockholm, with a storage capacity of 20,000 m^3 [20]. These two terminals supply gas to refineries close by as well as to other industrial customers and municipalities via trucks. The Nynäshamn LNG terminal, in particular, supplies the gas network in Stockholm.

The third terminal is located at the Port of Gothenburg, and only recently started operations in 2018, supplying gas for shipping, industry and road transport[8]. There are plans to add four smaller LNG terminals: two in Gävle, one in Åhus, and another in Oxelösund. The Oxelösund LNG terminal will supply gas/biogas demand from SSAB's steel operations as they transition away from coal/coke-based production.

Gas storage

Sweden has no large gas storage sites. Seasonal variations are met using Danish storage facilities, namely Stenlille and Lille Torup facilities[20], and with line-packing flexibility services in the Swedish grid. One small storage facility in the southwest, near Skallen, is in operation and is used to meet short-term peak demand. This storage site is a Lined Rock Cavern (LRC) site with a limited total capacity of 8.8 mcm and a maximum withdrawal capacity in the range of 0.6-0.9 mcm/day[20].

[6] (Energimarknads inspektionen, 2012)

[7] (Ministry of Infrastructure, 2020)

[8] (Ministry of Infrastructure, 2020)

Figure 2 – Gas infrastructure in Sweden

Source: Energiforsk[9]

[9] Energiforsk (2015). Available here: https://energiforskmedia.blob.core.windows.net/media/22030/measuring-and-ensuring-the-gas-quality-of-the-swedish-gas-grid-energiforskrapport-2016-325.pdf

2.3 Swedish climate targets and policy overview

Sweden has set ambitious targets to decarbonise its economy and energy system and achieve net-zero carbon emissions by 2045. The Swedish Climate Law, signed by the Swedish Parliament in Jan-2018, set clear long-term emissions goals defining an emission reduction target of 85% by 2045 compared to 1990 levels. For the remaining 15% of emissions, the Climate Law defined that this could be achieved through a number of measures, including net removal by forests and land, through investments in other countries, and capture and storage of biogenic carbon dioxide[21]. The Climate Law also defined intermediate targets for 2030 and 2040. By 2030, emissions from sectors outside the EU's Emission Trading System (EU ETS) would be at least 63% lower compared to 1990 levels, and 75% lower in 2040[21].

The Climate Law also specified an emissions target for domestic transport, excluding aviation, whereby emissions must be at least 70% lower by 2030 compared to 2010 levels. Sweden has set a national objective to achieve a 100% renewable energy in electricity generation by 2040. This target does not imply a ban on new investments in nuclear energy nor a decision to stop existing nuclear energy generation beyond 2040. Sweden has also set an energy efficiency target, with a cross-sectoral target to reduce energy intensity by 50% between 2005 and 2030 – expressed as primary energy in relation to real GDP. This target does not include fuels used for non-energy purposes[10]. These four high-profile climate and energy targets are summarised below.

Table 2 – Summary of Swedish climate targets[22]

Target	Base year	2030	2040	2045
1. Greenhouse gas emissions reduction from sectors outside the EU ETS.	1990	63%	75%	85%
2. Emissions reduction in the national transport sector, excluding aviation	2010	70%		
3. Electricity generation from renewable sources			100%	
4. Improvement in energy efficiency	2005	50%		

As an EU Member State, these climate goals are also impacted by EU policies like the EU ETS, the Renewable Energy Directive, the Fuel Quality Directive, emissions requirements for new vehicles, among others. Sweden has also a set out a number of domestic cross-sectoral energy policies that, up to now, have supported the decarbonisation of the Swedish energy system. However, to deliver these long-term climate and energy goals, existing policies may not be sufficient, requiring new and stronger policies and sector-specific decarbonisation roadmaps. The table below gives an overview of current policies and measures in place aimed at achieving the 2030 climate targets.

[10] (Ministry of Infrastructure, 2020)

Table 3 - Summary of existing national energy policies and relevant activities[22]

CROSS-SECTOR	• Energy Tax and Carbon Tax • The Klimatklivet investment support
TRANSPORT	• Emissions reduction obligation for gasoline and diesel suppliers • Bonus-malus system for new light-duty vehicles • Carbon-based vehicle tax • Urban Environment Agreement • Eco-bonus system for shipping • Electrification commission • Two-wheel Electric Vehicle Premium and electric boat engines • Grant scheme for private charging infrastructure • Electric bus, electric truck and machinery incentive payments • Electric roads and rapid charging along major roads • Tax on air travel • Night trains abroad
INDUSTRY	• Energy Mapping Act • The Energisteget programme • The National Regional Fund Programme • The Industriklivet initiative
BUILDINGS	• National Board for Housing, Building and Planning (NBHBP) Energy performance standards • Energy Declarations for Buildings Act • Support for renovation and energy efficiency measures in rental housing • The renovation, conversion and extension tax deduction • Municipal energy and climate advisory services • The Sustainable Building Information Centre • The District Heating Act and the Price Dialogue • Waste Tax Act • Landfill Act • Tax on waste incineration
POWER	• The green certificate system • Investment support for grid-connected solar PV and hybrid solar electricity and heat systems • Tax deduction for solar PV and solar heating systems • Support for storage for self-generated electrical energy • Network charges exemptions • Tax reduction for microgeneration of renewable electricity • Reduced energy tax for microgenerators of renewable energy • Grid reinforcement loan scheme
AGRICULTURE & FORESTRY	• The 2014–2020 Rural Development Programme • Support scheme for biogas production

Lillgrund Wind Farm

Chapter 3

Modelling Methodology and Study Approach

3.1 Modelling methodology

To determine the cost-optimal way to decarbonise the Swedish energy system and analyse the development of gas supply and infrastructure, this study used Guidehouse's Low Carbon Pathways (LCP) model – Guidehouse's in-house energy system model. The LCP model optimises the build out of supply capacity, transmission interconnections, and storage assets to meet future energy demand, simulating the hourly dispatch of electricity, hydrogen, methane, and heat to meet energy demand.

The LCP model uses a nodal network to model an interconnected energy system, each node with its unique energy supply and demand, varying over time. We configured the LCP model to the Swedish energy system, dividing Sweden into regions corresponding to the four existing electricity bidding zones (SE1, SE2, SE3 and SE4), and 3 neighboring regions: Denmark and Central Europe (DK&CE), Finland & the Baltics (FI&B), and Norway (NO). All existing electricity and gas interconnections between regions are simulated in the model. The model also allows for existing interconnections to be expanded or for new ones – where applicable – to be constructed.

3.1.1 Applying our modelling methodology to demand scenarios

This study applies the LCP model to two key demand scenarios; Major Role for Gas, a scenario in which renewable and low-carbon gas play a prominent role in decarbonising energy demand for building heat, transport and industry, and Limited Role for Gas, a scenario in which renewable and low-carbon gas play a more limited role.

The major differences across these two scenarios are summarised here and are described in more detail in Section 4.1:

- In **transport**, the Major Role for Gas scenario assumes biomethane and hydrogen play a major role in heavy road transport and shipping, whereas the Limited Role for Gas assumes their role is limited.
- In **industry**, while hydrogen features heavily in both scenarios, biomethane plays a very small role in the Limited Role for Gas scenario.
- In **building heat**, the Major Role for Gas scenario assumes the small share of buildings using gas (natural gas) today continue to use gas in the future (biomethane). The Limited Role for Gas scenario assumes these buildings adopt electric heat pumps.

For most of this report, we use the Major Role for Gas scenario as our central scenario, and the basis for exploring detailed results. The Major Role for Gas scenario represents a reasonable and realistic vision of how the different demand sectors will decarbonise and the role played by hydrogen and biomethane in the decarbonisation of those sectors.

We then compare key results of the Major Role for Gas scenario with results of the Limited Role for Gas scenario, as well as results for five alternative sensitivity scenarios. The Limited Role for Gas scenario presents another realistic vision of the decarbonisation of the different sectors; however, with a more limited role of hydrogen and biomethane. The five sensitivity scenarios represent variations of the Major Role for Gas scenario with different cost inputs, supply constraints and demand assumptions.

Each demand scenario forecasts energy demand across four energy carriers: electricity, hydrogen, methane – reflecting both demand for natural gas (CH_4) and biogas and/or biomethane ($bioCH_4$) – and heating. These forecasts of energy demand extend from 2020 to 2045 for each Swedish region, creating snapshots of energy demand every 5-years: 2020, 2025, 2030, 2035, 2040 and 2045.

Figure 3 – Main demand scenarios and sensitivity scenarios

Major Role for Gas	Limited Role for Gas
Low-carbon and renewable gas plays a prominent role in all demand sectors. In some sectors, such as road transport, electrification plays the dominant role.	The use of low-carbon and renewable gas is not widespread and is limited to sectors where no reasonable alternative exists

Sensitivities	
Low H_2 Import Costs	Impact due to low hydrogen import costs
Low H_2 Infra. Costs	Impact due to low hydrogen infrastructure costs
Low Electrolyser Costs	Impact due to lower electrolyser costs
Extended Nuclear Lifetime	Impact due to the extended operation of the nuclear fleet
High Electricity & H_2 Demand	Impact due to higher electricity and hydrogen demand

3.1.2 Determining interconnection infrastructure needs

As previously described, our modelling approach determines whether existing electricity or methane interconnections need to be expanded, and whether new interconnections are needed (as in the case for methane and hydrogen). The capacity of expanded and new interconnections is determined based on the minimum capacity required to meet future needs, rather than based on long-term network sizing (which generally oversize transmission investments to accommodate future growth). This distinction is critical because our results are not intended to denote the real capacity of future interconnection infrastructure, rather, they are intended to be represent the minimum need.

For example, our analysis may show that a 1 GW interconnection is required from region A to region B over a 1,000km distance. In this case, a 20-inch pipeline (1.2 GW) would be technically sufficient to accommodate the 1 GW needs of this interconnection. However, it is unlikely that a gas TSO would ever build a 20-inch pipeline over 1,000km because the hydrogen volumes transported would simply not justify the cost of the investment.

In reality, a TSO would either choose to not build the interconnection at all, or to perhaps build a 36-inch pipeline (4.7 GW) that could accommodate future longer-term growth. Our analysis does not perform this right-sizing exercise and simply reports interconnection capacities based on need.

3.1.2 Modelling configuration

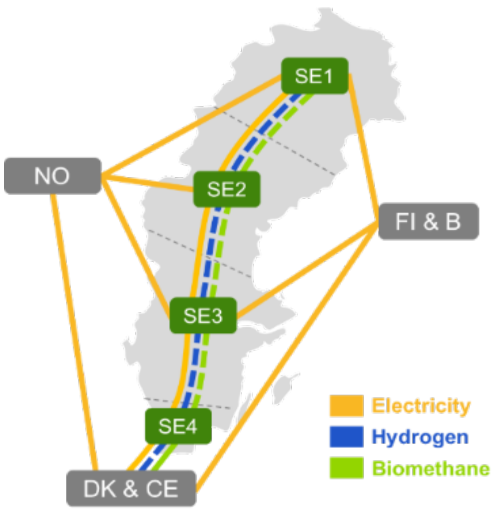
A description of the main configuration parameters of the LCP model and several other modelling considerations is presented below.

Figure 4 – LCP model configuration and key modelling considerations

Geographic Scope

This study divides Sweden into 4 regions corresponding to the 4 existing bidding zones of the Swedish electricity market (SE1, SE2, SE3 and SE4). We also consider 3 neighboring regions: Denmark and Central Europe (DK&CE), Finland & the Baltics (FI&B), and Norway (NO).

All 7 regions are modelled as individual "copper-plate" nodes: each with its unique energy supply and demand conditions, varying over time.



Regional Interconnections

Regions are modelled as an interconnected network of nodes with energy infrastructure connecting a node with its neighboring nodes.

- **Electricity** transport between each region is optimised model-endogenously. Electricity demand and supply capacities in each of the 3 neighboring regions is scenario-defined and largely based on the National Trends scenario of the TYNDP 2020 from ENTSO-E/G.
- **Methane** and **hydrogen** can be imported from DK&CE and is optimised model-endogenously. Solid lines on the map indicate existing transmission infrastructure between regions. Dotted lines indicate no transmission capacity currently exists and investments would be required to enable transport of energy across regions.
- **Heating** is supplied and consumed by each node. No transfer of heat from region to region is allowed.

Energy Carriers

Our demand scenarios forecast energy demand across 4 energy carriers; **electricity**, **hydrogen, methane** – intended to reflect both demand for natural gas (CH4) and biogas (bio-CH4) – and **heating**. Our demand scenarios only reflect energy demand at the end-user level. This excludes energy demand that is transformed into any of these four energy carriers before it is consumed by end-users. For example:

- **Heating** - Energy demand used to generate heat is not defined in our scenarios. This energy mix is determined endogenously by our LCP model (based on an optimisation of costs) and may include electricity (via heat pumps or electric boilers), methane (via gas boilers or CHP) or biomass (via biomass boilers or CHP).
- **Hydrogen** - Electricity and gas demand used to produce hydrogen (via electrolysis or SMR) is modelled endogenously.

Analysis Timeframe	Temporal Resolution
Our demand scenarios extend from 2020 to 2045, creating snapshots of the Swedish energy system every 5-years: 2020, 2025, 2030, 2035, 2040 and 2045. 2020 is used as the base year of the analysis and is calibrated to match the current situation of the Swedish energy system. 2045 is used as the final year of the analysis as it is the target year for Sweden to achieve net-zero, as per Sweden's Climate Act.	Employing four (4) representative seasonal days – winter, spring, summer, and fall – and one (1) peak day – winter peak – to reflect the variability of demand loads and supply resources in Sweden and in neighboring jurisdictions.

Emissions & Sectoral Scope
The focus of our analysis is on achieving the 2045 net-zero target as defined by the Swedish Climate Act of 2018. Since the scope of our analysis is on the energy system –more specifically energy demand from buildings, industry, transport and the power sector – some sectors are excluded from our study. Our analysis does not capture emissions from agriculture, land-use (LULUCF), waste, or embedded emissions from products or materials (e.g. emissions associated with cement used in the construction of buildings). This means that our analysis captures approximately 80% of emissions in Sweden. Emissions associated with international transport are not technically within the scope of Sweden's Climate Act. However, given the importance of the transport sector in an energy system context and how closely linked international and domestic transport can be, particularly in relation to shipping and aviation, we expand the scope of the transport sector to also capture international shipping and aviation. International transport adds an equivalent of 20% of national emissions.

Discount Rate
Capital costs are converted to a levelised amount using an annuity factor based on the economic lifetime of each type of investment and a real discount rate of 5%. This 5% is intended to capture an average cost of capital across private and public perspectives and is not intended to be interpreted as a "societal" discount rate[11].

3.2 Study approach

The approach Guidehouse and Energiforsk followed for this study was divided into three phases.

Phase 1 Focused on data collection and the development of input assumptions. This included the collection of techno-economic parameters for all supply capacity technologies (e.g., onshore/offshore wind power, electrolysers, etc.) and transmission infrastructure (e.g., electricity transmission lines, hydrogen pipelines, etc.). This phase also focused on the collection of Swedish energy system data to accurately characterise the current state of the electricity and gas system (e.g., existing electricity supply capacity in each region, existing transmission interconnection capacity across Swedish and neighboring regions, etc.).

Phase 2 Focused on the development of two main demand scenarios. This included the development of forecasts of electricity, hydrogen, methane and heat demand for each Swedish region from 2020 to 2045. To complement our view on the decarbonisation of industry, transport and building heat, we interviewed several Swedish stakeholders representing both energy supply perspective as well as stakeholders representing energy supply and demand perspectives.

Phase 3 Focused on the configuration and application of the LCP model to optimise the buildout of electricity, hydrogen and methane supply capacity, and related transmission infrastructure from 2020 through 2045. The LCP model was applied to each demand scenario and sensitivity scenarios.

Through this study, a Steering Committee made up of Sweden's gas transmission and distribution network companies was engaged. The Steering Committee provided regular input and feedback on our modelling approach and results. Energiforsk and Guidehouse co-chaired the Steering Committee and worked collaboratively in the development of this report.

[11] Energy infrastructure investments to achieve a net-zero energy system will be financed partly by government and private investors (including electricity and gas TSOs and DSOs). The 5% discount rate is intended to reflect this mix. It considers standard government borrowing rates (0-3%) and higher expected returns for the private sector. This 5% social discount rate is consistent other relevant energy system decarbonisation analyses performed by Guidehouse including Gas for Climate (2019, 2020) and the European Hydrogen Backbone (2020). Further, this is also in line with the discount rate recommended by the European Commission for cost-benefit analysis according to Annex III to the Implementing Regulation on application form and CBA methodology (recommending a 5% discount rate for Cohesion countries and a 3% discount rate for other Member States).

Figure 5 – Overview of study methodology

1. Data Collection & Input Assumptions	2. Development of Demand Scenarios	3. Supply & Infrastructure Optimisation (LCP Model)
Techno-economic parameters – Development and collection of techno-economic parameters of existing and future investment technologies (e.g., offshore wind, H_2 storage, electrolysers, etc.). These inputs were sourced from TYNDP, IEA, ENTSO-E/G, IRENA, NREL, among others. **Technology Scope** – Includes all electricity generation and gas production technologies, conversion technologies, storage and transmission infrastructure.	**Scenarios** – Development of 2020-2045 forecast for electricity, district heating, hydrogen, and methane demand **Geographies & Sectors** – Demand forecasts for each Swedish region (SE01-SE04) and three demand sectors: building heating, transport and industry.	**Gas Supply & Gas Infrastructure** – Configuration of the LCP model to the Swedish energy system and neighboring regions to optimise the buildout of supply capacity and transmission infrastructure. **Alternative Scenarios & Sensitivities** – Exploring the impact of alternative demand scenarios and sensitivities on the role of gas supply and infrastructure

Steering Committee

A **Steering Committee** group made up of Nordion Energi, Kraftringen, Gasnätet Stockholm, Öresundkraft, and Göteborg Energi, alongside Energiforsk, provided input and feedback throughout the study process.

Stakeholder Consultation Process

Two stakeholdering consultation processes were conduced. The first consultation process, conducted in parallel to **Phase 1**, gathered input from large end-users and industry groups – across steel, mining, heavy-road transport and shipping – to support the development of the demand scenarios. The second consultation process, conduced after **Phase 3,** gathered feedback from major energy stakeholders – electricity and gas companies, public agencies, large end-user groups, industry associations and the government – to identify the major barriers and challenges on the way of scaling up electricity and gas supply and infrastructure

Chapter 4
Energy Demand Scenarios

To assess the role of gas supply and gas infrastructure in the Swedish energy system, we developed two main scenarios of energy demand. These scenarios represent two different but plausible futures of energy demand in Sweden. Neither scenario is intended to represent the best or most likely decarbonisation pathway. Rather, the objective of this study is to explore the role gas supply and gas infrastructure play in enabling the decarbonisation of the Swedish energy system, whether in a future with significant gas demand or another with more limited demand.

In this section, we describe the development of two demand scenarios, **Major Role for Gas** and **Limited Role for Gas**. As described earlier, for most of this report we use the Major Role for Gas scenario as our central scenario to explore detailed modelling results. Results for the second scenario, Limited Role for Gas, and various other sensitivity scenarios, are also presented in subsequent sections and compared with results of the Major Role for Gas scenario.

- **Section 4.2** describes the development of the two demand scenarios; Major Role for Gas and Limited Role for Gas; and
- **Section 4.3** presents the energy demand forecasts developed based on the Major Role for Gas scenario, for each of the 4 Swedish regions.

4.1 Major Role for Gas and Limited Role for Gas

Our two demand scenarios present alternative views on how three demand sectors – buildings, transport, and industry – will decarbonise by transitioning away from fossil fuels to low-carbon and renewable energy sources. In this context, our two scenarios provide two hypothesis of how central hydrogen and biomethane will be in the decarbonisation of the energy system.

- The first scenario, Major Role for Gas, is a scenario in which renewable and low-carbon gas play a prominent role across all three demand sectors.
- In the second scenario, Limited Role for Gas, gas plays a more limited role in all demand sectors.

Figure 6 – Description of energy demand by sector

BUILDINGS	**Building heating** includes heating demand from residential and commercial buildings	Heat demand from buildings can be decarbonised through several low carbon heating alternatives such as electric heat pumps, district heating and biomass. In the future, newer and renovated buildings will have better insulation which will reduce heating demand, as well as more efficient heating equipment.
TRANSPORT	**Transport** includes energy demand from light and heavy road transport, shipping, and aviation	Today, energy demand in the transport sector is heavily reliant on fossil fuels. The transport sector will decarbonise largely in line with global trends given that fueling / charging infrastructure will need to be largely consistent across borders to enable international transport. Electrification, hydrogen, biomethane, and biofuels will all contribute to the decarbonisation of transport.
INDUSTRY	**Industry** includes energy demand from all major energy-intensive industries	The decarbonisation of industrial process requiring low and medium temperature (e.g. below 150°C) will most likely rely on electrification. High temperature heat will be more challenging, which may require research and development into new low-carbon technologies.

These two scenarios are neither completely different, nor completely similar. This is by-design because our objective is, first, to adopt two realistic scenarios that will yield two different decarbonisation pathways and, second, to assess the implications of those different pathways on the development of gas supply and infrastructure. Both scenarios therefore do share the same decarbonisation pathways in some demand sectors, and in other sectors some degree of similarity. These similarities reflect the confidence and certainty shared by many industries and energy stakeholders on how some sectors are expected to decarbonise. For example:

- In the **iron ore and steel industry**, the views of all major steel stakeholders in Sweden – including LKAB, HYBRIT and H_2 Green Steel – have consolidated behind the adoption of hydrogen-based direct reduction of iron ore (HDRI) as the only plausible decarbonisation strategy in time for 2045[12]. Hence, the roll-out of the HDRI technology is incorporated in both scenarios.
- Similarly, in the **aviation sector**, the decarbonisation of fossil fuel use is expected to be driven by global aviation trends, rather than by unique market drivers in Sweden. Because of this dependence on global trends, the decarbonisation of the aviation sector is the same in both scenarios.
- In the **light-duty road transport sector**, the adoption of electric vehicles (EVs) is expected to be the most common way of decarbonising transportation by passenger vehicles. As a result, both scenarios are based on a large adoption of EVs; 100% EV penetration in one scenario and 95% penetration in the other scenario – with the remaining 5% from hydrogen fuel cells.

The following sub-sections describe how each of the three demand sectors are projected to decarbonise in each scenario and their respective 2020-2045 forecasts of energy demand. The major differences of how individual demand sectors will decarbonise are summarised here:

- In **building heat**, the Major Role for Gas scenario assumes the small share of buildings using gas (natural gas) today continue to use gas in the future (biomethane). The Limited Role for Gas scenario assumes these buildings adopt electric heat pumps.

[12] Today, approximately two-thirds of steel production uses blast furnaces (BF) which in turn use coking coal. Blast furnaces will be decarbonised with the use of hydrogen gas as the reduction agent. Hydrogen-based direct reduction of iron ore (HDRI) is currently the most viable alternative to BF-based steel production process. LKAB, HYBRIT and H_2 Green Steel all have plans to adopt the HDRI process in the future. The output of HDRI process will be iron sponge and/or hot briquette iron (HBI), which can then be processed in electric arc furnaces.

- In **transport**, the Major Role for Gas scenario assumes biomethane and hydrogen play a major role in heavy road transport (trucks and buses) and shipping. The Limited Role for Gas assumes the role of biomethane and hydrogen is much more limited. The Major Role for Gas scenario also assumes a small share (5%) of light road transport uses hydrogen, while the Limited Role for Gas scenario assumes light road transport is fully electrified.
- In **industry**, while hydrogen features heavily in both scenario with the adoption of the HDRI process in the production of steel, biomethane plays a very small role in the Limited Role for Gas scenario.

4.1.1 Decarboisation of building heating

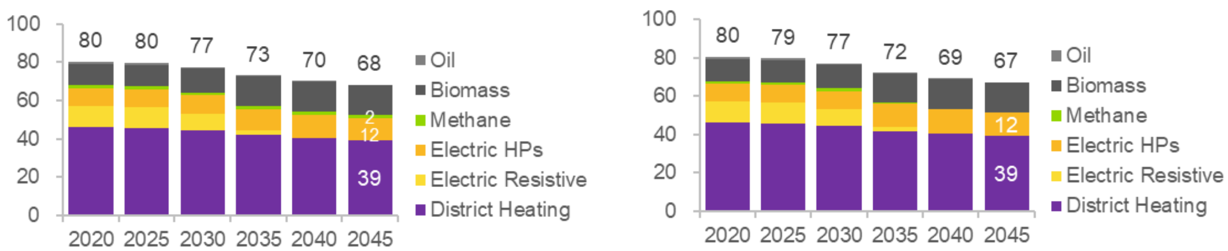
Building heating has already been largely decarbonised in Sweden. Only c.3% of the total heating energy mix continues to rely on fossil fuels like natural gas and oil. Since heating is already largely based on renewable or low-carbon energy sources, the evolution of the heating sector in both scenarios is quite limited. In both scenarios, district heating remains the dominant source of heat in 2045[13], while electric heat pumps and biomass play complementary roles. The major difference between both scenarios is related to the small share of buildings using natural gas.

- In the **Major Gas scenario**, these buildings continue to rely on the gas network for heating, however, over time the network gradually transitions to biomethane
- In contrast, in the **Limited Gas scenario**, heating in these buildings is displaced by electric heat pumps.

In both scenario, energy demand for building heating declines slightly. This decline is driven by improvements in energy efficiency of new building stock and the renovation of existing building stock. Energy demand is slightly lower in the Limited Gas scenario because of the higher efficiency of electric heat pumps – which displace gas heating in the Major Gas scenario. In both scenarios, district heating remains the largest source of heating, accounting for over 55% of total energy demand energy.

Figure 7 – Building heat energy demand, by demand scenario

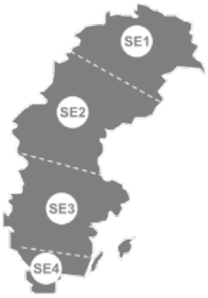
Major Role for Gas	Limited Role for Gas
• **Energy demand decreases steadily** from 80 TWh down to 68 TW by 2045. • **Gas demand for heating remains at currently levels** (~2 TWh) through 2045.	• **Energy demand decreases steadily** from 80 TWh down to 67 TW by 2045. • **Gas demand decreases down to zero by 2045**, replaced by high-efficiency electric heat pumps.



Note: *These energy forecasts represent final energy demand by end-users, rather than primary energy demand. This means, these forecasts don't reflect electricity, gas or biomass used in district heating plants, rather only heat demand from district heating by end-users.*

[13] The energy mix used in district heating – e.g., the mix of gas boilers, electric heat pumps, CHP, biomass, etc. – is endogenously defined by the model. Energy supply from these DH sources is additional to the energy mix of gas, electricity and biomass described above, as defined in each demand scenario.

Regional Insights



- **Gas heating** is limited to the southwest coast of Sweden (SE3 and SE4) where the gas network is available today, across Skåne, Halland and Västra Götaland.
- **District heating** is the predominant form of heating across most of the country, from south to north, however the prevalence varies across the type of building. District heating penetration is more than 90% in multi-family homes, approximately 70% in commercial buildings and less than 25% in single-family homes.
- **Electric heating**, whether resistive heating (e.g., electric baseboard) or heat pumps are more predominant in single-family homes.
- In general, energy demand for building heat is distributed across Sweden in line with the distribution of population, with the vast majority of the population located in the south – ~60% in SE3 and ~30% in SE4.

4.1.2 Decarbonisation of transport

The transport sector is composed of three different sub-sectors: road transport, shipping, and aviation. Decarbonisation trends across of each of these sub-sectors are drastically different. Nevertheless, since transport networks are regionally and globally interconnected, the types of vehicles adopted in Sweden and the associated fueling infrastructure will resemble global trends.

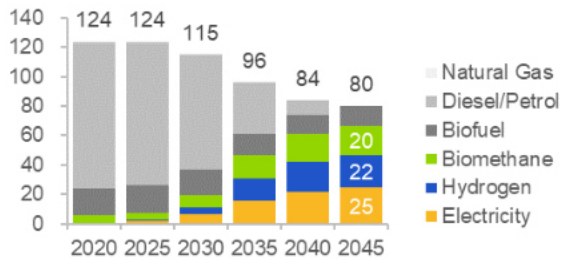
Both scenarios are characterised by common trends in light duty road transport and aviation. In light duty transport, EVs are by and large the preferred vehicle option, while in aviation –influenced by global trends – synthetic kerosene (“e-kerosene”) and advanced biodiesel displace jet fuel.

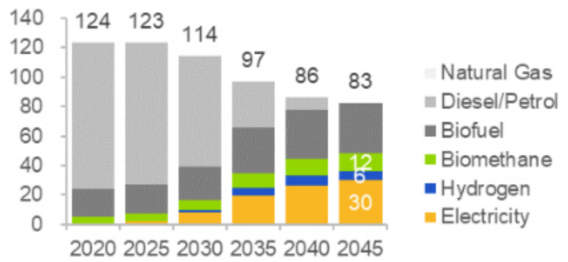
- In the **Major Gas scenario**, while EVs dominate light duty transport, hydrogen fuel-cell EVs (FCEVs) also play a role in niche delivery use cases. In heavy duty transport, hydrogen and liquified biogas (LBG) play an increasing role, complemented by electrification. In shipping, gas plays a dominant role through LBG and hydrogen-derived fuels like ammonia and methanol.
- In the **Limited Gas scenario**, light duty transport is fully electrified, with gas demand being limited to heavy, long-distance road transport. In shipping, unlike in the Major Gas scenario, biodiesel and electricity also play roles – with electricity being primarily used for coastal shipping and short-distance, commuter shipping. Gas alternatives, like LBG, ammonia and methanol, are predominantly limited to long-distance shipping.

In both scenarios, energy demand declines steadily through 2045. This decline is driven by increasing efficiencies across all transport methods but is partially offset the increasing demand for road transport, shipping and aviation. The decline in demand is largely a result of the level of electrification in light- and heavy-duty road transport as the fuel efficiency of EVs is significantly higher than traditional fuels like diesel or petrol. While total energy demand decreases in both scenarios, demand for electricity, hydrogen and biomethane increases.

Figure 8 – Transport energy demand, by demand scenario

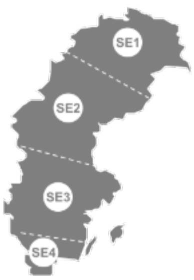
Major Role for Gas	Limited Role for Gas
• **Energy demand decreases from 124 TWh down to 80 TWh**; however, gas volumes increase significantly, almost evenly across hydrogen and biomethane. • **Hydrogen increases to 22 TWh while biomethane demand increases to 20 TWh**.	• **Energy demand decreases from 124 TWh down to 83 TWh**. Compared to the Major Gas scenario, gas volumes only increase moderately. • **Hydrogen increases to 6 TWh while biomethane demand increases to 12 TWh**





Note: These energy forecasts represent final energy demand by end-users, rather than primary energy demand. This means, these forecasts don't reflect electricity use in hydrogen production, rather only hydrogen demand by end-users.

Regional Insights



- **Road Transport** | Energy demand for light- and heavy-road transport is distributed across Sweden in line with the distribution of population. Most energy demand for road transport is in SE3 and SE4 – where major cities like Stockholm, Göteborg, Uppsala and Malmö is located.
- **Aviation** | The location and distribution of energy demand for aviation is highly regional and dependent on where major international and domestic airports are located. Nearly 90% of energy demand for aviation is in SE3 – where Stockholm's Arlanda, Bromma and Skavsta airports are located, along with the Göteborg-Landvetter airport.
- **Shipping** | Similar to aviation, the location and distribution of energy demand for shipping is highly regional, dependent on where major shipping ports are located. Nearly 85% of energy demand for shipping is in SE3, where the ports of Stockholm, Göteborg and Donsö are located.

4.1.3 Decarbonisation of industry

Energy demand in industry varies largely from sector to sector influenced by the types of industrial processes required and the need for medium and high-heat temperate for industrial applications. To develop the demand scenario, our analysis divided industry into six sub-sectors: steel and metals, metal-mining, non-metal mining, pulp & paper and wood products, chemicals and other industries. Energy demand in industry is already largely decarbonised, with most energy needs already met by biomass and electricity. Only about 20% of energy needs are met with fossil fuels, equivalent to c.30 TWh. Of this, roughly half is associated with the steel and metals sector, where coal-fired blast furnaces are used.

Major sub-sectors have already defined decarbonisation roadmaps. For example, the Swedish Steel Association (Jernkontoret), LKAB and SSAB have developed a clear pathway and timeline for how the steel and metal sectors will decarbonise. Similarly, the Swedish Mining Association (SveMin) has also published its view on how the mining sector will transition away from fossil fuels.

Since there is already some level of certainty on how the major fossil-fuel consuming sectors will decarbonise, the decarbonisation of industry across both the Major Gas and Limited Gas is relatively similar.

- **Steel |** Both scenarios assume coal-fired blast furnaces are replaced by the HDRI process. The conversion timeline of SSAB's blast furnaces to electric arc furnaces is expected to occur between 2025 and 2030 at Oxelosund in SE3, followed by the blast furnaces at Lulea in SE1 as early 2035-2040. While the SSAB timeline is only relevant for the HYBRIT venture (which represents approximately 20 to 25% of the energy requirements of the full adoption of HDRI by LKAB), its timeline has been used as the basis for the full HDRI conversion timeline. As announced by LKAB, the full conversion – not just the HYBRIT portion of their operations – will increase their electricity demand to 55 TWh. Approximately 48 TWh of these 55 TWh is associated with electricity demand for green hydrogen production.
- **Mining (Metal and Non-Metal) |** The decarbonisation of the metal-mining sector is also largely defined given how tightly linked the sector is to steel production. In non-metal mining, the use of petroleum oil in furnace and kilns is displaced by biomass, while low/medium-temperature industrial processes are electrified. Both sub-sectors also include the electrification of transport equipment and the use of electric heat pumps for low-temperature heating processes.

The major difference across scenarios relate to the role played by biomethane and electricity in decarbonising low- and medium-heat temperature in all other industry sectors – pulp, paper & wood products, chemicals, and other industries. In the **Major Gas** scenario, biomethane plays a more prominent role, while in the **Limited Gas** scenarios, electrification is preferred.

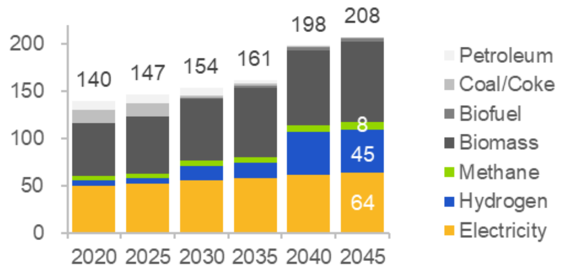
Unlike the declining energy demand trends in transport and buildings, energy demand in industry increases significantly from 2020 to 2045. This is driven by two factors: demand for hydrogen in the decarbonisation of the steel sector via HDRI, and an increasing production forecasts in the pulp, paper & wood products sector. However, as most energy demand in pulp, paper & wood products is met via biomass, this only leads to a small increase in gas demand.

The 2020-2045 forecasts of energy demand represent energy consumed by end-users, rather than the primary source of energy. This means, these forecasts do not reflect electricity needed for the production of hydrogen, but rather only reflect hydrogen demand by end-users.

Figure 9 – Decarbonisation of industry by demand scenario

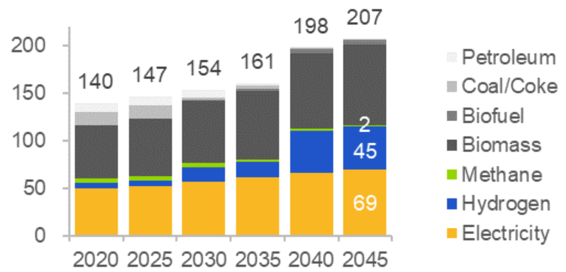
Major Role for Gas

- **Energy demand increases from 140 TWh to 208 TWh**
- **Hydrogen demand increases** significantly to 45 TWh, while **biomethane volumes remain at similar levels** as today at 8 TWh



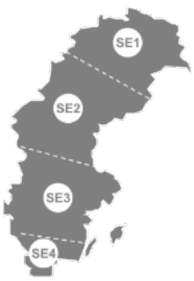
Limited Role for Gas

- **Energy demand increases from 140 TWh to 207 TWh**
- As in the Major Gas scenario, **hydrogen demand increases** to 45 TWh, however, as electrification takes a more prominent role, **biomethane declines** to 2 TWh.



Note: *These energy forecasts represent final energy demand by end-users, rather than primary energy demand. This means, these forecasts don't reflect electricity use in hydrogen production, rather only hydrogen demand by end-users.*

Regional Insights



- **Steel |** With the adoption of the HDRI process, hydrogen demand will be concentrated in SE1, where LKAB's operations are located. Demand for hydrogen will in turn increase demand for electricity. In addition to electricity demand for hydrogen production, some additional electricity growth will also be driven by the transition to electric arc furnaces in SE1, where SSAB's Lulea blast furnaces are located, and in SE3 where the Oxelosund blast furnaces are located. Electric arc furnaces are already in operation in SE3 (Vastmanland) and SE4 (Hoganas).
- **Mining |** Most major iron-ore, base metal and gold mines are in the north of Sweden in Norrbotten in SE1. Base metal mines (lead, silver, zink) are also found near Örebro in SE3.
- **Chemicals |** Most chemical and refining operations are located in SE3 along the west coast near Göteborg and Helsingborg. This is also where the vast majority of existing hydrogen demand is.
- **Pulp, Paper & Wood Products |** Most facilities are found in SE3 and SE2 along the east coast in Gävleborg and Västernorrland, as well as inland in SE3 in Västra Götaland and Östergötland.

Figure 10 – Description of demand scenarios for each demand sector

	Major Role for Gas	Limited Role for Gas
	Low-carbon and renewable gas plays a prominent role in all demand sectors. In some sectors, such as road transport, electrification plays the dominant role.	**The use of low-carbon and renewable gas is not widespread and is limited to sectors where no reasonable alternative exists**
BUILDINGS	**The building heating energy mix remains largely unchanged, including the small share of buildings relying on gas for heating.** • **District heating** remains the dominant source of heat. • **Gas** demand, although quite limited today, remains at similar levels. • **Electric** heating increases slightly over time with electric heat pumps displacing all other electric resistive heating pump • **Biomass** increases slightly over time	**The building heating energy mix remains largely unchanged, however, the small share of buildings relying on gas adopt heat pumps.** • **District heating** remains the dominant source of heat. • **Gas** heating, which is already quite limited, declines to zero • **Electric** heating increases slightly over time with electric heat pumps displacing all other electric resistive heating pump • **Biomass** increases slightly over time
TRANSPORT	**Gas plays a significant role in all types of heavy transport; road, shipping, and aviation, but a very limited role in light duty transport.** • **Light duty transport** is almost completely electrified, with hydrogen (in fuel-cell vehicles) playing plays a minor role. • In **heavy duty transport**, hydrogen and bio-CNG/LNG play a major role, complemented by electrification. • In **shipping**, bio-LNG and hydrogen-derived ammonia and methanol play dominant roles. Electricity is limited to short-distance, coastal shipping. • In aviation, hydrogen (used in the **production** of synthetic kerosene) plays a major role, complemented by bio jet fuel.	**Gas plays a less prevalent role, with gas demand limited to heavy road transport and shipping. Electrification plays a more dominant role.** • **Light duty transport** is completely electrified. Gas does not play any role. • **Heavy duty transport** is also mostly electrified. Gas demand is limited to bio-CNG/LNG use in trucks. • In **shipping**, electricity, biofuel, and bio-LNG all play major roles. Hydrogen-derived fuels do not play a role in shipping. • In **aviation**, hydrogen (used in the production of synthetic kerosene) plays a major role, complemented by bio jet fuel.
INDUSTRY	**Gas volumes increase significantly, largely driven by the Steel and Chemicals sectors, but also across other industries.** • There aren't any major differences across scenarios since most **gas** demand is associated with hydrogen use in Steel production and as feedstock in the Chemicals sector. • In both scenarios, **biomass** demand increases due to growth in the Pulp, Paper & Wood Products sector. • **Biomethane** plays a more prominent role leading to higher demand than in the Limited Gas scenario	**Gas volumes increase significantly, almost exclusively driven by in the Steel and Chemicals sectors.** • There aren't any major differences across scenarios since most **gas** demand is associated with hydrogen use in Steel production and as feedstock in the Chemicals sector. • In both scenarios, **biomass** demand increases due to growth in the Pulp, Paper & Wood Products sector. • **Electricity** plays a more prominent role leading to higher demand than in the Major Gas scenario

4.2 Comparison of demand scenarios

In the previous section, we presented forecasts of final end-user energy demand, for each of the three demand sectors. In this section, the focus shifts from final energy demand – in other words, “direct” energy demand – to total energy demand – to reflect both “direct” and “indirect” energy demand. In this case, “indirect” energy demand refers to demand of a particular energy carrier needed in the production of another energy carrier. For example, this includes electricity used in the production of hydrogen (via electrolysis), methane used in the production of hydrogen (via SMR), or methane used in the production of heat (via district heating), among others.

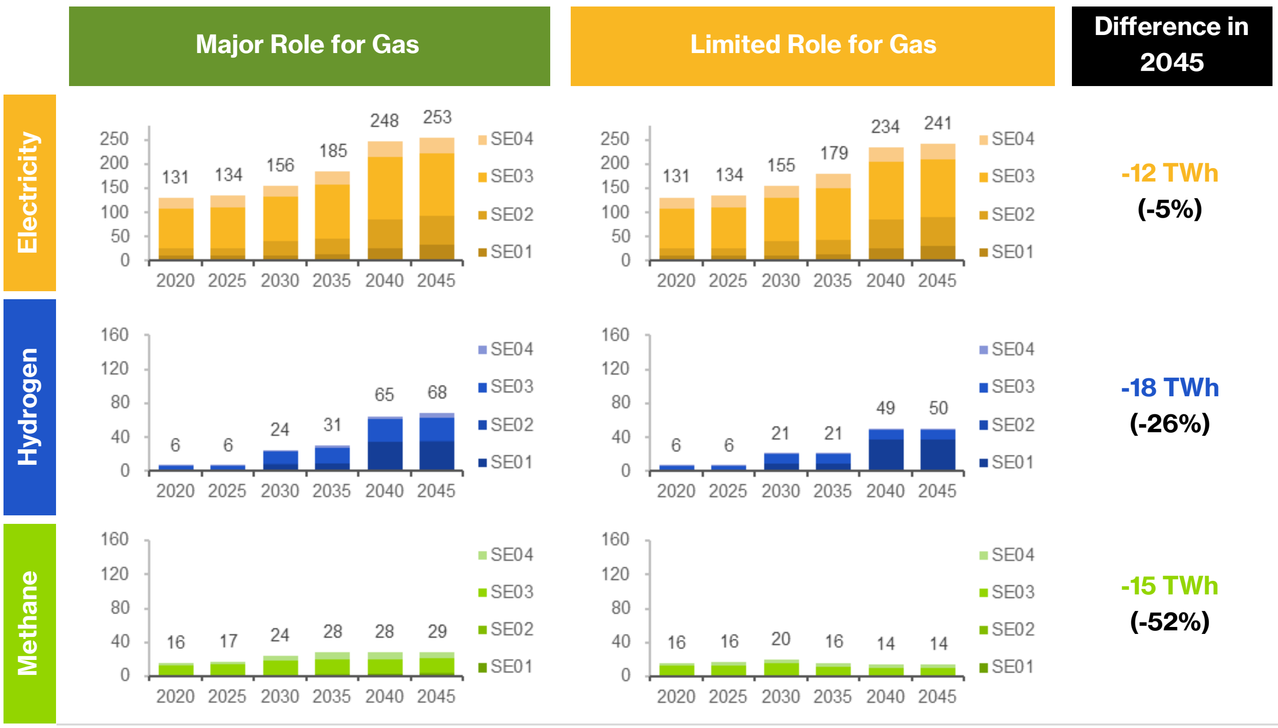
The forecasts of electricity, hydrogen and methane demand presented below represent direct and indirect energy demand, aggregated across all three demand sectors and across all four Swedish regions.

Electricity Electricity demand increases significantly in both scenarios. In the Major Role for Gas scenario, electricity increases from 131 TWh to day to 253 TWh by 2045, while in the Limited Role for Gas scenario, demand increases to 241 TWh.

Hydrogen In the Major Role for Gas scenario, hydrogen demand increases from 6 TWh today to 68 TWh, while in the Limited Role for Gas scenario, demand increases to 50 TWh.

Methane In the Major Role for Gas scenario, methane demand increases from 16 TWh today to 29 TWh, while in the Limited Role for Gas scenario, demand remains around current levels, first rising slightly to 20TWh by 2030 and then decreasing down to 14 TWh.

Figure 11 – Comparison of demand scenario forecasts



4.3 Regional demand forecasts for the Major Role for Gas scenario

Since the Major Role for Gas scenario is used as our central scenario for most of this report, this section presents the resulting regional forecasts of electricity, hydrogen and methane demand, from 2020 to 2045, for each of the Swedish regions. This forecast incorporates energy demand driven by cross-sectoral demands. For example, electricity demand for hydrogen production is incorporated into the electricity demand forecast.

Electricity Demand nearly doubles from 131 to 253 TWh. Some of this growth occurs in SE3 where most major cities are – increasing from 84 to 128 TWh. However, the biggest increase occurs in SE2, where electricity is needed to produce hydrogen – increasing from 14 to 60 TWh. While SE2 has limited hydrogen demand, it plays a key role in the production and delivery of hydrogen to other regions. This is explored further in subsequent sections.

Hydrogen Hydrogen demand increases from 6 to 68 TWh. More than half of this demand occurs in SE1, where a steel and mining cluster develops. Growth in hydrogen demand in SE3 is also significant, where smaller industry and transport clusters develop.

Methane Demand nearly doubles from 16 to 29 TWh. This increase is largely driven by methane demand from heavy road transport (primarily freight transport) and shipping. Growth in demand is primarily in SE3 and SE4, where major transport hubs and ports are located.

Figure 12 – Energy demand forecasts by region, Major Role for Gas


HYDROGEN
ENERGY STORAGE

Chapter 5 Supply Capacity Pathways

Section 5 and Section 6 present the pathway results of our optimisation modelling using the Major Role for Gas scenario as the central scenario. The Major Role for Gas scenario represents a reasonable and realistic vision of how the different demand sectors will decarbonise and the role played by hydrogen and biomethane in the decarbonisation of those sectors. Results for the Major Role for Gas scenario are used as the basis to explore the role played by gas supply and gas infrastructure in decarbonising the energy system. In subsequent sections, the role of gas supply and gas infrastructure is explored under alternative demand scenarios and sensitivity scenarios.

This section, **Section 5**, presents the optimised buildout of electricity, hydrogen and methane supply capacity from today to 2045, both at the national level and for each individual Swedish region.

- **Section 5.1** focuses on the expansion of electricity supply, beginning with a view of trends at the national level, then exploring trends across each region.
- **Section 5.2** focuses on the expansion of hydrogen supply capacity, once again beginning with national trends, and then exploring regional trends; and
- **Section 5.3** focuses on the expansion of methane supply capacity, also at the national and regional level.

5.1 Electricity supply capacity

Electricity supply capacity is forecast to increase significantly from 40 GW today to 86 GW by 2045. This increase in capacity is driven growth in electricity demand, which is forecast to nearly double from 130 TWh today to 253 TWh by 2045. Most of the growth in supply capacity occurs post-2030, in line with the timeline of demand growth due to electrification and electricity demand for hydrogen production.

Large growth in onshore and offshore wind

Most of the increase in capacity is associated with onshore and offshore wind. Combined, wind capacity increases from 9 GW today to 53 GW, corresponding to approximately 25 TWh of electricity production today, increasing to 180 TWh by 2045. Today, virtually all wind capacity is located onshore, most of which is in the center and north of Sweden in SE3 and SE2. Historically, SE3 and SE2 have been Sweden's powerhouses of onshore wind development. By 2045, wind capacity is much more evenly distributed from south to north, with roughly 70% of offshore wind capacity being installed in the south of the country (in SE3 and SE4), where offshore wind conditions are highly attractive.

Nuclear fleet decommissioning by 2045

The large growth in wind capacity is also driven by the large gap in electricity supply left by the decommissioning of Sweden's nuclear fleet. Our analysis assumes decommissioning take place over 2040 and 2045. Today's nuclear fleet of approximately 7 GW, composed of reactors at Forsmark, Oskarshamn and Ringhals (all located in SE3), generates roughly 46 TWh of electricity. The nuclear fleet is assumed to stay fully operational until 2035. In 2040, the oldest Forsmark reactor is assumed to be decommissioned as it reaches the end of its technical life (60 years). By 2045, all remaining reactors at all sites are assumed to also be decommissioned as they reach their end of life[14]. With the decommissioning of the nuclear fleet, hydropower plays a more prominent role as baseload.

Hydro reservoirs and interconnections provide flexibility

Large hydro reservoirs in SE2 and SE1 become increasingly critical in delivering flexibility as more and more wind capacity comes online. While no new hydro capacity is forecast through 2045, transmission interconnections with Norway, Denmark and Finland expand giving the system additional flexibility and capacity to balance wind supply and demand, transferring power across Sweden and with neighboring regions.

Our analysis does not find a major role for hydrogen in energy supply or flexibility.

With the large capacity of hydro reservoir and the highly interconnected Nordic grid[15], our analysis does not see a role for hydrogen (via gas-to-power) in energy supply or in providing flexibility. While this finding is not unexpected given the context of the Nordic electricity system, this outcome may also be driven by the temporal granularity of our modelling methodology. Our analysis uses five (5) representative 24-hour periods to model the hourly dispatch and optimisation of electricity supply; four of these are seasonal representative days – winter, spring, summer, and fall – and the last is a winter peak-day. One of the challenges of this approach is that, with climate change, extreme weather events are becoming more frequent which makes it more difficult to properly characterise representative days.

In comparison to our approach, a more time- and geographically-granular analysis – for example, one considering all 8760 hours of the year with a careful view on local congestion and resource adequacy – would better capture extreme weather events and their impact on the power system. This approach would potentially reach different conclusions regarding the use of hydrogen in the power sector. Nevertheless, based on the high degree of flexibility already present in the Swedish electricity system, we would not expect hydrogen to feature as a major source of electricity supply throughout the year. A more likely finding is that hydrogen may play a role as a flexible peaking resource, operating up to a few hundred hours of the year during extreme power system conditions or when other dispatchable resources are unavailable.

[14] This study does not consider new nuclear reactors as a future supply option in Sweden.

[15] In addition to reflecting the high degree of interconnection that exists with neighboring regions, our analysis also reflects existing hydro reservoirs – and all other electricity supply resources – in these other regions. In this context, the role of Norwegian hydro reservoirs providing flexibility to Norway and neighboring regions (including Sweden) is also reflected.

The integration of electricity and hydrogen supply.

Over time, as the electricity and hydrogen energy systems become increasingly integrated, changes in the flows of power from region to region begin to develop. Traditionally, electricity generated by hydropower in SE1 and SE2 – where approximately 85% of all hydropower capacity is located – flows southbound towards SE3, where most of the country's electricity demand is concentrated. With little electricity demand, no hydrogen demand and increasing shares of onshore wind, SE2 has a growing oversupply supply of power. To the south in SE3, significant electricity and hydrogen demand is expected, and to the north in SE1, significant hydrogen demand. This puts SE2 in an optimal position to not only continuing exporting power to SE3, but to also use its oversupply of electricity to produce hydrogen and supply demand in SE1 and SE3.

Figure 13 – Electricity supply capacity

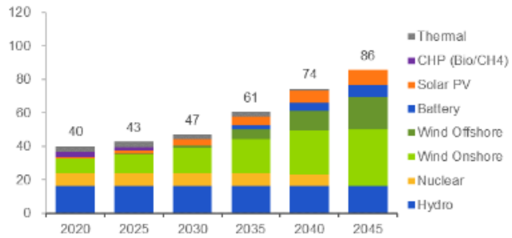
Region	Annual Supply Capacity (GW)	Highlights
		Electricity supply capacity increases 2x from 40 GW today to 86 GW by 2045. Most of the increase in generation capacity occurs after 2030, primarily driven growth in offshore and onshore wind capacity. This buildout is driven by an almost doubling of increasing demand, in turn largely driven by hydrogen demand

Figure 14 – Annual electricity supply

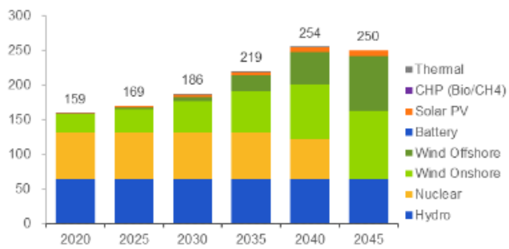
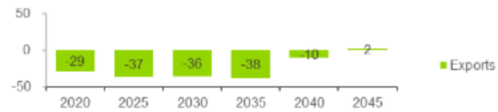
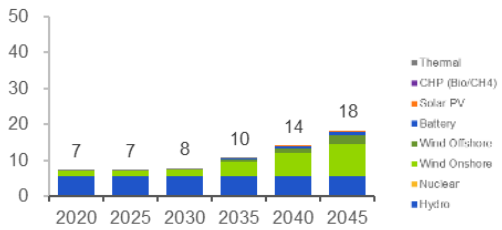
Region	Annual Energy Supply (TWh)	Highlights
	**Annual Domestic Electricity Supply (TWh)**  **Annual Electricity Imports/Exports (TWh)** 	Domestic electricity supply is dominated by hydro and nuclear until 2030. Wind plays an increasing role in the generation mix, becoming the largest source of electricity by 2040. Electricity supply increases rapidly from 2030 to 2040, flattening after 2040 due to the nuclear phaseout. Sweden remains a net-exporter of electricity to other Nordic countries until 2040. In 2045, imports and exports roughly net off to zero.

Figure 15– Electricity supply capacity by region

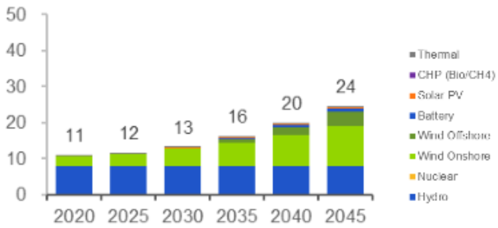
Region	Annual Supply Capacity (GW)	Supply Capacity Buildout



Historically, the electricity supply mix in SE1 has largely been dominated by hydropower, with 6 GW of currently installed capacity.

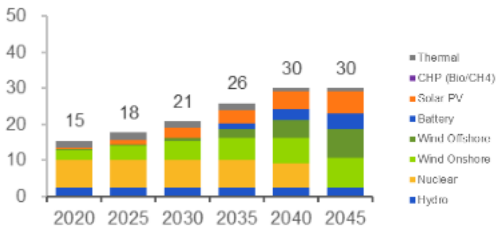
Generation capacity is forecast to increase from 7 GW today to 18 GW by 2045.

Most of this increase occurs post-2030 as onshore wind capacity ramps up, complementing existing hydropower capacity.



SE2 is Sweden's hub of hydropower with 8 GW of installed capacity. SE2 also has the largest share of onshore wind, with approximately 3 GW of installed capacity.

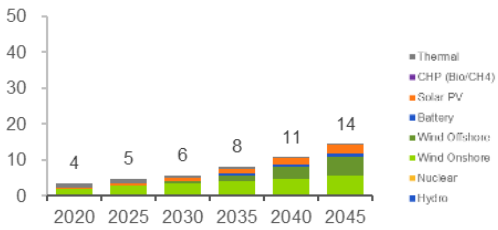
Generation capacity is forecast to increase from 11 GW today to 24 GW by 2045, largely driven by continued growth in onshore wind, some growth in offshore wind.



SE3 has Sweden's largest share of electricity generation capacity with 15 GW.

The nuclear fleet, with reactors at Forsmark, Oskarshamn and Ringhals, accounts for over 50% of this capacity with 7.7 GW.

Despite the decommissioning of the nuclear fleet during the 2040-2045 period, installed capacity in SE3 is forecast to double to 30 GW, largely driven growth in onshore and offshore wind, and solar PV.



SE4 has the smallest electricity generation fleet of all regions.

Generation capacity is forecast to grow 3.5x from 4 GW today to 14 GW by 2045, largely driven by growth in onshore and offshore wind.

5.2 Hydrogen supply capacity

Hydrogen supply capacity is forecast to increase from approximately 550 MW_{H2} today to 9.7 GW_{H2} by 2045 (equivalent to 13 GW_{Elec}). This increase in supply capacity is almost exclusively electrolyser capacity, with only very limited additional SMR capacity. Growth in hydrogen supply capacity is tied to growth in demand, which is forecast to increase from approximately 6 TWh today to 68 TWh by 2045. Growth in hydrogen demand is staggered between 2030 and 2040, driven by the timeline of the steel sector to decarbonise with the adoption of the HDRI process.

New hydrogen supply capacity is largely from electrolysers

Installed electrolyser capacity today is virtually zero. The high costs of electrolysers continue to make the production of green hydrogen cost-prohibitive compared to blue and grey hydrogen. As costs continue to decline, and hydrogen demand continues to grow, green hydrogen is expected to scale rapidly. Electrolyser capacity is expected to grow rapidly starting from 2030, reaching 9.0 GW_{H2} by 2045 (equivalent to 12.6 GW_{Elec}). Most growth in electrolyser capacity is forecasted from 2035 to 2040, when most of the HDRI transition by the steel sector is assumed to materialise.

While not modelled in our analysis, electrolysis byproducts – like oxygen and heat – have the potential to further improve the economics of electrolysers. Roughly 25 to 30% of the energy generated via electrolysis is produced as heat, which can be utilised for building heating or low-temperature heating processes. The oxygen produced can also provide opportunities for synergies with other applications or processes, or can be sold to third parties.

Hydrogen production via SMR will continue playing a role

Today, approximately 550 MW_{H2} of SMR capacity is used to supply roughly 4 TWh of hydrogen demand from the chemicals sector and refineries, both industries largely concentrated along the west coast in SE3. Our analysis shows that, while limited, new SMR capacity will continue to be installed up to 2030. After 2030, new investments will steer predominantly towards green hydrogen via electrolysis, nonetheless, existing already paid-for blue hydrogen installations will continue to be operational[16]. Post-2030, retrofitted SMR capacity with CCS will continue to remain relevant in the production of hydrogen[17]. Hydrogen production via SMR+CCS has the potential to become a source of negative emissions if the methane used in the production process is biomethane rather than natural gas. This is relevant in the context of Nordion Energi developing a 100% renewable methane grid. The carbon storage needs of CCS are also an important consideration. While Sweden has relatively poor potential for underground storage sites for CO_2, Swedish industry players – Preem and Stockholm Exergi – have partnered with the Northern Lights project to evaluate solutions for carbon delivery and transport to North Sea storage sites.

Electrolyser capacity largely installed in SE2.

Between 2025 and 2030, green hydrogen becomes cost competitive. From this point on, all new hydrogen supply capacity is forecast to be electrolysers. Roughly 40% of all new electrolyser capacity is installed in SE2, and while there is no hydrogen demand in SE2, SE2 acts a hydrogen production hub partially serving demand in SE1 in the north, and in SE3 in the south. SE2 is favored with a significant surplus of electricity supply capacity, most of which today flows south to SE3. While SE2 continues to supply electricity demand in SE3, some of its electricity generation capacity is used to produce hydrogen.

[16] Today, while economics continue to favor hydrogen production via SMR – over production via electrolysers – cost curves for green hydrogen will continue declining rapidly as deployment scales. In contrast, the costs of blue hydrogen will most likely remain at similar levels since the underlying technologies are already mature, and projects in operation today have already achieved scale. Blue hydrogen may, however, be looked at favorably based on future revisions of the EU taxonomy. Hydrogen produced from biogas via SMR may be labeled as green – just like hydrogen produced via electrolysers – which could make SMR investments more attractive.

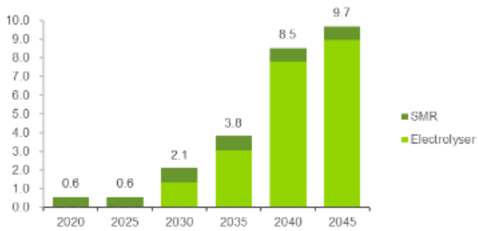
[17] While Sweden does not have CCS storage locations, Sweden is a signatory of the London Protocol, allowing for cross border transportation of CO_2 for underground storage in other jurisdictions.

Hydrogen Imports from mainland Europe partially serve demand in SE4.

While most hydrogen demand is in SE1 and SE3, some share of demand is also found in SE4. SE4 is in a unique position relative to the rest of Sweden given its proximity to a future potential European hydrogen backbone with availability of low-cost green hydrogen production from Spain and/or North-Africa. Initially, hydrogen demand in SE4 is served through domestic hydrogen supplied via electrolysers. However, the availability of low-cost green hydrogen available from the future European hydrogen network triggers the development of an interconnection from Denmark, resulting in hydrogen imports partially supplying hydrogen demand in SE4.

Figure 16 – Hydrogen supply capacity

Region	Annual Supply Capacity (GW)	Highlights



Hydrogen supply capacity increases from 550 MW_{H2} today (only SMR) to 9.7 GW_{H2} by 2045.

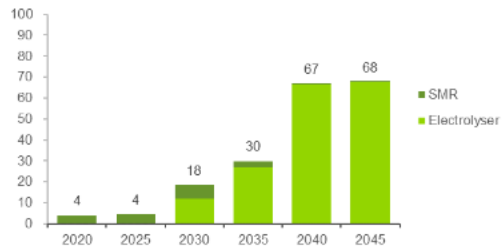
Buildout of electrolyser capacity begins in 2030 and quickly scales up from 2035 to 2040, largely driven by the adoption timeline of HDRI by the steel sector in SE1.

Electrolysers capacity increases from 1.3 GW_{H2} in 2030 to 9.0 GW_{H2} by 2045, equivalent to 12.6 GW_{Elec} of electricity input. SMR capacity increases slightly from 550 MW_{H2} to 750 MW_{H2}.

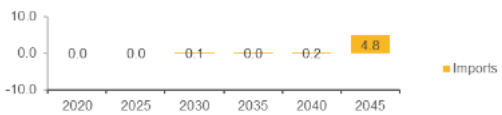
Figure 17 – Annual hydrogen supply

Region	Annual Energy Supply (TWh)	Highlights

Annual Domestic Hydrogen Supply (TWh)



Annual Hydrogen Imports/Exports (TWh)



Hydrogen production via SMR continues to play a role in supplying hydrogen demand until 2040. Blue hydrogen supply remains relevant in locations where hydrogen infrastructure does not develop (e.g., locations not connected to regional hydrogen networks across Sweden).

By 2035, hydrogen production is almost exclusively via electrolysers.

In 2045, hydrogen supply from mainland Europe via Denmark becomes available and is cost-competitive with hydrogen production in Sweden, leading to a small reliance on imports to meet demand in SE4.

Figure 18 – Hydrogen storage capacity

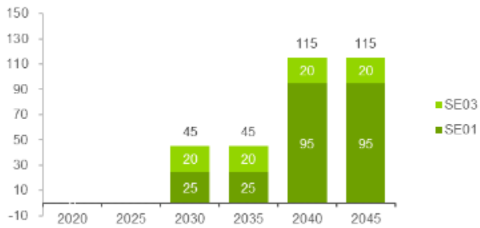
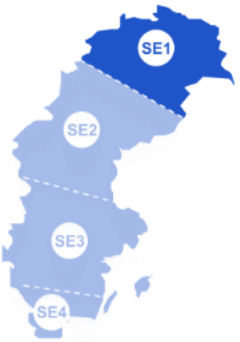
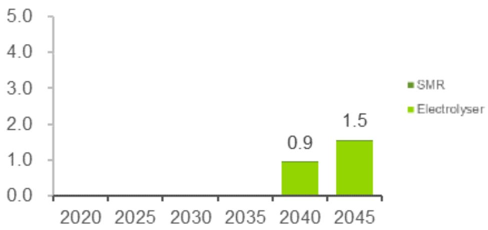
Region	Annual Storage Capacity (GWh)	Highlights
		Storage needs are exclusive to regions with the most hydrogen demand, SE1 and SE3. By 2030, a combined 45 GWh of storage is needed, nearly evenly distributed across SE1 and SE3. By 2045, storage in SE1 grows to 95 GWh, while SE3 remains unchanged. Storage needs in SE3 stagnate because a significant share of hydrogen demand is driven by the transport sector, which is assumed to have a flat demand profile. In comparison, hydrogen demand in industry, which dominates demand in SE1, is subject to some small degree of daily and seasonal variability.

Figure 19 – Hydrogen supply capacity by region

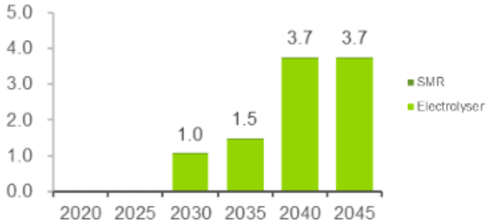
Region	Annual Supply Capacity (GW)	Highlights





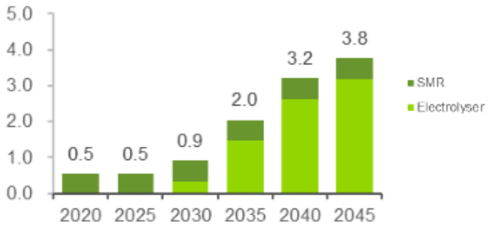
While roughly 50% of hydrogen demand is in SE1, very limited supply capacity is installed here.

Electrolysers used to meet hydrogen demand in SE1 are initially sited in SE2. Only by 2040, when hydrogen demand scales significantly, electrolysers are sited in SE1, reaching 1.5 GW_{H2} by 2045.



There is very limited hydrogen demand in SE2, however, roughly 40% of electrolyser capacity is installed here; reaching 3.7 GW_{H2} by 2045.

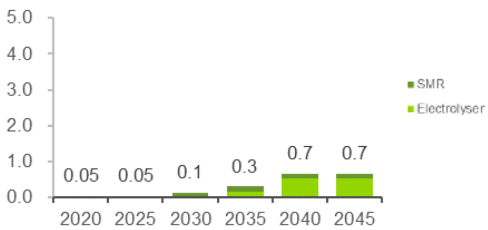
Nearly all hydrogen produced in SE2 is exported to SE1 and SE3.



Nearly all existing SMR capacity is found in SE3 – approximately 500 MW_{H2}. Approximately 100 MW_{H2} of new SMR capacity is built in the future.

The buildout of electrolysers begins in 2030 and is forecast to increase to 3.2G W_{H2} by 2045.

Combined, hydrogen supply capacity in SE3 grows from 0.5 to 3.8 GW_{H2}.



Very limited SMR capacity exists in SE4 today.

As hydrogen demand increases, an additional 100 MW_{H2} of SMR capacity is built. Post-2030, no new SMR capacity is added. The buildout of electrolysers begins in 2030 and reaches 0.5 GW_{H2} by 2045. Combined, hydrogen supply capacity increases from 50 to 700 MW_{H2}.

5.3 Methane supply capacity

Methane supply capacity is forecast to increase from roughly 4 GW today to 5.7 GW by 2045. This increase in supply capacity is exclusively related to domestic capacity of anaerobic digestion (AD) and biomass gasification (bioSNG) plants. Existing import capacity from Denmark, approximately 2.8 GW, is not forecasted to be expanded. Growth in methane supply capacity is driven by increasing gas demand, which is forecasted to increase from 16 TWh today to 29 TWh by 2045.

Increased demand in SE3 and SE4 met via imports and domestic supply.

Most of the growth in methane demand is limited to SE3 and SE4, with only minor increases in methane demand in SE1 and SE2. Up to 2030, most new methane demand continues to be met via methane imports from Denmark. While methane imports increase from approximately 9 to 15 TWh, existing import capacity is sufficient to increase the volume of methane imported from Denmark into SE4 – and then into SE3 – to meet demand. By 2035, methane demand flattens at 29 TWh. However, over time, domestic methane supply scales up and begins to displace the need for imports.

Domestic supply via AD and BioSNG scales post-2030 and post-2040, respectively.

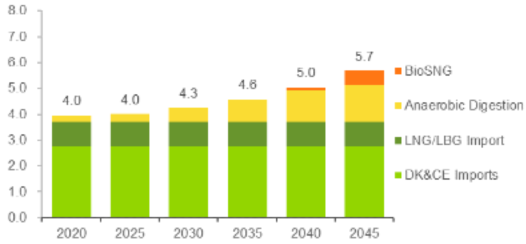
Gas demand peaks in 2035 at 29TWh and does not increase further. While methane imports could continue to supply gas demand, domestic methane production from AD plants and bioSNG scales and displaces some level of imports. By 2045, domestic methane supply meets over 50% of methane demand in Sweden, increasing from approximately 2 TWh today (all via anaerobic digestors) to 17 TWh; 12 TWh from AD and 5 TWh from bioSNG.

Domestic methane supply capacity grows to 2.0 GW.

Domestic methane production begins to scale post-2025, and then rapidly ramps up from 2035 to 2045. Our analysis does not show any new domestic supply capacity in SE4, as methane demand in SE4 continues to rely almost exclusively on methane imports from Denmark. In contrast, SE3 sees significant growth in supply capacity. AD capacity grows to 1.1 GW by 2045, and bioSNG to 400 MW. This scale up gradually displaces reliance on methane imports from Denmark. Proximity to the existing gas grid may be a key enabler of future supply growth, as it gives suppliers access to a large market and lowers distribution / connection costs. In areas/regions that existing gas infrastructure does not reach and is not available in, like SE2 and SE1, supply capacity also scales up, albeit much more limited. AD supply across SE1 and SE2 grows to 250 MW, while bioSNG grows to 200 MW.

Figure 20 – Methane supply capacity

Region	Annual Supply Capacity (GW)	Supply Capacity Buildout



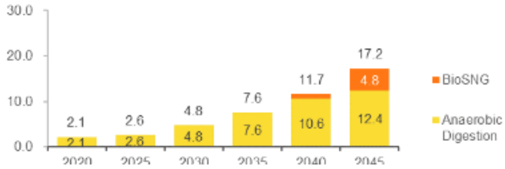
Import capacity from Denmark does not expand remaining at current capacity levels of 2.8 GW

Domestic supply capacity from AD scale significantly post-2030, while BioSNG does not scale until 2040-2045.

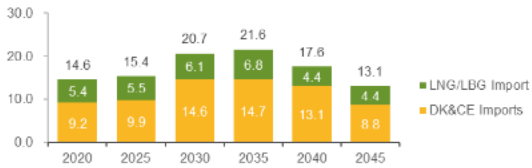
Figure 21 – Annual methane supply

Region	Annual Energy Supply (TWh)	Highlights

Annual Domestic Methane Supply (TWh)



Annual Methane Imports/Exports (TWh)



Domestic methane supply from AD scales significantly post-2030, while BioSNG only scales beginning in 2040.

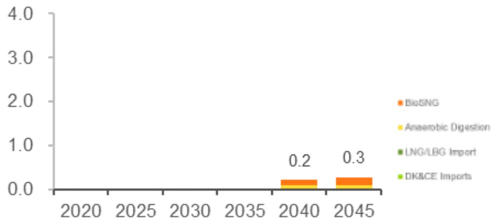
By 2045, domestic supply reaches 17 TWh, 12 TWh from AD and 5 TWh from BioSNG.

Methane imports increase steadily until 2035, reaching 15 TWh, decreasing thereafter back down to current levels, around 9 TWh.

LNG/LBG imports follow a similar trajectory, initially increasing from current levels of 5 to 7 TWh by 2035, and then returning back to current levels.

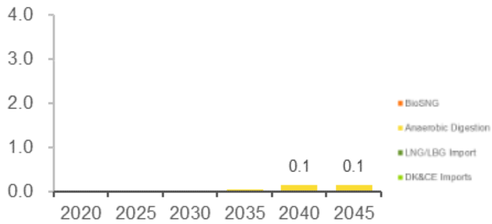
Figure 22 – Methane supply capacity by region

Region	Annual Supply Capacity (GW)	Supply Capacity Buildout

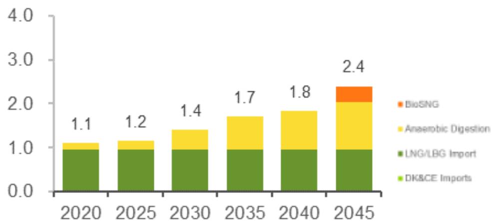


With methane grid infrastructure not extending to SE1, future methane demand is met via domestic supply capacity.

AD supply capacity increases to 100 MW by 2045, while BioSNG capacity increases to 200 MW.

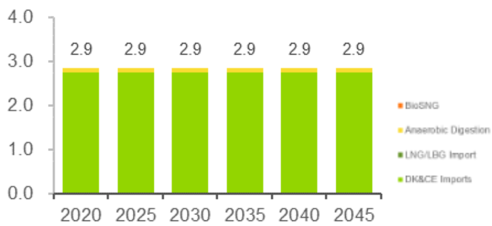


Future methane demand is met exclusively through AD supply capacity, which increases to 150 MW by 2045.



Today, most methane demand in SE3 is met through imports capacity from DK (reported under SE4), LNG imports and some AD capacity.

By 2045, AD supply capacity grows to 1.1 GW while bioSNG grows to 400 MW. LNG/LBG import capacity grows marginally.



Existing import capacity from Denmark meets nearly all methane demand in SE4. Some limited AD capacity also exists in SE4.

No additional supply capacity is forecasted in the future as all new demand can be meet via DK imports.

Chapter 6 Infrastructure Pathways

Transmission infrastructure plays a key role balancing energy supply and demand across regions. While only the electricity system is highly interconnected today, the large buildout of hydrogen and methane supply capacity presented in the previous section demonstrates a clear need for the development of transmission infrastructure across Sweden.

This section presents the optimised infrastructure buildout of electricity, hydrogen, and methane transmission interconnections from today to 2045. Each subsection presents a snapshot of the development of transmission infrastructure over time:

- **Section 6.2** presents a current-day view of energy transmission infrastructure in Sweden as we know it.
- **Section 6.3** fast forwards to 2030 and explores the development of energy i nfrastructure as the transition to low-carbon and renewable energy ramps up and matures.
- **Section 6.4** goes further into the future to 2040, 5-years ahead of the target-date for Sweden to decarbonise, presenting a snapshot of a more developed and integrated system; and
- **Section 6.5** presents a view of a highly interconnected net-zero energy system in 2045.

6.1 Infrastructure development from 2020 to 2045

The development of interconnection infrastructure from 2020 to 2045 varies widely across the electricity, hydrogen, and methane networks. Electricity interconnection infrastructure is strengthened significantly, largely along the DK-SE2 corridor. Meanwhile, we see the emergence of a regional hydrogen backbone along the SE3-SE1 corridor serving hydrogen demand clusters at both ends of the backbone in SE1 and SE3. Finally, while our analysis does not forecast an expansion of existing methane interconnection infrastructure, increased methane demand will be increasingly supplied domestically which will lead to a significant buildout of AD and bioSNG capacity.

Electricity Infrastructure Development

The Swedish electricity transmission network is a highly interconnected system with various regional linkages to Norway, Finland & the Baltics, and Denmark. The transition of the electricity network from today to 2045 is characterised by a significant strengthening of interconnection capacity along the DK-SE2 corridor – the backbone of Sweden's transmission system – delivering supply from SE2, a region with high electricity generation capacity, to demand centers in the south in SE3 and SE4. Interconnections with neighboring countries are also strengthened over time, providing much needed flexibility to the electricity system as onshore and offshore wind capacity scales[18].

This analysis adopts a baseline level of planned interconnection expansions, as defined by the TYNDP National Trends scenario. Much of the interconnection buildout observed in our results is driven by these plans, however, our analysis does trigger additional interconnection expansion in SE3 and SE4.

Hydrogen Infrastructure Development

While there is no existing hydrogen infrastructure today – other than limited SMR capacity and local hydrogen grids at large industries in the south – the transition to 2045 shows large buildout of green hydrogen supply capacity and the development of a regional hydrogen backbone along the SE3-SE1 corridor. Electrolysers begins to scale in 2030 and by 2045, 9.0 GW_{H2} of capacity is installed – equivalent to 12.6 GW of electric input. Approximately half of the electrolyser capacity is installed in SE2, as it develops into a major hub of hydrogen production, serving demand in SE1 and SE3.

Methane Infrastructure Development

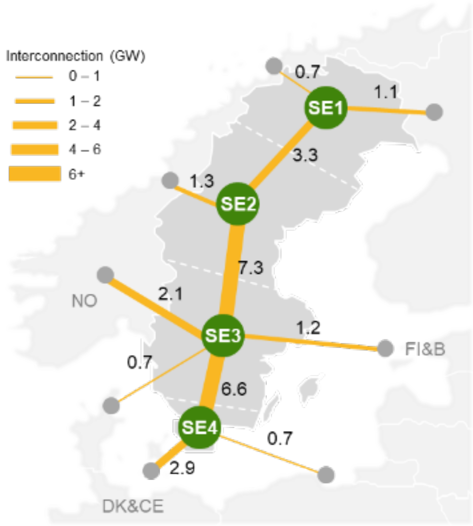
The development of methane infrastructure is relatively limited, with no expansion of the existing interconnections from DK to SE3. This finding is consistent with the lack of plans to expand existing gas infrastructure. TSO plans, as Nevertheless, there is some buildout of domestic methane supply towards the tail-end of the analysis period as anaerobic digestion and bioSNG plants scale post-2030 and post-2040, respectively.

[18] While not explicitly modelled, interconnections to other countries via offshore wind farms ("energy islands") will also develop in the future.

6.2 Interconnection infrastructure in 2020

Figure 23 – Energy infrastructure development in 2020

Electricity Infrastructure Map



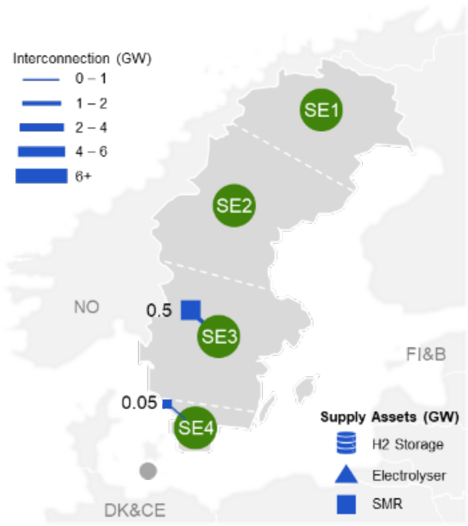
Electricity Infrastructure Development

The Swedish electricity grid in 2020 is already a highly interconnected system with Norway, Finland & the Baltics, and Denmark. Each Swedish region has at least three interconnections with either Swedish or neighboring regions.

This highly interconnected Nordic electricity system gives Sweden an incredible degree of flexibility. This adds to the flexibility provided by the high capacity and availability of hydro reservoirs.

The backbone of the Swedish electricity grid, the DK-to-SE2 corridor, plays a key role in the transfer of electricity from supply-heavy regions to demand centers.

Hydrogen Infrastructure Map

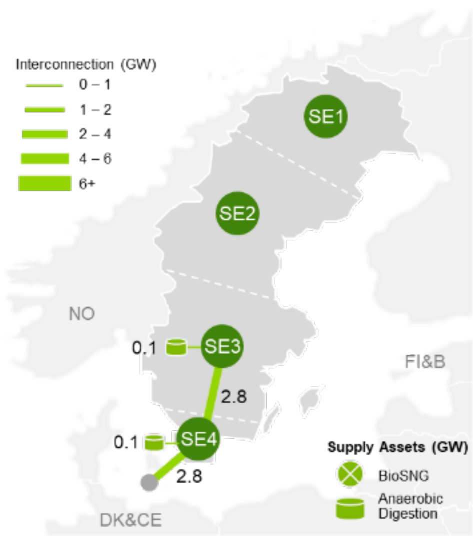


Hydrogen Infrastructure Development

In 2020, no hydrogen infrastructure exists. Some SMR capacity is found in SE4 and SE3 serving existing demand for hydrogen in the chemicals industry and refineries.

Most existing hydrogen supply is produced using natural gas (via SMR)

Methane Infrastructure Map



Methane Infrastructure Development

Existing methane infrastructure extends over approximately 600km from DK into SE4, and then into SE3.

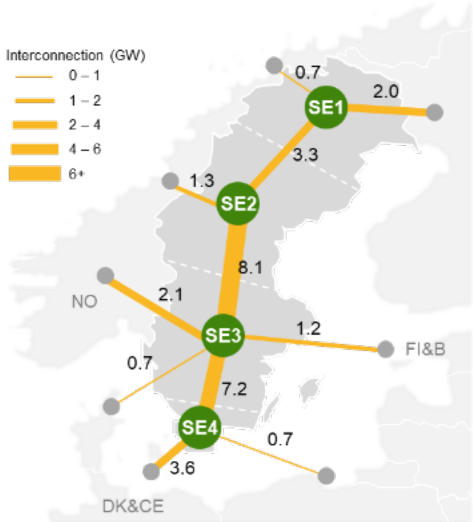
In addition to import capacity from DK, domestic biomethane supply capacity – of approximately 250 MW – also delivers approximately 2 TWh of demand (via anaerobic digestion).

Note: Map not drawn to reality. Region labels are drawn at the geographic centers of each region, rather than at the real location of the gas network.

6.3 Interconnection infrastructure in 2030

Figure 24 – Energy infrastructure development in 2030

Electricity Infrastructure Map



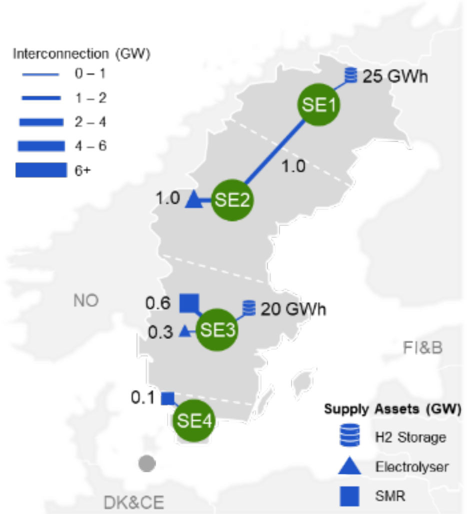
Electricity Infrastructure Development

By 2030, interconnections between Swedish regions and with neighboring regions have expanded. Notably, all interconnections along the DK-to-SE2 corridor, the backbone of Sweden's transmission system, expand:

- The DK&CE-SE4 interconnection expands from 2.9 to 3.6 GW.
- The SE4-SE3 expands from 6.6 to 7.2 GW; and
- The SE3-SE2 expands from 7.3 to 8.1 GW.

Among international interconnections, other than DK&CE-SE4, only SE1-FI&B expands; from 1.1 to 2.0 GW

Hydrogen Infrastructure Map



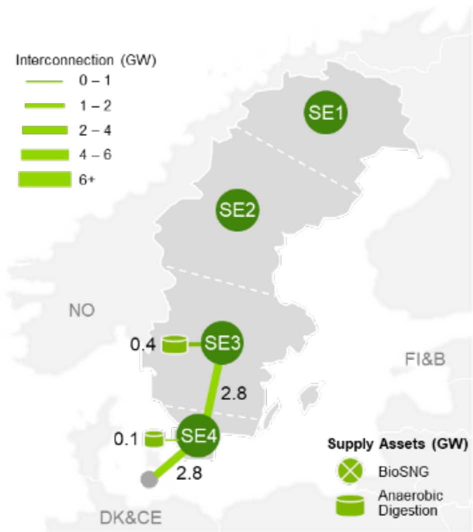
Hydrogen Infrastructure Development

By 2030, hydrogen infrastructure begins to develop in the north of Sweden, serving the steel & mining industry cluster developing in SE1.

An SE2-to-SE1 interconnection corridor of 1.0 GW$_{H2}$ develops, with 1.0 GW$_{H2}$ of electrolyser capacity installed in SE2. Hydrogen produced in SE2 is deliver via pipeline northbound to the industry cluster in SE1. Approximately 25 GWh of hydrogen storage is installed in SE1 to optimise the supply of hydrogen.

In SE3, 0.3 GW$_{H2}$ of electrolyser capacity is installed to meet demand, along with 20 GWh of storage. New additional SMR capacity is installed in both SE3 and SE4, increasing to 100 MW$_{H2}$ and 600 MW$_{H2}$ respectively.

Methane Infrastructure Map



Methane Infrastructure Development

By 2030, methane infrastructure remains unchanged. While more gas volumes are delivered from DK to SE4 and SE3, the existing interconnection infrastructure serves most of the increasing demand.

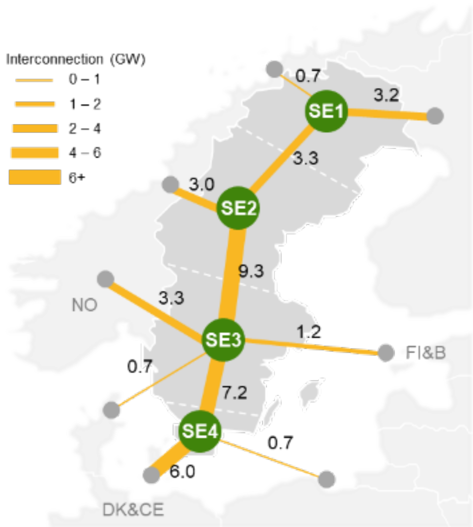
By 2030, the blend of fossil gas and biomethane delivered from Denmark has drastically shifted, with the share of gas supply largely weighted to biomethane.

In SE3, AD supply capacity increasing from 100 to 400 MW.

6.4 Interconnection infrastructure in 2040

Figure 25 – Energy infrastructure development in 2040

Electricity Infrastructure Map



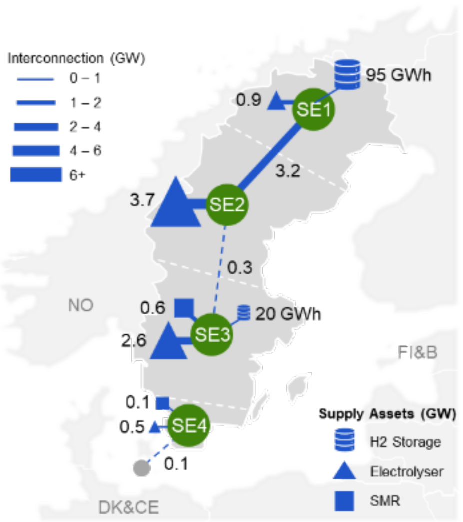
Electricity Infrastructure Development

By 2040, interconnections between Swedish regions and with neighboring regions continue to strengthen and expand. Sections of the DK-to-SE2 corridor expand further, enabling increasing flows of electricity across regions:

- The DK&CE-SE4 interconnection expands from 3.6 to 6.0 GW.
- SE3-SE2 expands from 8.1 to 9.3 GW; and
- SE4-SE3 expands from 7.2 to 10.6 GW.

Interconnections with Norway (from SE2 and SE3) and with FI&B (from SE1) also expand.

Hydrogen Infrastructure Map



Hydrogen Infrastructure Development

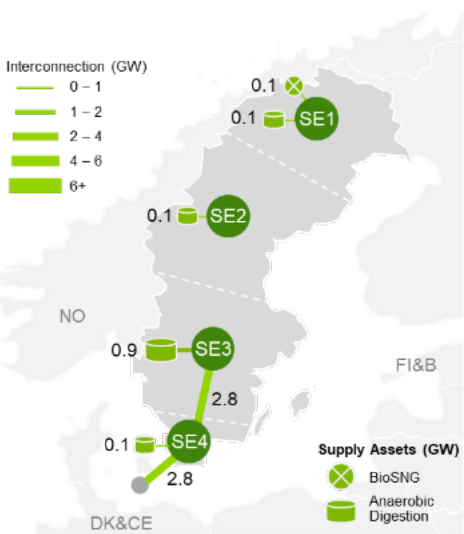
By 2040, a very clear regional hydrogen backbone from SE2-to-S1 has developed and begins to extend southbound to SE3. Hydrogen storage needs in SE1 increase from 25 to 95 GWh as hydrogen demand increases.

The buildout of electrolyser capacity in the north of the country continues to scale. Electrolysers capacity in SE2 increases significantly from 1.0 to 3.7 GW_{H2}. as SE2 becomes a major hub of hydrogen production, primarily serving demand in SE1, and to a more limited extent SE3.

Electrolyser capacity in SE3 increases rapidly, from 0.3 to 2.6 GW_{H2}, to supply increasing demand in SE3.

A **dotted line** is used to denote *weak* interconnections (less than 0.5 GW) and the underlying uncertainty around their development.

Methane Infrastructure Map



Methane Infrastructure Development

By 2040, methane infrastructure remains unchanged. Domestic supply capacity of anaerobic digestion and biomass gasification scales.

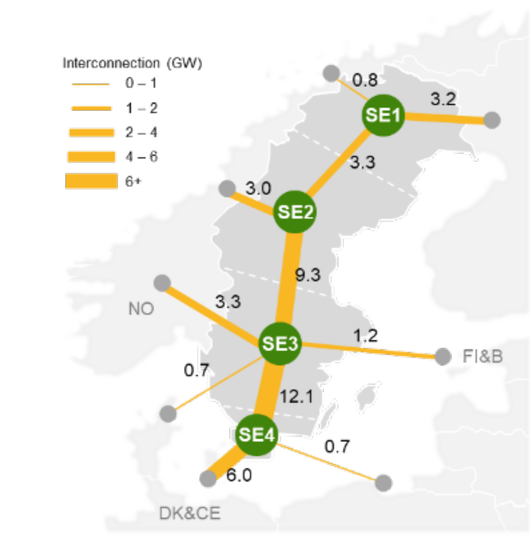
AD capacity scales in SE3 from 400 MW to 900 MW. In the north, as demand for methane emerges, AD and bioSNG supply capacity grows. In SE1, AD and bioSNG capacity grows to 100 MW each, while in SE2, only new AD is needed, growing to 100 MW.

In SE1 and SE2, the reality of local conditions and the availability of biomass may result in the development of bioSNG instead of AD.

6.5 Interconnection infrastructure in 2045

Figure 26 – Energy infrastructure development in 2045

Electricity Infrastructure Map

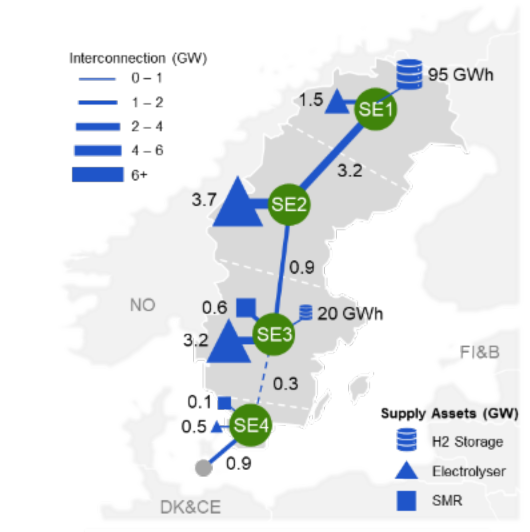


Electricity Infrastructure Development

From 2040 to 2045, the buildout of interconnection infrastructure is limited to the south of Sweden in SE3 and SE4 where offshore wind capacity continues to scale.

By 2045, all available headroom in interconnection capacity along the SE3-SE4 corridor is utilised, and new offshore capacity triggers the need for interconnection reinforcements. The SE3-SE4 interconnection expands significantly from 10.2 GW to 12.8 GW. This increase in interconnection capacity may, in reality, be more subtle as large-scale offshore wind projects may also be connected to neighboring countries.

Hydrogen Infrastructure Map



Hydrogen Infrastructure Development

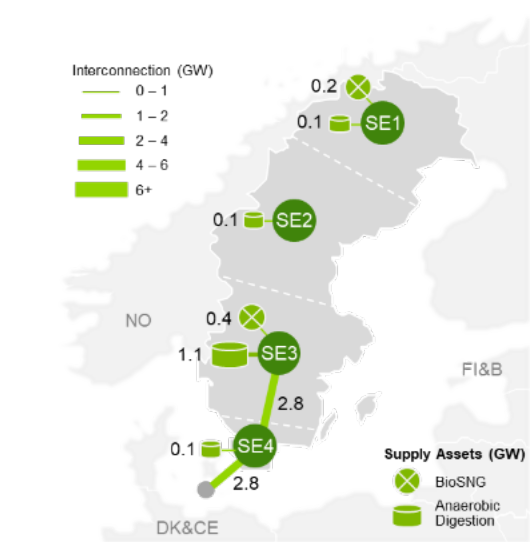
By 2045, a very clear regional backbone from SE3-to-SE1 has developed. The SE1-SE2 interconnection does not expand beyond 2040, as the decarbonisation of the steel & mining industrial cluster in SE1 is completed.

Nevertheless, additional electrolyser capacity is installed in SE1, increasing from 0.9 to 1.5 GW_{H2}, slightly displacing hydrogen imports from SE2.

While growth in hydrogen demand in SE1 stalls, demand continues to grow in SE3. This leads to an expansion of the SE3-SE2 interconnection from 0.3 to 0.9 $GW_{H2,}$ as well as increased electrolyser capacity from 2.6 GW_{H2} to 3.2 GW_{H2}.

In 2045, the DK&CE-SE4 interconnection strengthens, partially supplying demand in SE4. A weak SE4-SE3 link also develops

Methane Infrastructure Map



Methane Infrastructure Development

By 2045, methane demand has flattened. Despite this, the buildout of methane supply capacity via AD and BioSNG continues to expand, as domestic production displaces methane imports from DK. This leads to import volumes from DK decreasing back down to current day levels of around 9 TWh.

BioSNG capacity scales further in SE1, increasing from 200 MW. In SE3, supply capacity of AD increases from 900 to 1.1 GW while bioSNG capacity grows to 400 MW.

Since existing gas infrastructure was able to cope with higher demand levels experienced in previous years, no expansion of interconnection capacity is ever needed. This is consistent with the lack of any plans to further expand the gas transmission network.


Nämforsen Power Plant

Chapter 7

Stress-Testing the Role of Gas Infrastructure

Previous sections explored the development of electricity, hydrogen and methane transmission infrastructure based on the Major Role for Gas scenario. In that scenario, demand for hydrogen and methane were projected to increase significantly to 66 TWh and 29 TWh, respectively.

In this section, we adopt alternative decarbonisation pathways to stress-test the role played by gas infrastructure in different future visions of the Swedish energy system. This section concludes by qualitatively exploring two hypothetical scenarios in which Sweden serves as a hydrogen production hub to neighboring regions.

- **Section 7.1** explores the impact on gas infrastructure from adopting the Limited Role for Gas scenario. In this scenario, future demand for hydrogen and methane is more conservative than in the Major Role for Gas scenario, with electrification and liquid biofuels becoming more prominent decarbonisation options. This section also compares the total investments required in hydrogen and methane supply and infrastructure across both scenarios.

- **Section 7.2** introduces various sensitivity scenarios to further stress-test the role played by gas infrastructure in the energy system:
  - **Section 7.2.1** explores the impact of low-cost hydrogen imports.
  - **Section 7.2.2** explores the impact of low hydrogen infrastructure costs.
  - **Section 7.2.3** explores the impact of low electrolyser costs.
  - **Section 7.2.4** explores the impact of an extended nuclear fleet (beyond 60 yrs.); and
  - **Section 7.2.5** explores the impact of an alternate demand scenario in which electricity and hydrogen demand are significantly higher than in the Major Gas scenario.

- **Section 7.3** explores two hypothetical scenarios in which Sweden serves as a hydrogen production hub to neighboring regions; one in which Sweden supplies hydrogen to mainland Europe via Denmark, and a second one, in which an interconnection with Finland develops and Swedish hydrogen can be used to supply Finish demand.

7.1 Demand scenario: Limited Role for Gas

In the Limited Role for Gas scenario, hydrogen and methane play a more limited role in all demand sectors, compared to the Major Role for Gas scenario.

- In **buildings**, the use of methane for gas heating is displaced by electric heat pumps.
- In **transport**, light and heavy road transport are largely electrified, with only a limited role for bio-CNG/LNG in trucks. in shipping, while bio-LNG still plays a role, hydrogen-derived ammonia and methanol do not. In aviation, there is not change compared to the Major Role for Gas scenario, with e-kerosene (sourced from hydrogen) plays the same role.
- In **industry**, while hydrogen demand is consistent in both scenarios, methane demand drops.

7.1.1 Impact on gas demand

Overall, gas volumes drop by 33 TWh by 2045, equivalent to a 34% reduction in gas volumes. These drops in gas demand are presented by the figures below. Individually, hydrogen demand drops 18 TWh, from 68 down to 50TWh, equivalent to a 24% reduction, while methane demand drops 15 TWh, from 29 TWh down to 14 TWh, a reduction of 52%.

It is worth noting that the reduction in hydrogen demand has a very unique regional dimension. Since the LKAB decarbonisation via HDRI is assumed to materialise in both demand scenarios, hydrogen demand does not drop in SE1, where the steel and mining hydrogen cluster is located. Rather, the reduction in hydrogen demand is limited to the south of the country, primarily in SE3, and to a more limited extent in SE4. This regional dimension in the reduction of hydrogen demand will have a very direct impact on the development of hydrogen infrastructure in the Limited Role for Gas scenario.

The reduction in hydrogen demand has an associated impact on electricity demand, however, as this scenario also sees an increased role for electrification, the impact is more muted. Electricity demand only drops 13 TWh from 253 down to 241 TWh, a 5% reduction.

Figure 27 – Hydrogen demand, demand scenario 2, Limited Role for Gas

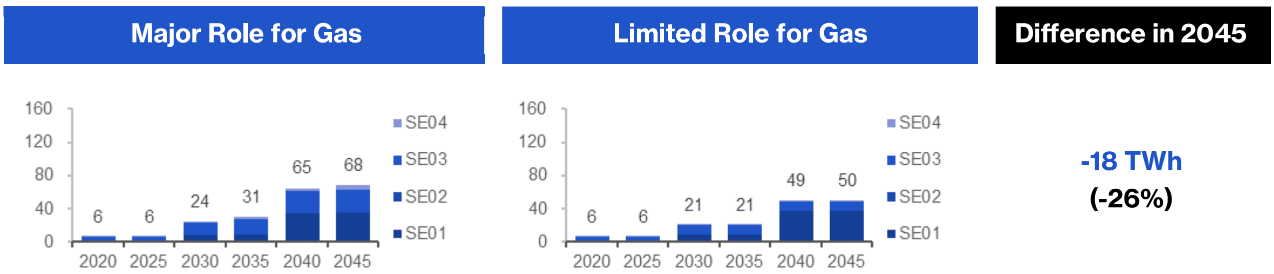
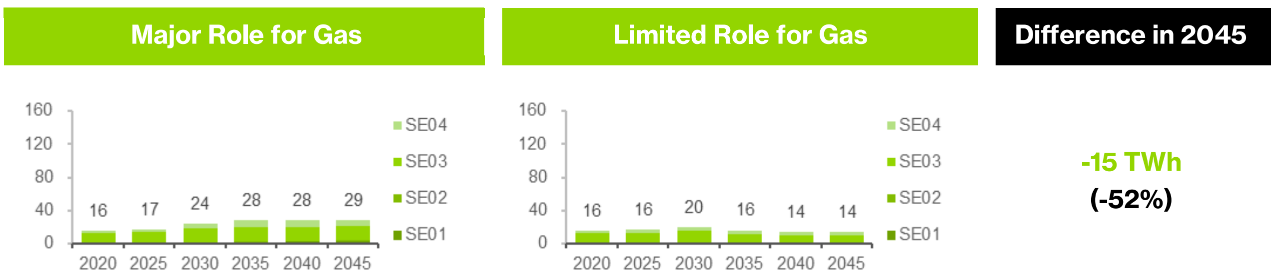


Figure 28 – Methane demand, demand scenario 2, Limited Role for Gas



7.1.2 Impact on gas infrastructure

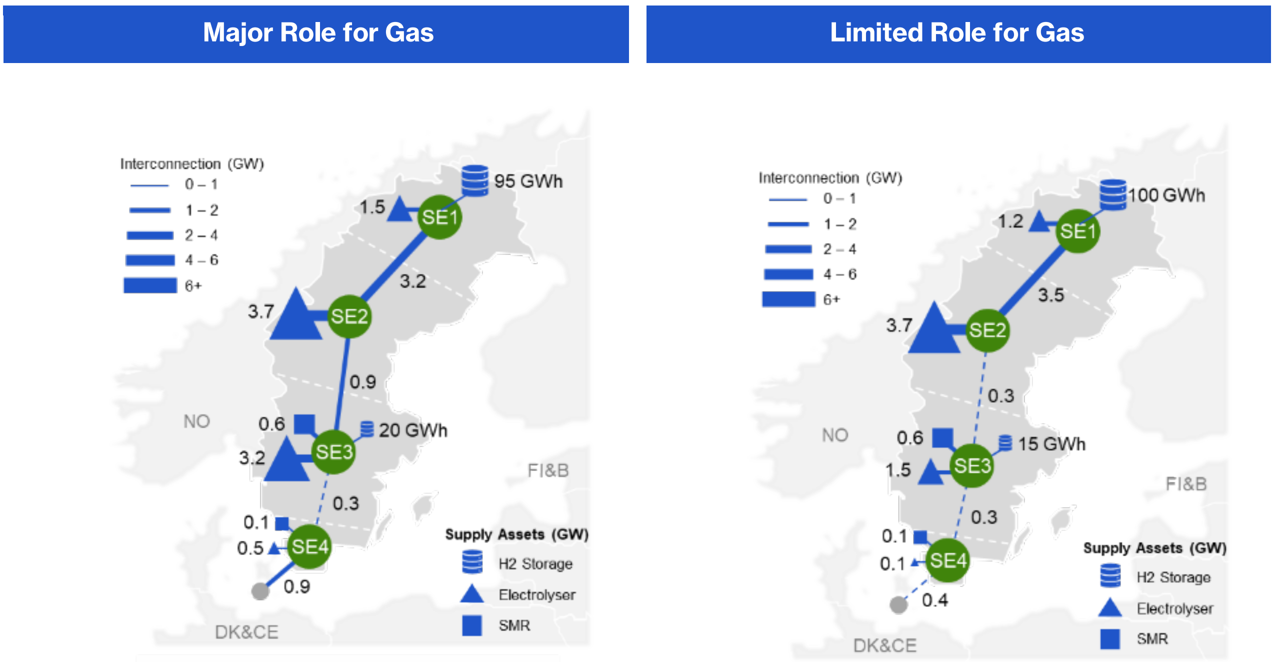
The 34% drop in gas volumes (hydrogen and methane) result in a more limited buildout of hydrogen and methane infrastructure and supply capacity.

The 2045 snapshots of hydrogen infrastructure in both scenarios are presented below. The reduction in hydrogen volumes has a noticeable impact on the development of the SE3-SE1 hydrogen corridor, compared to the Major Role for Gas scenario. The SE3-SE2 interconnection – which in the Major Role for Gas scenario is used to deliver hydrogen from SE2 to SE3 – becomes visibly weaker. SE2 no longer plays the role of a "hydrogen production hub" for SE3. Electrolyser capacity in SE3 significantly drops from 3.5 down to 1.5 GW_{H2}. The weakening of the SE3-SE2 interconnection and the drop in SE3 electrolyser capacity is a direct result of the large reduction in hydrogen demand in SE3.

In contrast to the SE2-SE3 dynamics, the SE2-SE1 interconnection is strengthened. As described above, hydrogen demand in SE1 is unchanged since the adoption of HDRI by LKAB is assumed to also materialise in the Limited Role for Gas scenario. As a result, the impact on the development of hydrogen infrastructure in the north is almost negligible. While electrolyser capacity in SE1 drops slightly from 1.5 down to 1.2 GW_{H2}, this triggers an increase in the need for hydrogen supply from SE2, which in turn leads to an increase in the SE2-SE1 interconnection capacity, with more hydrogen being transported from SE2 to SE1.

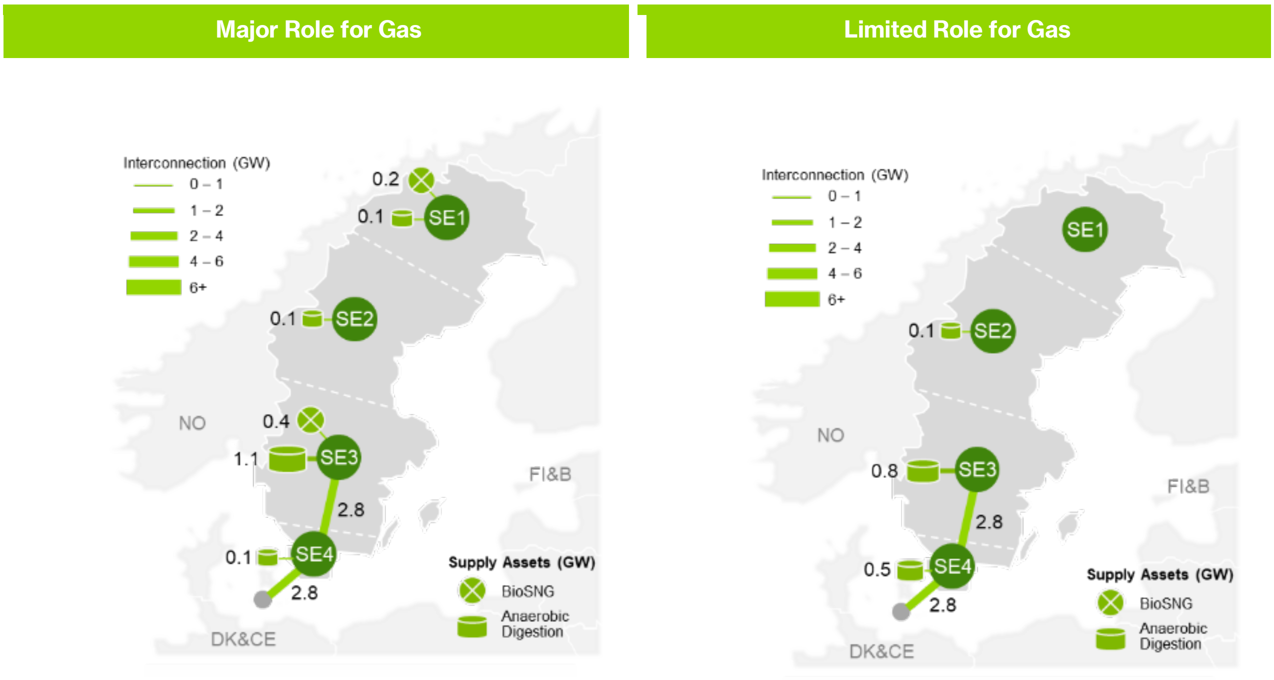
In SE4, as hydrogen demand dwindles in the sensitivity scenario, the development of hydrogen infrastructure weakens. Electrolyser capacity in SE4 decreases from 0.5 to 0.1 GW_{H2}, rather relying on hydrogen imports from DK&CE and already-existing SMR capacity.

Figure 29 – Hydrogen infrastructure in 2045, demand scenario 2, Limited Role for Gas



The reduction in methane demand in the Limited Role for Gas scenario has a limited impact on methane infrastructure. Existing interconnection capacity from DK&CE to SE4 and further into SE3 is untouched as methane demand remains at current-day levels. The buildout of methane supply capacity is much more limited compared to the Major Role for Gas scenario with both AD and bioSNG capacity both dropping.

Figure 30 – Methane infrastructure in 2045, demand scenario 2, Limited Role for Gas



7.1.3 Comparison of gas supply and infrastructure costs

The level of investment in new gas supply and infrastructure capacity required in each demand scenario is primarily driven by the quantity of gas produced and transported through the gas networks. The Major Role for Gas scenario leads to significantly more hydrogen and methane investments than the Limited Role for Gas scenario.

Before exploring in detail the magnitude of the required investment in gas supply and infrastructure, this section begins by first describing the approach used to determine investments in hydrogen infrastructure.

Estimating investments in hydrogen infrastructure

The calculation of hydrogen infrastructure costs is initially based on the costs of building the hypothetical hydrogen network developed by each scenario by 2045. For example, in the Major Role for Gas scenario, this means that the calculation of hydrogen infrastructure costs is based on the following pipeline interconnection capacities (and distances) across regions:

- A 3.2 GW hydrogen pipeline from SE1 to SE2 over 400 km.
- A 0.9 GW hydrogen pipeline from SE2 to SE3 over 500 km.
- A 0.3 GW hydrogen pipeline from SE3 to SE4 over 300 km, and
- A 0.9 GW hydrogen pipeline from SE4 to DK over 200 km.

These pipeline capacities represent the bare minimum capacity required to meet the hydrogen transport needs and demand of the 2045 energy system. In other words, these pipeline capacities are sized to perfectly meet hydrogen demand.

In reality, however, a gas TSO would not size a pipeline to perfectly meet demand. Pipelines would be oversized and built with a much longer-term view of future hydrogen demand. Further, since there is only a subset of standard pipeline sizes that are commercially available, a gas TSO would have to build their hydrogen network based on those standard pipeline sizes. The most common pipeline sizes include the following:

- 20-inch (allowing up to 1.2 GW of capacity).
- 36-inch (allowing up to 4.7 GW of capacity), or
- 48-inch (allowing up to 13 GW of capacity).

Since gas TSOs are likely to be limited to these pipeline sizes, building hydrogen infrastructure based on the "minimum capacities" presented previously is not realistic. To develop a realistic estimate of hydrogen infrastructure costs, we determine the most appropriate pipeline size for each pipeline segment. The table below shows the result of this exercise.

- For the **Major Role for Gas scenario**, a 4.7 GW (36-inch) pipeline is taken as the most appropriate pipeline size for 3 of the 4 pipeline segments: the 3.2 GW segment (SE1-SE2) and the 0.9 GW segments (SE2-SE3 and DK-SE4). A 36-inch pipeline is adopted for the 0.9 GW segments because a 20-inch (1.2 GW) pipeline would only leave very narrow headroom for additional capacity. For the last segment, the 0.3 GW segment (SE3-SE4), a 20-inch pipeline is taken as the most appropriate pipeline size.
- For the **Limited Role for Gas scenario**, a 4.7 GW (36-inch) pipeline is taken for only 1 of the 4 segments: the 3.5 GW segment (SE1-SE2). Meanwhile, a 1.2 GW (20-inch) pipeline is taken as the appropriate pipeline size for the remaining 3 pipeline segments: the 0.3 GW segments (SE2-SE3 and SE3-SE4) and the 0.4 GW segment (DK-SE4).

Table 4 – Minimum & Standard Hydrogen Pipeline Capacities by Segment

	Major Role for Gas		Limited Role for Gas	
	Minimum Capacities	Standard Capacities	Minimum Capacities	Standard Capacities
SE1-SE2	3.2 GW	4.7 GW [36-inch]	3.5 GW	4.7 GW [36-inch]
SE2-SE3	0.9 GW	4.7 GW [36-inch]	0.3 GW	1.2 GW [20-inch]
SE3-SE4	0.3 GW	1.2 GW [20-inch]	0.3 GW	1.2 GW [20-inch]
DK-SE4	0.9 GW	4.7 GW [36-inch]	0.4 GW	1.2 GW [20-inch]

Note: The "minimum capacity" columns show the pipeline capacities determined by our analysis, while the "standard capacity" columns shows the candidate pipeline capacities deemed to be most appropriate based on the set of standard pipelines listed above.

We use these standard pipeline capacities for each segment to develop a realistic estimate of the level of investment required in hydrogen infrastructure for each demand scenario.

To calculate hydrogen infrastructure costs (€), we apply the per-unit hydrogen pipeline costs estimated in Table 21 to the pipeline capacities (GW) and distances (km) estimated for each pipeline segment. The per-unit cost for 36-inch (4.7 GW) pipeline segments is to €536 /MW-km, while for 20-inch (1.2 GW) pipeline segments, this corresponds to €1,325 /MW-km. On a per-unit basis, 20-inch pipelines are much more expensive than 36-inch pipeline because capital costs and hydrogen volumes transported do not scale proportionally; while capital costs decrease slightly, the quantities of hydrogen transported decrease more significantly.

In this next section, we present the aggregated investments in hydrogen supply and infrastructure for the Major Role for Gas scenario and the Limited Role for Gas scenario.

Investments in hydrogen supply & infrastructure capacity

The Major Role for Gas scenario leads to a period of sustained investments in hydrogen infrastructure from 2030 to 2040, over which investments consistently reach over €1.5 billion in each of the post-2030 milestone years – 2030, 2035, 2040 and 2045. Total investment in hydrogen supply and infrastructure is €8.3 billion cumulative across all milestone years.

The timeline of investments is primarily driven by the scale up in electrolyser capacity in SE1, SE2 and SE3. Investments in electrolyser capacity account for approximately 60% of total spent, or €4.9 billion cumulative over the milestone years. Investment in hydrogen interconnection infrastructure – which reflects the costs of hydrogen pipelines and compressor stations – follow a similar timeline as electrolyser investments and account for roughly 40% of total spent, or €3.3 billion. Investments in SMR are relatively limited compared to investments in electrolysers and infrastructure and account for €0.1 billion.

In comparison, hydrogen investments in the Limited Role for Gas scenario are more limited – though still quite significant. Total investment in hydrogen supply and infrastructure amount to €6.2 billion across all milestone years, equivalent to 25% lower than in the Major Role for Gas scenario. Hydrogen infrastructure costs amount to €2.6 billion, approximately 20% lower than in the Major Role for Gas scenario.

The magnitude of investments in 2030 and 2040 are very similar across both scenarios: €1.7 and €3.6 billion in the Major Role for Gas scenario, compared to €1.5 and €3.3 billion in the Limited Role for Gas scenario. This is because investments in 2030 and 2040 are driven by the decarbonisation timeline for the steel sector to transition to the HDRI process, which is assumed to occur in both scenarios. In comparison, the impact on hydrogen investments in 2035 and 2045 is much more significant.

How to interpret investments in gas supply and infrastructure?

CAPEX and OPEX

The timeline of investments presented below represent capital and operating expenditures (CAPEX and OPEX) from the perspective of an energy infrastructure developer. CAPEX and OPEX costs reflect all technology costs associated with deploying and operating the different gas supply technologies – e.g., electrolysers, SMR, AD and bioSNG – as well as costs associated with gas interconnection infrastructure – e.g., pipelines and compressors stations.

Milestone Years vs. Intervening Years

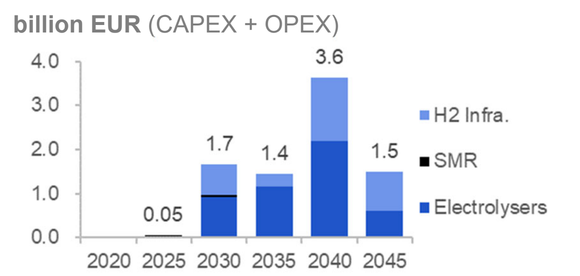
CAPEX and OPEX cost figures reported are specific to each milestone year. Based on our modelling approach, the deployment of supply capacity and infrastructure can only occur in milestones year – e.g., 2025, 2030, 2035, 2040 and 2045. As a result, CAPEX costs are only incurred in milestone years and not in intervening years. OPEX costs, however, also occur in intervening years. While OPEX costs from intervening years – e.g., OPEX costs from 2026, 2027, 2028 and 2029 – are captured as part of the cost-optimisation in our modelling approach, these intervening-year OPEX costs are not included in the investment costs reported by the figures below.

Feedstock Costs

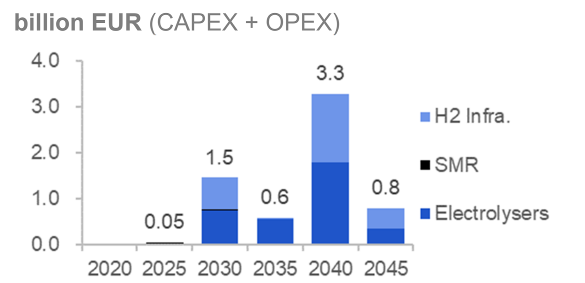
OPEX costs reported by the figures below do not capture the costs of feedstock used in the production of hydrogen or methane (e.g., the cost of electricity used in the production of hydrogen via electrolysers, or the cost of biomass feedstock used to produce bioSNG). Much like intervening-year OPEX costs, feedstock costs are also captured in our modelling approach. For reporting purposes, however, they are not captured as part of OPEX costs because those costs would not be incurred by an energy infrastructure developer.

Figure 31 – Investment in hydrogen supply and infrastructure (2020-2045)

Major Role for Gas



Limited Role for Gas



Hydrogen Investment (billion EUR) – Major Role for Gas

	2025	2030	2035	2040	2045	Total
Electrolyser	-	0.9	1.2	2.2	0.6	**4.9**
SMR	0.05	0.1	-	-	-	**0.1**
H2 Infra.	-	0.7	0.3	1.4	0.9	**3.3**
Total	**0.05**	**1.7**	**1.4**	**3.6**	**1.5**	**8.3**

Hydrogen Investment (billion EUR) – Limited Role for Gas

	2025	2030	2035	2040	2045	Total
Electrolyser	-	0.7	0.6	1.8	0.4	**3.5**
SMR	0.05	0.1	-	-	-	**0.1**
H2 Infra.	-	0.7	0.0	1.5	0.4	**2.6**
Total	**0.05**	**1.5**	**0.6**	**3.3**	**0.8**	**6.2**

Investments in methane supply capacity

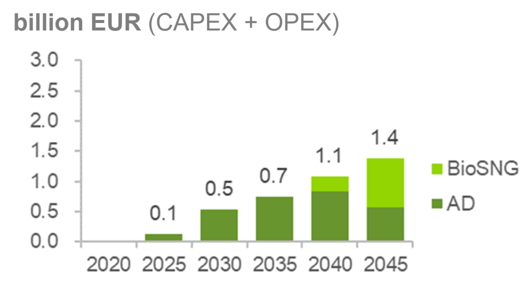
Investments in methane supply capacity are more limited in the Limited Role for Gas scenario compared to the Major Role for Gas scenario. Unlike investments in hydrogen which were relatively consistent in magnitude from 2030 to 2045 – other than in 2040 – investments in methane supply capacity ramp up steadily beginning in 2025.

In the Major Role for Gas scenarios, the ramp up of investment in AD supply is followed by a ramp up in bioSNG supply. The scale up of AD and bioSNG supply capacity leads to over €1 billion in investment in 2040 and 2045. In contrast, in the Limited Role for Gas scenario, with relatively flat demand for methane over the forecast period, there is no scale up of investments in bioSNG supply.

As previously discussed, neither scenario leads to an expansion of existing interconnection infrastructure from DK, hence no investments in methane interconnection infrastructure are reported.

Figure 32 – Investment in methane supply (2020-2045)

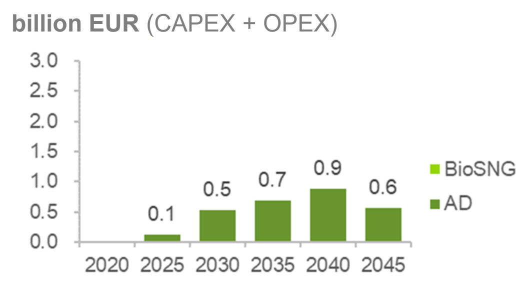
Major Role for Gas



Methane Investment (billion EUR)

	2025	2030	2035	2040	2045	Total
AD	0.1	0.5	0.7	0.8	0.6	**2.8**
BioSNG	-	-	-	0.3	0.8	**1.1**
Methane Infra.	-	-	-	-		-
Total	**0.1**	**0.5**	**0.7**	**1.1**	**1.4**	**3.8**

Limited Role for Gas



Methane Investment (billion EUR)

	2025	2030	2035	2040	2045	Total
AD	0.1	0.5	0.7	0.9	0.6	**2.8**
BioSNG	-	-	-	-		-
Methane Infra.	-	-	-	-		-
Total	**0.1**	**0.5**	**0.7**	**0.9**	**0.6**	**2.8**

7.2 Sensitivity analysis

In previous sections, we explored the role of gas supply and gas based on two potential scenarios of energy demand, a Major Role for Gas and the Limited Role for Gas scenarios. As with any analysis attempting to model a future integrated energy system, both scenarios are subject to significant uncertainty. In this section, we explore the impact of several pathway uncertainties and challenges on gas supply and gas infrastructure.

Figure 33 – Description of sensitivity scenarios

	Sensitivity	Rationale
1	**Low H_2 Import Costs**	Investigate the impact of lower import costs of hydrogen on the development of hydrogen supply and infrastructure.
2	**Low H_2 Infrastructure Costs**	Investigate the impact of lower cost of hydrogen transmission infrastructure – pipelines and compressors – on the development of hydrogen supply and infrastructure
3	**Low Electrolyser Costs**	Investigate the impact of lower costs and higher efficiency of electrolyser on the development of hydrogen supply and infrastructure
4	**Future Role of Nuclear Energy**	Investigate the impact of an expanded lifetime of the nuclear fleet on the development of hydrogen supply and infrastructure, and the power system.
5	**Higher Electricity & H_2 Demand**	Investigate the impact of higher forecasts of electricity and hydrogen demand in high-growth sectors – like steel and iron-ore mining and data centers – on the development of hydrogen supply and infrastructure

7.2.1 Sensitivity 1: Low H_2 import costs

Sensitivity drivers

In the Low H_2 Import Cost sensitivity, we adopt a more price-aggressive forecast of hydrogen import costs available via Denmark. The premise of this sensitivity is based on the development of a full European hydrogen backbone that allows cheap green hydrogen imports from North Africa to complement hydrogen production in Spain.

In our Major Role for Gas scenario, we adopted a baseline forecast of hydrogen import costs decreasing from €85/MWh in 2030 down to €55/MWh by 2045. In this sensitivity, we adopt a price forecast resulting in hydrogen import costs 30% lower than the baseline, with costs decreasing from €76/MWh in 2030 down to €40/MWh by 2045.

Figure 34 – Comparison of H_2 import costs

EUR/MWh	2030	2035	2040	2045
Base	85	75	65	55
Low H_2 costs	76	63	51	40

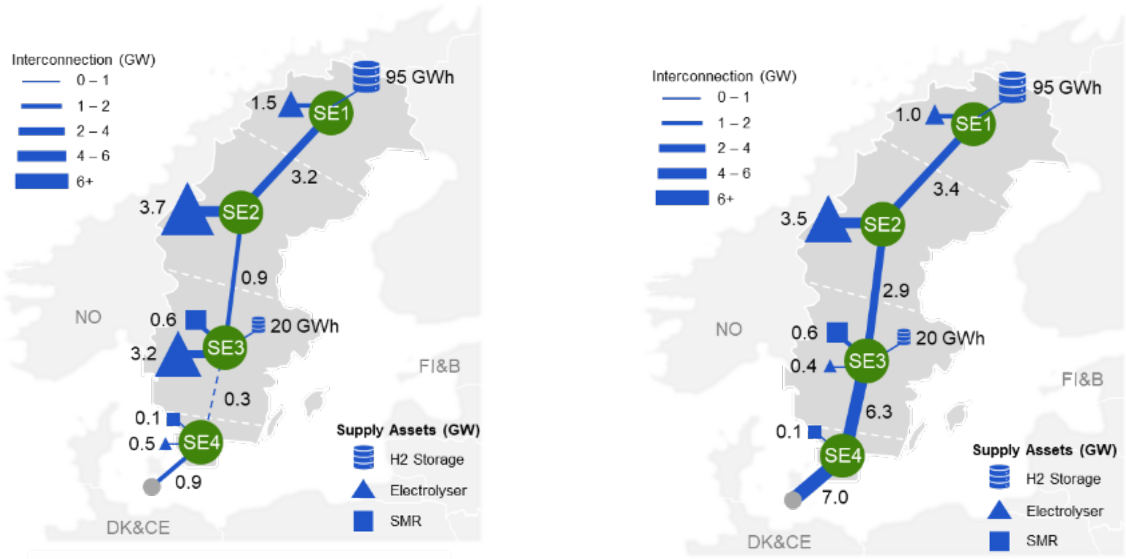
Impact on gas infrastructure development

The impact from low hydrogen import costs in the development of hydrogen infrastructure is drastic. The availability of cheap hydrogen via Denmark leads to the buildout of a complete national hydrogen backbone stretching from DK to SE1. Hydrogen import capacity expands from 0.6 GW, in the Major Role for Gas scenario, to 7.0 GW in this sensitivity. This increase in import capacity allows for cheap hydrogen imports to supply most hydrogen demand in Sweden. While in the Major Role for Gas scenario, hydrogen imports supplied approximately 5% of demand, in this sensitivity more than 75% of demand is supplied by imports.

As a result of the reliance on cheap hydrogen imports via Denmark, electrolyser capacity installed across all Swedish regions decreases, decreasing from 9.0 GW_{H2}, in the Major Role for Gas scenario, down to 4.9 GW_{H2}. Significant electrolyser capacity is still deployed in the north of the country in SE2 and SE1. However, as hydrogen supply becomes more and more reliant on hydrogen imports over time, roughly half of the installed electrolyser capacity – built in earlier years to meet hydrogen demand – becomes stranded. This is illustrated below by the changing hydrogen supply mix over time, in the Low H_2 Import Costs sensitivity, which shows supply from electrolysers peaking in 2040 at around 40 TWh, before falling back down to less than 20 TWh.

Figure 35 – Hydrogen infrastructure in 2045, Sensitivity 1, Low H_2 import costs

Major Role for Gas	Low H_2 Import Costs



Hydrogen Supply Capacity in 2045 (Major Role for Gas)

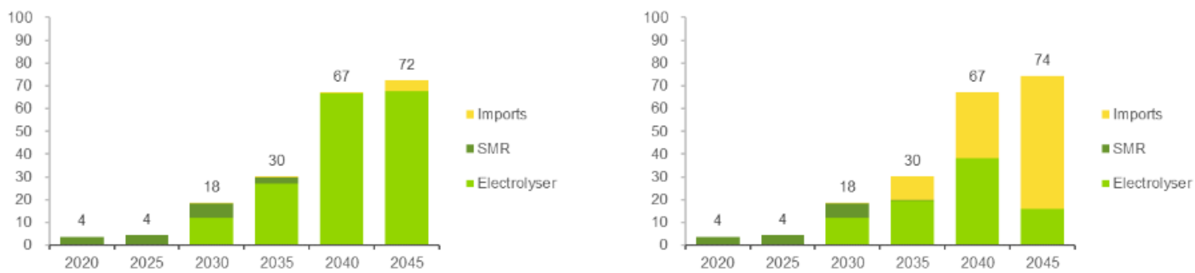
Scenario	GW
Electrolysers	9.0
SMR	0.7
DK Import Capacity	0.9

Hydrogen Supply Capacity in 2045 (Low H_2 Import Costs)

Scenario	GW
Electrolysers	4.9
SMR	0.7
DK Import Capacity	7.0

Figure 36 – Hydrogen supply mix (2020–2045), Sensitivity 1, Low H_2 import costs

Major Role for Gas	Low H_2 Import Costs



There is a slight difference in hydrogen supply volumes in 2045 in the Major Role for Gas scenario (72 TWh) compared to the Low H_2 Import Cost sensitivity (74 TWh). This difference is due to losses in the transport of hydrogen. In the Major Role for Gas scenario, the distances travelled in the delivery of hydrogen are relatively limited; at most, from one region to another (e.g., hydrogen produced in SE2 is transported to SE1). In comparison, in the sensitivity scenario, delivery distances are much longer; for example, most of the hydrogen demand in SE3 travels from DK.

7.2.2 Sensitivity 2: Low H_2 infrastructure costs

Sensitivity drivers

This sensitivity Investigates the impact of lower costs of hydrogen transmission infrastructure. The cost of hydrogen infrastructure consists of several network design considerations – such as pipeline diameter, pipeline length, operating pressure, flow capacity and compressor capacity. Additionally, the costs of building out new pipeline can vary significantly based on the type of terrain and other geographical characteristics. The key input assumptions used to define the cost of hydrogen infrastructure along with the resulting all-in infrastructure costs used in this sensitivity scenario and the baseline case, are presented below.

Overall, this sensitivity scenario assumes the cost of hydrogen infrastructure (pipelines and compressors) is 56% lower than in the baseline, decreasing from €540 down to €236/MW-km. Baseline costs represent the cost of 36-inch pipelines (4.7 GW), while the low case represents the cost of 48-inch pipelines (13 GW).

Table 4 – Hydrogen infrastructure input assumptions[19]

Component	Unit	Baseline (36-inch)	Low Case (48-inch)
Pipeline – New	M€/km$_{Pipeline}$	2.2	2.8
Compressor station – New	M€/km$_{Pipeline}$	0.32	0.62
LHV	GW	4.7	13

Table 5 – Hydrogen infrastructure cost results

Component	Unit	Baseline	Low Case
Pipeline	€/MW-km$_{Pipeline}$	468	192
Compressor	€/MW-km$_{Pipeline}$	68	44
Total	**€/MW-km$_{Pipeline}$**	**536**	**236**
Cost Difference	% vs Baseline	-	(56%)

Impact on gas infrastructure development

The impact from low hydrogen infrastructure costs is only a slight expansion of interconnection capacities across each of the connections along the entire DK-S1 corridor. While the change on hydrogen infrastructure costs was significant – nearly a 40% reduction – the impact on infrastructure is not as material. This shows that the costs of hydrogen infrastructure only have a second-order impact on the development of infrastructure.

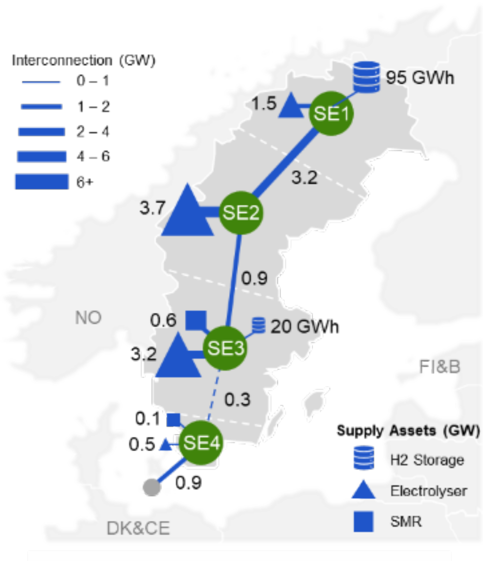
The most material increase in interconnection capacity occurs between SE2 and SE1, allowing for more hydrogen production in SE2 to be delivered northbound to SE1. The SE2-SE1 interconnection increases from 3.2 to 3.6 GW. In parallel, this leads to the buildout of additional electrolyser capacity in SE2, increasing from 3.7 GW_{H2}, in the Major Role for Gas scenario, to 3.9 GW_{H2}. Finally, this also leads to a lesser need for hydrogen storage capacity in SE1, which decreases from 95 GWh to 55 GWh.

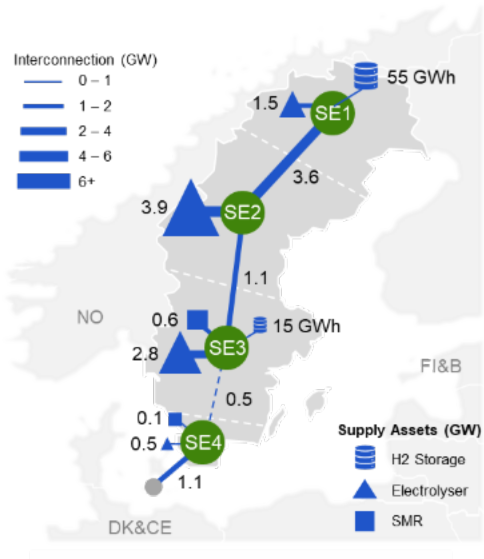
The SE2-SE3 interconnection capacity also expands, allowing for increased hydrogen supply to also flow southbound to SE3. This, in turn, leads to less electrolyser capacity being built in SE3, decreasing from 3.2 GW_{H2} down to 2.8 GW_{H2}.

[19] Extending the European Hydrogen Backbone, 2021, Table 3. Available from: https://gasforclimate2050.eu/publications/

Figure 37 – Hydrogen infrastructure in 2045, Sensitivity 2, Low H_2 infrastructure costs

Major Role for Gas	Low H_2 Infrastructure Costs





Hydrogen Supply Capacity in 2045

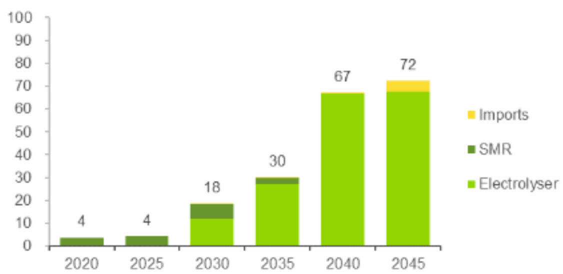
Scenario	GW
Electrolysers	9.0
SMR	0.7
DK Import Capacity	0.9

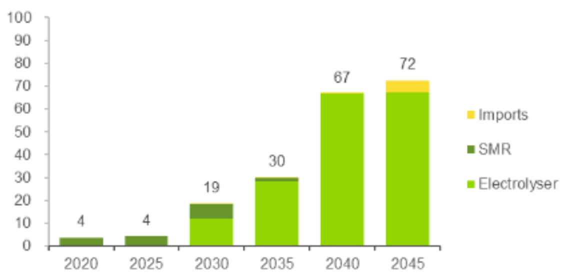
Hydrogen Supply Capacity in 2045

Scenario	GW
Electrolysers	8.8
SMR	0.7
DK Import Capacity	1.1

Figure 38 – Hydrogen supply mix (2020–2045), Sensitivity 2, Low H_2 infrastructure costs

Major Role for Gas	Low H_2 Infrastructure Costs





7.2.3 Sensitivity 3: Low electrolyser costs

Sensitivity drivers

This sensitivity Investigates the impact of lower electrolyser costs on the development of hydrogen transmission infrastructure. This sensitivity scenario takes a more aggressive outlook on future developments of electrolysers by adopting lower cost assumptions and higher efficiencies. In this sensitivity, electrolyser CAPEX drops from €325 to €185/MW_{Elec} in 2040-2045, while efficiencies improve from 72 to 77% - also for electrolyser installed in 2040-2045.

Table 6 – Comparison of 2040-2045 electrolyser CAPEX and efficiency[20]

Component	Unit	Baseline	Sensitivity
CAPEX	€000/MW	325	185
Efficiency	'%	72%	77%

Impact on gas infrastructure development

The impact from low electrolyser costs is an increase in the buildout of electrolyser capacity across most regions, which, in turn, leads to a lesser need for interconnection capacity across some regions.

The most drastic impact is on the capacity of electrolysers installed in SE2 and SE3. With lower costs and higher efficiencies, electrolyser capacity in SE2 increases significantly from 3.7 to 5.5 GW_{H2}. The increase in electrolysers installed in SE2 lead to a slight increase in the SE2-SE1 interconnection, allowing for increased transport of hydrogen from SE2 northbound to SE1.

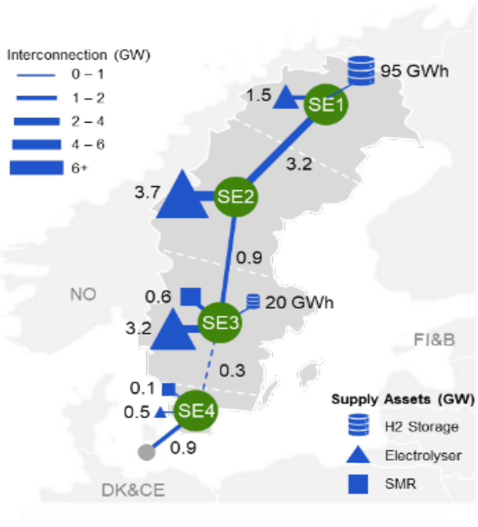
Electrolyser capacity in SE3 and SE4 also increase. In SE3, electrolysers increase from 3.2 to 3.9 GW_{H2}, while in SE4 electrolysers increase from 0.5 to 1.0 GW_{H2}. These increases in on-site placement of electrolysers decreases the need for interconnection infrastructure across regions. Interconnection capacities across DK-SE4 and SE4-SE3 both decrease. Electrolyser capacity in SE1 is unchanged. This is likely a result of the significant buildout observed in SE2, which diminishes the need for additional on-site electrolysers in SE1.

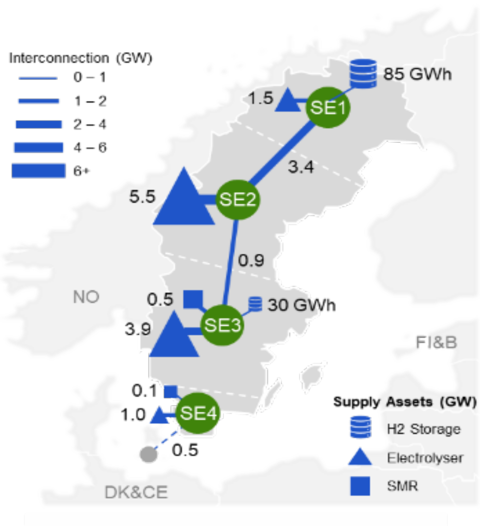
Hydrogen storage volumes in SE1 and SE3 both see changes in capacity. Storage capacity in SE1 decreases slightly from 95 to 85 GWh, driven by the oversizing of electrolysers in SE2, which are largely used to supply hydrogen demand in SE1. In contrast, storage capacity in SE3 increases from 20 to 30 GWh. This increase in storage capacity happens as the previously available interconnection with SE4 – and in-turn, the availability of hydrogen imports from DK – disappears.

[20] Lower electrolysers costs are based on: (1) BNEF, Hydrogen Project Valuation (H_2Val) Model; (2) Agora & AFRY, No-regret hydrogen; and (3) Florence School of Regulation, Clean Hydrogen Costs in 2030 and 2050.

Figure 39 – Hydrogen infrastructure in 2045, Sensitivity 3, Extended nuclear lifetime

Major Role for Gas	Low Electrolyser Costs





Hydrogen Supply Capacity in 2045

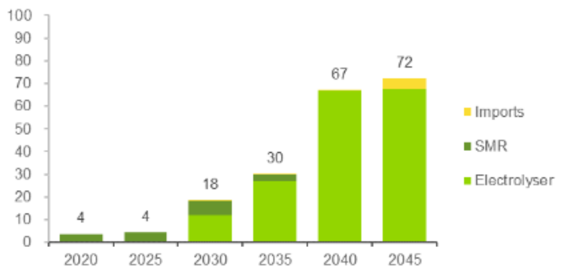
Scenario	GW
Electrolysers	9.0
SMR	0.7
DK Import Capacity	0.9

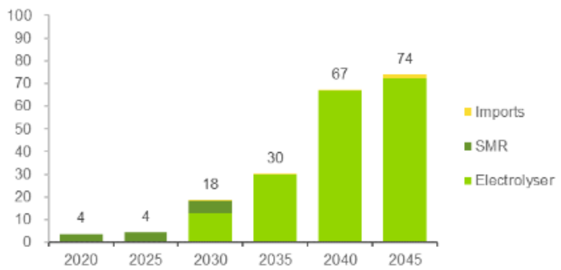
Hydrogen Supply Capacity in 2045

Scenario	GW
Electrolysers	12.0
SMR	0.6
DK Import Capacity	0.5

Figure 40 – Hydrogen supply mix (2020–2045), Sensitivity 3, Extended nuclear lifetime

Major Role for Gas	Low Electrolyser Costs





7.2.4 Sensitivity 4: Extended nuclear lifetime

Sensitivity drivers

This sensitivity investigates the impact from expanding the lifetime of the nuclear fleet. Our baseline assumption is that the 7.7 GW nuclear fleet, composed of reactors at Forsmark, Oskarshamn and Ringhals, is fully operational until 2035. Then from 2035 to 2045, all reactors are decommissioned such that by 2045, all nuclear units are offline. This sensitivity assumes the life of all nuclear reactors extends beyond 60 years such that the entire nuclear fleet remains online past 2045. This comparison is summarised by the nuclear decommissioning schedule presented below.

Table 7 – Nuclear decommissiong schedule (baseline vs. sensitivities)

Scenario	Region	2020	2025	2030	2035	2040	2045
Baseline (Major Role for Gas)	SE3	0	0	0	0	900	6815
Extended Lifetime	SE3	0	0	0	0	0	0

Impact on gas infrastructure development

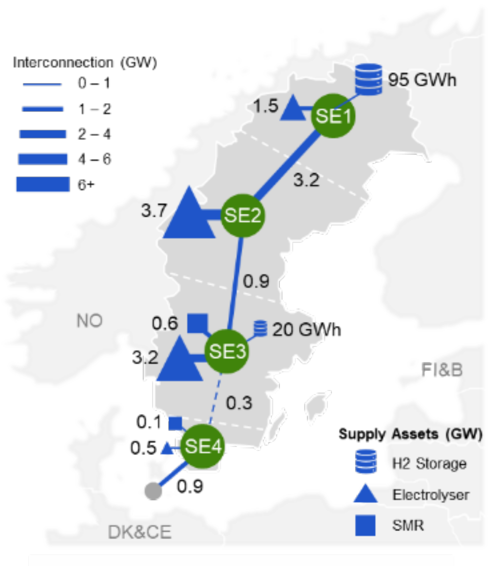
The impact from extending the operation of the nuclear fleet on the development of hydrogen infrastructure is significant. With the nuclear fleet remaining operational past 2045, there is a major increase in the availability of electricity in SE3. This leads to a geographical shift in the distribution of electrolyser capacity across SE3 and SE2, as well as in SE1. The increase availability of electricity supply in SE3 drives the buildout of additional electrolyser capacity, increasing from 3.2 GW_{H2} in the Major Role for Gas scenario, to 3.5 GW_{H2}. With this increase of on-site electrolysers, SE3 becomes less reliant on hydrogen production from SE2, which in-turn decreases the need for electrolyser capacity in SE2, decreasing from 3.7 GW_{H2} in the Major Role for Gas scenario down to 3.4 GW_{H2}. This also leads to a second-order impact on electrolyser capacity installed in SE1, which decreases from 1.5 to 1.1 GW_{H2}.

This geographic redistribution of electrolysers and changing flows of hydrogen delivery also has repercussions on the development of interconnection across the DK-SE2 corridor. With SE3 becoming less supply-dependent on SE2, the SE3-SE2 interconnection capacity decreases from 0.9 to 0.2 GW. Interconnection capacities across DK-SE4 and SE4-SE3 also become visibly weaker.

There is a very limited impact on the mix of domestic hydrogen supply vs. hydrogen imports. Dependence on imports decreases from 3% down to 1%.

Figure 41 – Hydrogen infrastructure in 2045, Sensitivity 4, Extended nuclear lifetime

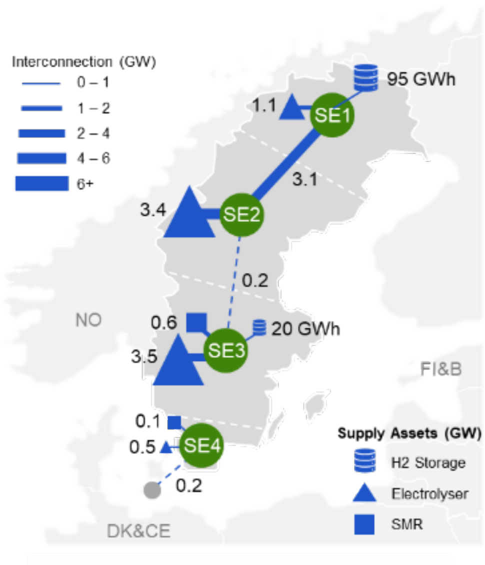
Major Role for Gas



Hydrogen Supply Capacity in 2045

Scenario	GW
Electrolysers	9.0
SMR	0.7
DK Import Capacity	0.9

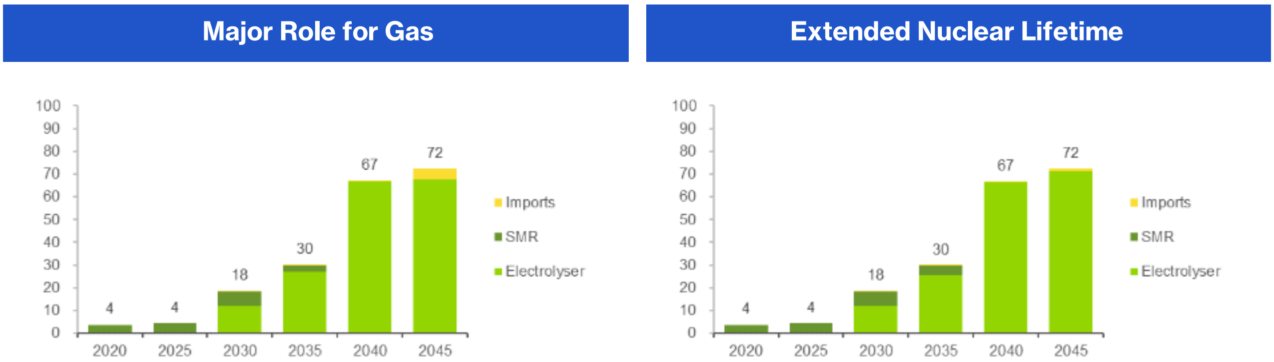
Extended Nuclear Lifetime



Hydrogen Supply Capacity in 2045

Scenario	GW
Electrolysers	8.5
SMR	0.7
DK Import Capacity	0.2

Figure 42 – Hydrogen supply mix (2020–2045), Sensitivity 4, Extended nuclear lifetime



7.2.5 Sensitivity 5: High electricity and H_2 demand

Sensitivity drivers

This sensitivity investigates the impact of a high electricity and hydrogen demand scenario on the development of gas infrastructure. This sensitivity focuses on three drivers of electricity and hydrogen demand; two of which are relatively high-profile sectors of future potential demand.

- **Data Centres:** This high demand scenario assumes the scale up of data centres in Sweden leads to 15 TWh of annual electricity demand by 2045. This is based on an aggressive assumption of 10% growth per year applied to current levels of electricity demand, which the Swedish Energy Agency estimates at approximately 1 TWh of electricity demand[21]. Compared to other growth projections for data centres, this 10% growth rate represents a more aggressive scenario[22].
- **Steel & Iron-Ore Mining:** This high demand scenario assumes 90 TWh of annual electricity from the steel and iron-ore mining sector by 2045. Compared to the Major Role for Gas scenario, this represents a 35 TWh increase. The Major Role for Gas scenario adopts LKAB's projection of 55 TWh of electricity demand at full adoption of HDRI. This 35 TWh increase assumes iron ore production levels increase at an annual growth rate of 2% per year. This growth assumption represents a more aggressive growth projection than future global projections for the metal mining sector[23]. For comparison, LKAB's projection of 55 TWh is based on future iron-ore production levels in line with historical levels of c.25-30MT/year.
- **Other demand:** The third driver of electricity demand refers to new electricity demand from the establishment of new types of industries, future electricity loads not know today, and 'conventional' electricity demand (e.g., electricity demand from appliances, electronics lighting, etc.). This high demand scenario assumes these sources of electricity demand contribute a combined 10 TWh of new demand by 2045.

[21] For comparison, the 2018 Swedish Energy Agency's High Elec Scenario modelled 8 TWh of electricity demand from data centers by 2050. This was estimated based on comparable estimates developed by third parties for Denmark (ranging from 2 to 25 TWh) and Norway (3.5 TWh).

[22] https://www.globenewswire.com/news-release/2020/09/22/2097465/0/en/Sweden-Data-Center-Market-Size-To-Reach-2-25-Billion-Growing-At-A-CAGR-Of-Over-6-During-The-Period-2020-2025.html

[23] IEA (STEPS scenario) available here: https://www.iea.org/data-and-statistics/charts/global-end-use-steel-demand-and-in-use-steel-stock-by-scenario-2000-2050 and Swedish Energy Agency (EU Reference scenario, Table 78) available here: https://energimyndigheten.a-w2m.se/Home.mvc?ResourceId=133529

Overall, total electricity demand increases by 60 TWh by 2045, equivalent to a 24% increase. The associated increase in hydrogen demand, driven by increased steel production, is 21 TWh, equivalent to a 31% increase.

The increase in hydrogen demand is assumed to be distributed proportionally to the Major Role for gas scenario, with virtually all hydrogen demand from the HDRI adoption in SE1. The increase in electricity demand driven by hydrogen demand is, in-turn, also largely in SE1. Increased electricity demand from data centers and “other demand” is distributed proportionally across all regions based on the current distribution of demand.

To cope with this significant increase in electricity demand, this sensitivity also assumes that approximately half of the existing nuclear fleet (4 GW) remains operational through 2045. This underlying sensitivity assumption is critical as it ensures sufficient baseload capacity is available to meet demand, in order to avoid unreasonable outcomes, for example, the buildout of exorbitant amounts of intermittent supply capacity.

Figure 43 – Electricity demand, Sensitivity 5, High electricity and H_2 demand

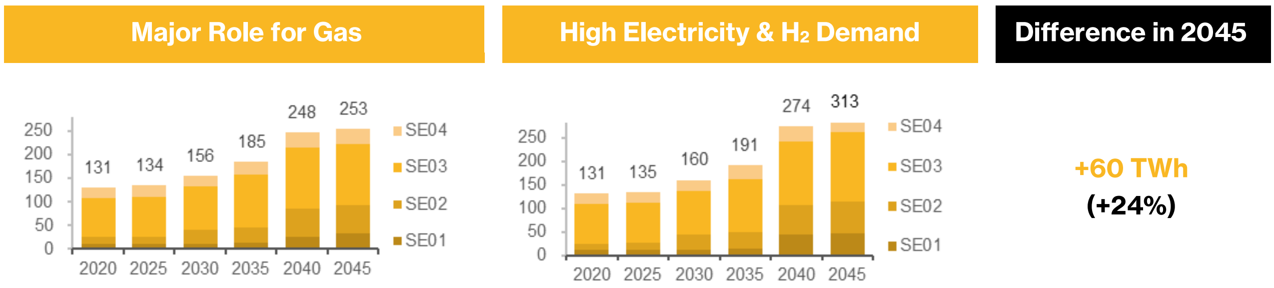
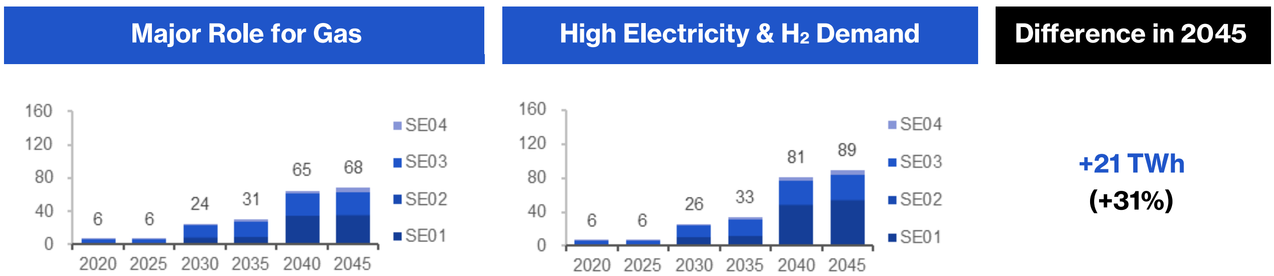


Figure 44 – Hydrogen demand, Sensitivity 5, High electricity and H_2 demand



Impact on gas infrastructure development

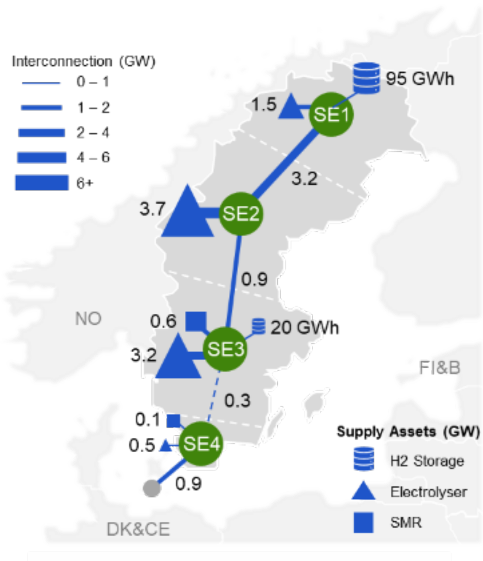
The impact on the development of infrastructure is proportional to the increase in demand. As hydrogen demand increases 31% from 66 to 89 TWh, the buildout of electrolyser capacity does as well, from 9.0 GW_{H2} to 11.8 GW_{H2}.

The development of hydrogen infrastructure north of SE2 reflects the increase in hydrogen demand in SE1. Electrolyser capacity in SE1 increases from 1.5 GW_{H2} to 2.4 GW_{H2}. Capacity of the SE2-SE1 interconnection also increases, from 3.2 GW to 4.1 GW. The buildout of electrolyser in SE2 is more moderate, increasing only slightly from 3.7 GW_{H2} to 4.5 GW_{H2}.

This more moderate increase of electrolyser buildout in SE2 reflects another underlying dynamic in SE3. Approximately half of the nuclear fleet (c.4 GW) is assumed to remain online through 2045. This leads to higher availability of electricity supply in SE3, which in-turn facilitates the scale up of electrolysers, increasing from 3.2 GW_{H2} to 4.3 GW_{H2}. Increased electrolyser capacity in SE3 reduces the need for hydrogen production in SE2 to be delivered south to SE3. This decreased hydrogen dependence from SE3 on SE2, leads to the weakening of the hydrogen interconnection between SE2 and SE3, decreasing from 0.9 GW to 0.1 GW.

Figure 45 – Hydrogen infrastructure in 2045, Sensitivity 5, High electricity and H_2 demand

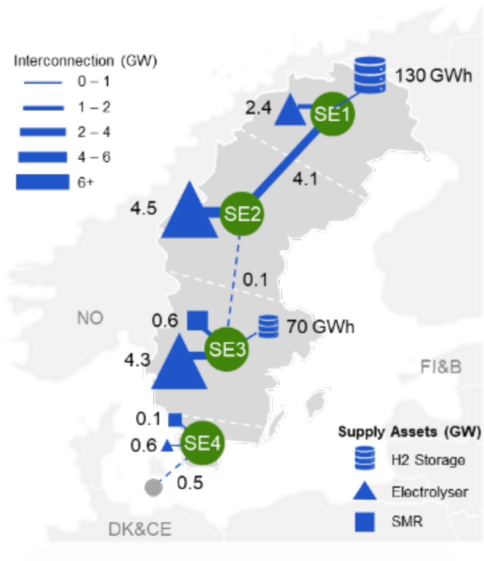
Major Role for Gas



Hydrogen Supply Capacity in 2045

Scenario	GW
Electrolysers	9.0
SMR	0.7
DK Import Capacity	0.9

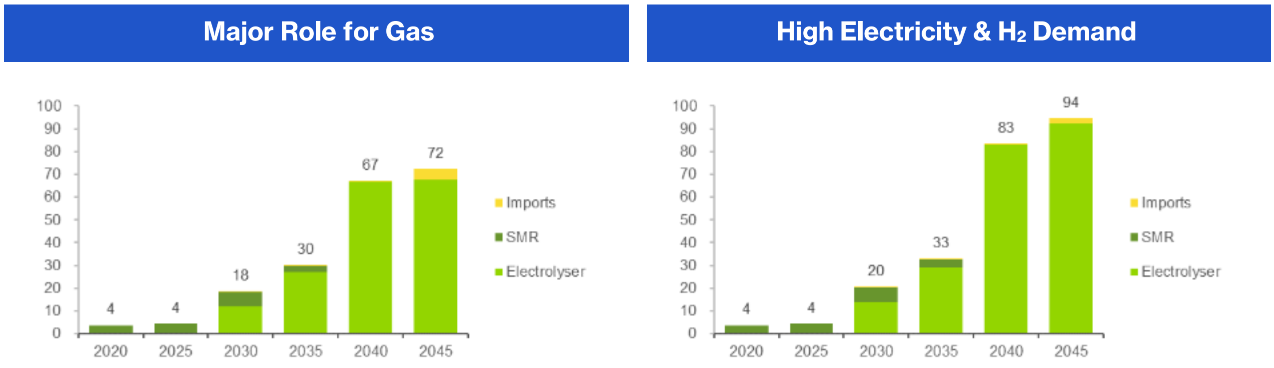
High Electricity & H_2 Demand



Hydrogen Supply Capacity in 2045

Scenario	GW
Electrolysers	11.8
SMR	0.7
DK Import Capacity	0.5

Figure 46 – Hydrogen supply mix (2020–2045), Sensitivity 5, High electricity and H_2 demand



7.3 Sweden as a hydrogen hub

This study did not set out to explore all possible outcomes for the Swedish energy system. One of these outcomes is the potential for Sweden to act as a hydrogen exporter to neighbouring countries. This potential was not explored because our approach focused on quantifying hydrogen across Swedish regions, rather than in neighbouring regions. As a result, our findings do not explicitly address whether Swedish hydrogen supply capacity and infrastructure could potentially supply and transport hydrogen to other regions. Nevertheless, the findings of this study can provide insights on how some of these scenarios could unfold. Two hypothetical scenarios are of most interest:

- **Sweden as a Hydrogen Exporter:** Could Sweden play a role as an exporter of hydrogen to mainland Europe via Denmark?
- **Hydrogen Interconnection with Finland:** Could a hydrogen interconnection develop and connect Sweden and Finland to the north?

While these two scenarios are explored in isolation, they are not mutually exclusive and could unfold in parallel – with Sweden acting as a hydrogen exporter to mainland Europe via Denmark and to Finland via an SE1 interconnection in the north.

Sweden as a Hydrogen Exporter

Relevance of hypothetical scenario

- The role of Sweden, and other Nordic countries, as a "hydrogen export hub" supplying demand centers in Central/Western Europe has received some recent traction.
- The low cost of electricity in northern Sweden, for example, has the potential to position Sweden as a cost-competitive source of hydrogen supply. While Swedish hydrogen may not be able to compete with green hydrogen production based on solar PV in Spain and North Africa, it may be competitive with hydrogen supply from the UK and the North Sea.

Insights from this study

- Our analysis shows that nearly all hydrogen demand in Sweden will be supplied by domestic green hydrogen production. Much of this hydrogen supply capacity will be concentrated in the north of the country.
- As most of this demand will be supplied via domestic hydrogen production rather than hydrogen imports via Denmark, this demonstrates that hydrogen production in Sweden is cost-competitive with other regions. This suggest that Swedish hydrogen supply capacity could potentially scale further and be exported to mainland Europe via Denmark.
- Further, Sweden regularly exports over 10 TWh/year of electricity to neighboring regions. In recent years, exports have reached highs of 20 to 25 TWh/year. Rather than continuing to export electricity, this surplus of electricity supply could potentially be used to produce hydrogen in Sweden. This hydrogen would in turn be exported to mainland Europe. This vision of Sweden as a hydrogen supply export would support the development of a full national hydrogen backbone.

Hydrogen Interconnection with Finland

Relevance of hypothetical scenario

- Roughly half of hydrogen demand in Sweden is located in the north of country, in SE1, where a steel and mining cluster of demand will develop.
- The situation in Finland is not much different, with a large industrial cluster also located in the north of the country.
- With significant future hydrogen demand concentrated in the north of both countries, this has sparked interest on whether a potential hydrogen interconnection between both countries could develop.

Insights from this study

- Our analysis shows that more than half of Swedish hydrogen supply capacity will likely be located in SE2, where electricity supply capacity is abundant. Additional hydrogen supply capacity will be located on-site, in each region, including some in SE1. Between hydrogen supply capacity in SE2 and SE1, nearly 75% of Sweden's total capacity is located in the north.
- While this supply capacity is sized to only meet Swedish hydrogen demand, should additional hydrogen demand materialise – potentially from Finland – additional electrolyser capacity would seamlessly be expanded. This in turn would lead to the development of an interconnection between SE1 and northern Finland and strengthening of the SE2-SE1 corridor. Increased interconnection capacity from SE2 would allow to transport larger hydrogen volumes, first into SE1, and then into Finland.
- The *High Electricity & H_2 Demand* sensitivity already demonstrated that additional hydrogen demand in the north would simply lead to additional electrolyser capacity.
- Availability of electricity supply in northern Finland is also highly relevant. An abundance of electricity supply would result in hydrogen being produced directly in Finland to serve demand in the north, potentially even transporting hydrogen to serve demand in Sweden.

Chapter 8

Summary of Key Pathway Insights

This analysis set out to explore the role of gas supply and gas infrastructure in the Swedish energy system up to 2045. To do this, our approach modelled the development of electricity, hydrogen and methane supply capacity, and associated interconnection infrastructure, for an integrated energy system made of Swedish and neighbouring regions, based on several demand scenarios.

For most of this report, we adopted the Major Role for Gas scenario as the central scenario for analysis. To stress test our findings, we then also evaluated the role and development of gas infrastructure under several alternative scenario hypothesis. First, we adopted a more conservative vision on the role of hydrogen and biomethane in the decarbonisation of the different demand sectors – using the Limited Role for Gas scenario. We then assessed the development of gas infrastructure based on several uncertainties – with five sensitivity scenarios – and finally, we explored two hypothetical scenarios investigating the role of Sweden as a potential exporter of hydrogen to neighbouring regions.

Across all these scenarios and sensitivities, several common themes and insights emerged:

Decarbonisation of energy demand

- **Hydrogen and biomethane will play a key role in the decarbonisation of industry and transport.** All major Swedish energy stakeholders expect to see a future in which hydrogen and biomethane play a key in decarbonising energy demand. Our stakeholder consultation process – gathering input from key demand sectors like steel, mining, heavy road and shipping – reinforced this vision of the future. This vision is reflected in the similarities across our two demand scenarios: for example, with the adoption of hydrogen-based direct reduction in steelmaking, or the role of biomethane and hydrogen in heavy road transport and shipping.
- **Hydrogen and biomethane adoption will lead to regional demand clusters.** The adoption of hydrogen and biomethane across industry and transport will lead to the development of regional clusters of gas demand across Sweden. In the north of country, the decarbonisation of the steel sector will lead to the development of a large hydrogen cluster in SE1. Since many related pilot projects are already underway in Norbotten, all our scenarios and sensitivities assume this hydrogen cluster will develop in the future. Transport hubs and industries around major cities will also lead to hydrogen clusters developing in SE3 and SE4. From a biomethane perspective, the adoption of biomethane in heavy road transport and shipping also leads to the development of transport clusters in SE3 and SE4. The location of these gas demand cluster across Sweden will have an impact on the buildout of hydrogen and biomethane supply capacity and interconnection infrastructure.

Electricity supply capacity and infrastructure

- **Electricity supply capacity is forecasted to increase significantly to serve demand.** All our demand scenarios forecast a significant increase in electricity demand. The Major Role for Gas scenario forecasts an almost doubling in demand from 130 to 253 TWh, while the Limited Role for Gas scenario forecasts a slightly more moderate increase to 241 TWh. In both cases, much of this increase in electricity demand is associated with demand for hydrogen production. Whether one scenario or the other, this increase in electricity demand will require a significant scale up in electricity supply capacity. In the Major Role for Gas scenario, generation capacity increases from 40 GW today to 86 GW by 2045. Most of the increase in capacity is associated with onshore and offshore wind developments. Combined, wind capacity increases from 9 GW today to 53 GW by 2045, resulting in wind electricity production increasing from 25 TWh today to 180 TWh by 2045.
- **A strong buildout of electricity interconnection infrastructure will be required.** In line with the buildout of electricity supply capacity, strengthening of electricity interconnection capacity between Swedish regions, as well as between Swedish and neighboring regions will also be required. This buildout in infrastructure will occur largely along the SE2-SE4 corridor, delivering electricity from SE2 – a region with high electricity generation capacity – to demand centers in the south in SE3 and SE4. Significant interconnection infrastructure is also required to accommodate increasing shares of offshore wind capacity, as it scales rapidly from 2030 to 2045 in SE4 and SE3.
- Our analysis does not find a major role for hydrogen in energy supply or flexibility. Our findings do not show a role for hydrogen in the power sector. This finding is not unexpected given the context of the Swedish power system, being at the centre of a highly interconnected Nordic electricity grid and with large availability of hydro reservoir. Combined, these features give the Swedish power grid a high degree of flexibility[24].

Hydrogen supply capacity and infrastructure

- **A regional hydrogen backbone will emerge along the SE3-SE1 corridor.** In all scenarios and sensitivities, our analysis shows the build out of hydrogen interconnection infrastructure between SE1 and SE3. This backbone supply hydrogen to demand clusters at both ends; in SE1, where the steel and mining industry clusters will develop, and in SE3, where smaller industry and transport hubs develop in and around major cities.
- **Electrolyser capacity will scale rapidly from 2030 to 2045.** All scenarios and sensitivities show significant growth in electrolyser capacity by 2045 – ranging from as low as 4.9 GW_{H2} in the Limited Role for Gas scenario to as high as 12 GW_{H2} in one of the sensitivity scenarios analysed, the Low Electrolyser Costs sensitivity. Most growth in electrolyser capacity is forecasted from 2035 to 2040, when most of the decarbonisation of the steel sector is expected.
- **Hydrogen infrastructure complements the electricity grid.** All scenarios and sensitivities consistently show a significant share of electrolyser capacity will be installed in SE2. The siting of electrolysers in SE2 is a strategic decision. Electrolysers are sited strategically in SE2 to utilise an oversupply of electricity generation and to release bottlenecks along the SE2-SE3 corridor. With the buildout of electrolysers in SE2, SE2 is positioned as a hydrogen production hub serving demand for hydrogen in SE1 and SE3. The siting of electrolysers in SE2 illustrates how hydrogen and electricity networks can play complementary roles.

[24] This finding may be driven by the temporal granularity of our modelling methodology. Our analysis uses five (5) representative days to model the hourly dispatch of electricity supply – four seasonal days and a winter peak day. One of the challenges of this approach is that with extreme weather events becoming more frequent, representative days become less useful. In contrast, an analysis considering all 8760 hours of the year would better capture extreme weather events and their impact on the power system, potentially identifying a role for hydrogen in power flexibility.

- **Sweden has the potential to act as a hydrogen exporter to neighbouring regions.** While this report did not explicitly explore the role of Sweden as an exporter of hydrogen, our analysis shows that nearly all hydrogen demand in Sweden will be supplied by domestic hydrogen production. This demonstrates that hydrogen production in Sweden is cost-competitive with hydrogen from neighbouring regions and that Swedish hydrogen could potentially be exported to mainland Europe via Denmark (DK), or Finland via SE1.
- Hydrogen production via SMR will continue to play a role. This study shows that, while limited, new SMR capacity will continue to be deployed until 2030. This finding is consistent across all scenarios and sensitivities. Post-2030, new investments will steer predominantly towards green hydrogen via electrolysis. Nonetheless, existing already paid-for blue hydrogen installations will continue to be operational in the future with CCS retrofits. Hydrogen production via SMR+CCS has the potential to become a source of negative emissions if the methane used in the production process is biomethane rather than natural gas. This is relevant given the ambition of Nordion Energi to develop a 100% renewable methane grid.

Methane supply capacity and infrastructure

- **Future expansion of the existing methane interconnection from Denmark to SE3 will not be required.** Neither the Major Role for Gas scenario nor the Limited Role for Gas scenario show the need for additional methane interconnection capacity from DK. While methane volumes flowing through the grid will continue to ramp up until 2030, expansion of the existing interconnection will not be required because the grid still has sufficient headroom available for future growth. Further, our analysis shows that beyond 2030, domestic capacity of anaerobic digestion (AD) and biomass gasification will ramp up.
- **Domestic methane production will scale up over time.** Our scenarios show that AD supply capacity will drastically ramp up – largely in SE3 – beginning in 2030. Over time, methane supply from AD will increasingly displace volumes of methane imports from DK. By 2045, methane volumes from domestic supply will be greater than import volumes from DK. In the Major Role for Gas scenario, the ramp up in AD capacity will be complemented by a ramp up in biomass gasification capacity.

Chapter 9

Decarbonisation Pathways Roadmap

This study has developed a clear view on the magnitude of infrastructure development required to scale up electricity and gas infrastructure in Sweden from today to 2045. The magnitude of the investment required to finance this transformation is unprecedented and will undoubtedly be one of Sweden's largest infrastructure undertakings of all time, if not the largest. The scale up of electricity, hydrogen and biomethane supply capacity and infrastructure will also drastically transform the Swedish energy system as we know it.

At the core of this transformation, and with a critical responsibility for enabling and facilitating the decarbonisation of end-users, will be the electricity and gas transmission and distribution network companies. They will ultimately be responsible for ensuring renewable and low-carbon energy supply is available to end-users where they need, when they need and how they need it – whether electricity or gas.

Nevertheless, to successfully manage this transformation will require all Swedish energy stakeholders to align on a common vision for decarbonising the Swedish energy system. As such, there is an urgent need to ensure the right market conditions, and the right regulatory and operating environment are put in place, at the right time. The ultimate objective will be to ensure that the underlying energy and climate policies, and the regulatory framework will create attractive commercial and financial conditions for energy infrastructure companies to finance the transformation of the energy system.

In this context, this section develops a roadmap that identify a list of near-term, strategic actions and initiatives required to set the Swedish energy system on a net-zero trajectory by 2045. The actions identified in this roadmap are relevant for all scenarios and sensitivities investigated in previous sections.

This roadmap aims to answer the following questions:

- **What** actions and decisions are required to scale-up electricity and gas infrastructure?
- **When** should these actions and decisions be undertaken?
- **Who** should be responsible to implement these actions and decisions, and what other energy stakeholders should provide support?

This section begins with Section 8.1 exploring barriers – real and perceived – to the scale-up of electricity, hydrogen and biomethane supply and infrastructure. Section 8.2 then presents an action-plan roadmap that aims to mitigate those barriers in order to create attractive market and regulatory conditions to investment.

To support the development of this roadmap, Energiforsk and Guidehouse conducted an extensive consultation process, collecting views from electricity and gas companies, public agencies and end-user groups on the major barriers and challenges underpinning this transformation.

Energiforsk and Guidehouse also reviewed a number of relevant, recent high-profile roadmaps developed by three major Swedish energy stakeholders. While this roadmap is wholly independent of them, its development and the list of actions proposed in this roadmap build on the extensive work already developed by these stakeholders. As such, we have chosen to reinforce a selection of the most impactful and strategic actions and initiatives proposed by them.

- **Gas Sector Roadmap for Fossil Free Competitiveness** by the Swedish Gas Association (Energigas Sverige).
- **Roadmap 2040: Wind Power, combating climate change and improving competitiveness** by the Swedish Wind Energy Association; and
- **Hydrogen: Strategy for fossil free competitiveness** by Fossil Free Sweden (Fossilfritt Sverige).

9.1 Barriers and challenges

While the decarbonisation of the energy system hinges primarily on the scale-up of energy supply technologies, many of which are not commercially available today, the underlying technologies themselves are not actually perceived as being major challenges or barriers. Rather, most Swedish energy stakeholders agree that the biggest barriers to scaling up energy supply and infrastructure are primarily a combination of institutional, regulatory, and societal barriers. Nevertheless, technical barriers, as well financial barriers, do exist and may hinder future energy infrastructure developments.

Institutional

The energy system today does not require much, if any, coordination on forecasting and planning of electricity and gas infrastructure. However, the future energy system will become increasingly integrated – across electricity and gas networks – and will require all major energy stakeholders to break down existing organisational barriers. For example, hydrogen supply forecasting will be intrinsically dependent on electricity supply. Gas planners will need to work hand in hand with electricity planners to better understand future electricity supply and limitations on available transmission capacity.

Regulatory

Regulatory processes are, by design, complex and thorough, in order to ensure energy supply and infrastructure investments are justified, fit and proper, and in the best interest of customers. This due diligence can, at times, lead to lengthy and unpredictable processes that hinder the development of infrastructure projects. The growing pipeline of energy infrastructure projects will require a more sustainable regulatory review process, and similarly a more predictable and timely permitting process. Investments in hydrogen supply and infrastructure may also face challenges if the existing regulatory framework does not evolve to acknowledge the differences in dealing with hydrogen compared to natural gas or biomethane.

Financial

While the financing of electricity generation and transmission projects is well understood, the same cannot be said about hydrogen infrastructure projects. Currently, there is no clarity on how the government and regulator may view the financing of early hydrogen infrastructure projects, the expansion of hydrogen infrastructure projects to a larger customer-base, and how – if at all – regulatory rate-base financing may have to evolve. Large-scale biomethane projects (AD and bioSNG) also face financing challenges, and in the case of bioSNG, to some degree, driven by the past experience with GoBiGas. Domestic biomethane projects are also challenged by not playing on the same level playing field as biomethane supply from neighbouring jurisdictions. From an end-user perspective, the financing challenge is not much different. How will the government support industry and others in the transition to fossil-free hydrogen? Will decarbonisation projects be self-financed and justified based on fluctuating ETS prices?

Technical

Although gas companies have extensive experience transporting and delivering natural gas and biogas, there is very limited technical expertise with hydrogen. And while hydrogen transport is not that much different than other gases, the magnitude of gas volumes transported in pipelines today (<10 TWh) pale in comparison to gas volumes being forecasted for the future.

Societal

While at a national-level – and in the court of public opinion – there is generally relatively strong acceptance for renewable energy projects, the level of support often breaks down at a local level. Not-In-my-backyard (NIMBY) sentiments remain strong and have an overpowering influence on whether large-scale energy generation and transmission projects move ahead or are shut down.

The tables below describe the major barriers to the scale up of electricity, hydrogen, and biomethane supply and related infrastructure.

Table 8 – Barriers to scaling up electricity supply and infrastructure

	Barriers & Impact on Electricity Pathways
Institutional	**1. Uncertainty of future electricity supply and existing limitations on available transmission capacity.** Future availability of electricity supply in areas of high future demand (SE1) and existing 'bottleneck' areas build uncertainty on long-term planning by industrial end-users. Existing transmission constraints in 'bottleneck' areas of the country (pockets of SE3 and SE4) can limit industry end-users from electrifying. Industries in other areas (SE1 and SE2) do not face the same challenges.
	2. No coordination and consistency in long-term forecasting of electricity and gas networks. Limited coordination, if any, exists between electricity and gas TSOs on transmission/distribution network planning and long-term demand forecasting. This lack of coordination may mean that TSOs may have conflicting views on how industry and transport will decarbonise. While this may be acceptable today, the energy system will become increasingly integrated in the future.
	3. Risk-averse decision making on infrastructure investments and lack of proactive planning. TSOs have a natural tendency to be risk-averse when it comes to making investment decisions of large-scale infrastructure projects. These projects generally have long lead times, long construction periods, and are capital intensive. This results in a network planning process that is often reactive rather than proactive, which in-turn leads to sub-optimal timing of investments and decision making.

Regulatory	**4. Complex, lengthy and unpredictable permitting processes.** Permits for large-scale power generation projects and transmission infrastructure can often take too long and be unpredictable. **5. Availability of land use for energy infrastructure is not prioritised**. Energy infrastructure projects often must *compete* with higher priority land-use purposes such as military and environmental protection. **6. Regulatory readiness to process large pipeline of electricity projects.** The Energy Markets Inspectorate processes and manages the regulatory review of all new electricity generation and transmission projects. As the pipeline of projects grows in the coming years, there are concerns that the current bandwidth will not be sufficient to efficiently manage the process leading to delays.
Societal	**7. NIMBYsm of large-scale power generation and transmission projects.** The importance of local (and regional) acceptance of large-scale generation and transmission projects is often disregarded. One of the most challenging issues faced by large-scale projects is the "veto" power held by municipalities. In the past, projects have been halted due to local pushback. Adding to this, different dynamics are at play in different regions. Traditional "wind power regions" in the North have reaped positive benefits of wind power such as employment and tax income, whereas other regions face strong opposition.

Table 9 – Barriers to scaling up hydrogen supply and infrastructure

	Barriers & Impact on Hydrogen Pathways
Regulatory	**1. Limited regulatory and institutional knowledge with hydrogen.** There is a need to ensure knowledge about hydrogen supply and infrastructure among policy and regulation decision makers. Sweden, in particular, doesn't have the same know-how and level of expertise that other "gas-heavy" EU countries have. **2. Lack of framework and market conditions.** Potential hydrogen offtakers point to the lack of EU / national frameworks and market conditions as barriers to scaling supply and demand for hydrogen. Without a view on how regulators will handle hydrogen topics, gas operators and end-users can only rely on regulatory hypotheses and strategise based on existing business models. Until EU directives and/or a national view is developed, infrastructure developers and end-users will continue to face uncertainty around hydrogen.
Institutional	**3. No coordination and consistency in long-term forecasting of electricity and gas networks.** This barrier was also identified among the list of barriers on the electricity side since this barrier involves both electricity and gas companies. **4. Lack of long-term hydrogen-related targets.** Lack of long-term hydrogen-related targets that can provide consistent guidance on long-term planning and investment decisions to all relevant players.[25]

[25] In February 2021, the Government instructed the Swedish Energy Agency to develop a national hydrogen strategy. As of June 2021, this strategy is under development and is schedule to be finalized by July 2021.

Technical	**5. Technical and operational experience with hydrogen infrastructure is limited.** Technical and operational experience with hydrogen infrastructure is limited, if any at all outside of industry. Hydrogen grid infrastructure and supply assets are limited to few industrial areas in SE3 and SE4.
	6. Limited H_2 storage potential. Sweden lacks natural geological formations for large-scale hydrogen storage hence there are limited possibilities for cost-effective storage.
Financial	**7. Unclear government perspective on financing of early hydrogen infrastructure.** There is no government position on the level of support, if any, available to support early hydrogen infrastructure. Unclear on what role government and regulator may play in enabling / facilitating those investments – e.g., whether through traditional regulated asset base (RAB) methods, or others[26].
	8. Unpredictability of EU ETS prices. While ETS prices are projected to continue rising, the underlying unpredictability of EU ETS prices does not give hydrogen offtakers the predictability of long-term future cashflows need to justify internal business decisions for hydrogen adoption.
	9. Green Gas Principle. Uncertainty on the application of the "green gas principle" to hydrogen in taxation purposes

Table 10 – Barriers to scaling up biomethane supply and infrastructure

	Barriers & Impact on Biomethane Pathways
Regulatory	**1. Regulatory / market treatment of biomethane has potential to be strengthened.** While the domestic biogas/biomethane market has received investment support (e.g., investment and production support, tax exemption, etc.), several additional market levers remain under development and consideration; for example, guarantees of origin, registers, and renewable gas certificates. In some cases, existing regulation can also be unfavorable for example, treating biomethane and natural gas as equals if produced in parallel.
Financial	**2. Large-scale biomethane production can be risky.** Large-scale biomethane production can be risky. Major financial risk in long-term investments, especially in relatively new technologies such as bioSNG. In this context, while the GoBiGas was successfully in proving the technology and operation of bioSNG plants, the industry will now have to deal with long-term perceptions of high costs.
	3. Decarbonisation costs for large end-users are unaffordable. While transport and heat customers are already largely using biomethane, large industrial end-users continue to use natural gas. Most of these large end-users do not have financial incentives to transition to low-carbon or renewable gas, and since they operate in cost-competitive international markets, they have very limited ability to pass their increased energy costs to consumers.
	4. The playing field is not leveled for domestic biomethane production. Domestic biomethane production is also challenged in comparison to market conditions in neighboring jurisdictions. In Denmark, policy instruments make biomethane supply more cost effective than Swedish biomethane. The Governmental Biogas Market Inquiry (Biogasmarknadsutredningen) identified this a key barrier to scaling up domestic biomethane. Further, the substrate market for biomethane feedstock is quite limited in Sweden, and where available, it is distant to gas demand centers. This is compared to the Danish situation, where there is large-scale substrate supply and extensive gas infrastructure.

[26] The European Commission is not expected to publish a regulatory proposal before Q4-2021. From then, it may take until 2022/2023 for an EU deal, and in-turn, Member States may not be able to develop country-specific regulations until 2024. local Then the member states get a year to transpose so that will be mid-2024. In Sweden, the first few major projects are expected to begin to be realized from 2026 onwards, which puts Sweden on a very tight timeline.

9.2 Roadmap to scale-up energy supply and infrastructure

Addressing and mitigating the barriers presented in the previous section will be fundamental in order to rapidly scale-up electricity, hydrogen and biomethane supply and infrastructure. The roadmap presented in this section is a strategic plan of actions and initiatives for all major energy stakeholders to implement in the near-term, from now and to 2025. This initial 5-year period will be crucial in ensuring the Swedish energy system is in the right trajectory to net-zero. Individually, these actions will likely only have a limited impact on policy, regulatory or market conditions. However, collectively, they have the potential to create a more systemic and immediate shift in the decarbonisation of the Swedish energy system, putting it on a net-zero trajectory by 2045.

The actions in this roadmap are categorised into six distinct themes requiring action:

1. **Supporting the Development of the Electricity System.** The strengthening of the electricity system is foundational for the development of future hydrogen infrastructure and the production of green hydrogen. Several actions by the TSO and other stakeholders can ensure the electricity system is strengthened and can support the development of a hydrogen system: identifying priority electricity transmission lines and future electricity supply capacity, identifying opportunities for proactive grid investment in anticipatory infrastructure, developing an electricity-and-gas integrated "whole of system" planning approach, among others.

2. **Setting a Clear and Decisive Decarbonisation Direction.** There is a strong need for the government and policy makers to come out with a clear direction and path forward on several key energy supply and infrastructure topics: a made-in-Sweden view on the development of EU-level hydrogen regulations, an offshore wind strategy (on the heels of the EU's offshore wind strategy), and guidance to Sweden's major energy stakeholders with regards to long-term planning of low-carbon and renewable gas supply.

3. **Supporting the Transition of End-Users to Fossil-Free Energy.** For some sectors, the cost of transitioning to low-carbon and renewable gases can be passed-through to consumers. Some other sectors are more cost-sensitive and must remain cost-competitive in international markets. There's a clear need to better understand how different sectors will finance their decarbonisation, to identify what domestic and EU-level measures can be used to support their transition; among those, understanding how a carbon border adjustment mechanism in the EU-ETS could support local industries, or the application of the "green gas principle" to hydrogen use.

4. **Developing Attractive Market Conditions for Hydrogen and Biomethane Infrastructure Investments.** The scale up of hydrogen and biomethane supply capacity and infrastructure in the future will require having the right market conditions and financial levers in place. Stakeholders across the entire gas value chain – production, transmission, distribution, and consumers – have a role to play. There's a need to better understand what market measures (e.g., contract-for-differences or otherwise) can boost future demand and supply of hydrogen.

5. **Preparing for a Future Hydrogen System.** The development of a hydrogen system will require developing a better understanding of future potential network configurations and the design of hydrogen transmission and distribution networks. There's also a need to explore in more detail the medium-term role for blue hydrogen, the potential of gas-to-power technology in the electricity system, and the hydrogen storage needs and potential of a future hydrogen system.

6. **Creating an Enabling Regulatory Environment.** Energy regulators have a fundamental function in the value chain of large-scale energy infrastructure projects. However, as the energy system evolves, so should energy regulators. Several key actions can better position the Energy Markets Inspectorate for this role: among those, establishing electricity and hydrogen regulatory sandboxes to evaluate new, large-scale infrastructure projects, assessing its readiness to cope with and process a large pipeline of future projects, and gathering stakeholder inputs on hydrogen regulation and financing measures through a consultation process.

9.2.1 Supporting the development of the electricity system

1.1 **Define strategic transmission and generation infrastructure plans.** Svenska Kraftnat should identify electricity transmission infrastructure projects that will be prioritised for reinforcement / upgrade in the next 5 to 10 years and a clear timeline for those investments. Clarity is also needed on the existing pipeline of electricity generation projects and expected dates of operation. Staying on track with strategic investment plans will provide certainty of supply to major energy end-users.

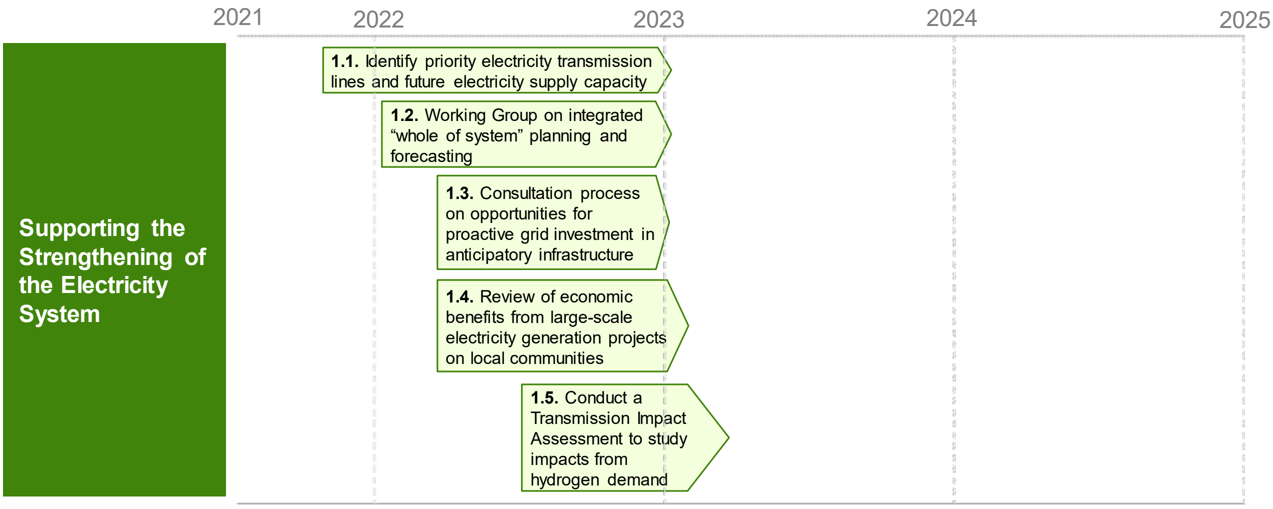
1.2 **Working Group on integrated "whole of system" planning and forecasting.** Svenska Kraftnat and Nordion Energi should create a working group tasked with creating a more holistic "whole of system" approach to long-term planning and forecasting. Both TSOs will play key roles in the design of a future integrated energy system. Demand forecasts should be developed in coordination by electricity and gas TSOs (and other relevant public agencies) and be grounded on a common set of demand growth and decarbonisation assumptions.

1.3 **Consultation process on opportunities for proactive grid investment in anticipatory infrastructure.** By adopting a "whole of system" planning approach, Svenska Kraftnat and Nordion Energi will develop business plans based on common methodology, forecasting and a common set of assumptions. This, in-turn, facilitates cross-sectoral planning and ensures investment decision making is cost-optimal from an energy system perspective, and ultimately less risk-averse. The Energy Markets Inspectorate should take stock of this and facilitate investments by TSOs on anticipatory infrastructure.

1.4 **Review of economic benefits from large-scale electricity generation projects on local communities.** The Government should review the status quo of how economic benefits flow to local communities to better align local interest with the development of infrastructure projects. Local communities have significant sway and decision-making power over large-scale electricity generation projects. This greater influence should also be reflected in the distribution of economic benefits: for example, through local taxes. If local communities are fairly compensated with a greater share of the economic benefit, they are more likely to be more accepting of large-scale projects. More specifically, the Government should make a decision on whether proceeds from property/real estate taxes associated with wind projects should remain with the Government or be transferred to the municipalities where projects are built.

1.5 **Conduct a Transmission Impact Assessment to study impacts from hydrogen demand.** Svenska Kraftnat should perform a grid impact assessment to identify future network impacts of green H_2 production on transmission capacity requirements and regional energy flows. While hydrogen demand is expected to be the largest driver of future electricity demand, electrolysers may not necessarily be sited on-site at hydrogen demand points. This study should evaluate network impact under various electrolyser "on-site" and "off-site" configurations.

Figure 47 – Action Plan to Support the Strengthening of the Electricity System



9.2.2 Setting a clear and decisive decarbonisation direction

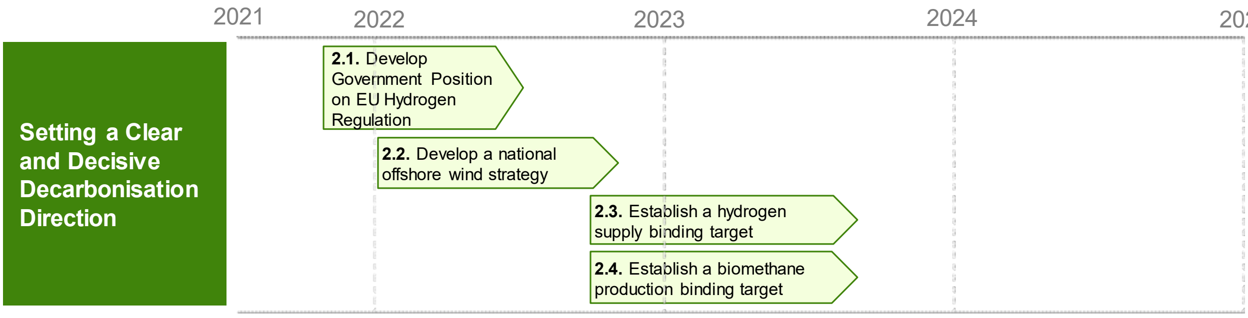
2.1 **Government Position on EU Hydrogen Regulation.** The Government should formulate a clear position on the EU hydrogen regulation, together with the various hydrogen supply chain actors, and engage in the EU debate. This regulation should clarify market rules for hydrogen production, transport and delivery, consumption, and related issues.

2.2 **Develop a national offshore wind strategy.** In line with the European Commission's Nov-2020 guidance on offshore wind development, the Government should develop a national offshore wind strategy. Setting a soft planning goal to provide a clear, long-term planning baseline for all relevant agencies in their internal planning activities – Svenska Kraftnat, the Energy Markets Inspectorate, the Swedish Energy Agency and the Swedish Environmental Protection Agency. For example, establishing a planning goal of 120 TWh of wind energy by 2040 – as outlined in the Swedish Wind Energy Association's roadmap – would give Svenska Kraftnat clear direction to plan offshore transmission needs, identify bottlenecks, and develop a grid-connection strategy

2.3 **Establish hydrogen supply planning targets.** The Government should define medium-term (2030) and long-term (2045) planning targets for green hydrogen generation capacity. A planning target is not intended to be legally binding but rather a strategic objective that can provide clarity for electricity and gas system planning and regulatory planning – much like the strategic ambitions set by other countries like France (6.5GW) and Spain (4GW), and the European Commission (40GW). The Swedish Energy Agency is currently developing a national hydrogen and electrofuel strategy (scheduled to be finalised by November 2021) which can provide insights in defining a target.

2.4 **Establish a biomethane production binding target.** The Government should define a medium-term (2030) biomethane production binding target as proposed by the Governmental Biogas Market Inquiry (Biogasmarknadsutredningen). Adopting a binding target will provide a clear long-term planning horizon and investment certainty for biogas market players, investors and for regulatory planning. This binding target would resemble the nature of targets defined under the EU's Renewable Energy Directive (RED II) setting an obligation for fuel suppliers to meet this target. With a binding target, Sweden could employ adequate market measures to ensure that a production target is met, as well as define intermediate targets and review periods to ensure Sweden remains on track.

Figure 48 – Action Plan to Set a Clear and Decisive Decarbonisation Direction



9.2.3 Supporting the transition of end-users to fossil-free energy

3.1 **Guidance on zero-emissions factor for co-distributed biogas.** The Swedish Environmental Protection Agency (EPA) should clarify the application of the zero-emissions factor defined by the EU ETS for co-distributed biogas in a Swedish context. Currently, when biogas is distributed and consumed directly from a biogas producer, it is assigned a zero emissions factor in the EU ETS. However, according to EU ETS, when biogas is blended with natural gas and distributed to consumers via the gas grid, biogas is treated as fossil gas. A Nov-2020 revision of the Monitoring and Reporting Regulation (MRR) will, from Jan-2022, also assign a zero emissions factor to co-distributed biogas from gas grids based on purchase records. The EPA should establish clear guidelines that clarify the application of the MRR-rule in Sweden encouraging large end-users in the EU ETS to switch to biogas to reduce their ETS costs.

3.2 **Support Carbon Border Adjustment Mechanism in the EU-ETS.** The Government should push for a Carbon Border Adjustment Mechanism (CBAM) as part of the EU-ETS. The CBAM would place a charge on the carbon content of emissions-intensive goods and products imported into the EU. This is particularly important for the iron and steel sector, as it would aim to level the playing field.

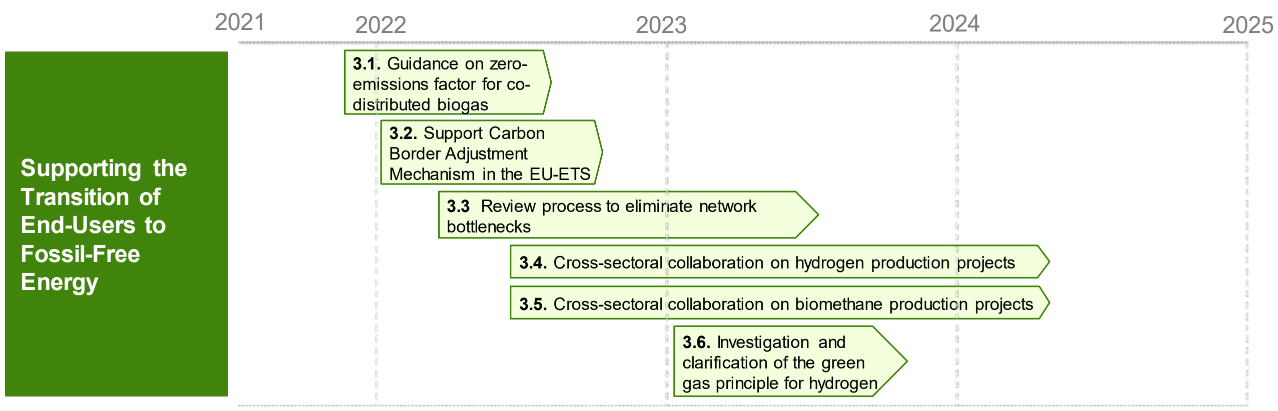
3.3 **Review process to eliminate network bottlenecks.** Svenska Kraftnät should launch review process to eliminate network bottlenecks preventing industry from electrifying operations. As identified in Fossilfritt Sverige's hydrogen roadmap, rapid measures should be taken to eliminate existing network capacity bottlenecks and other network obstacles in the way of the electrification of industry.

3.4 **Cross-sectoral collaboration on hydrogen production projects.** Nordion Energi, Svenska Kraftnät, and Gas & Electricity DSOs should establish a working group to identify and work on cross-industry collaboration opportunities between energy infrastructure developers (as future potential hydrogen suppliers) and future hydrogen offtakers. The steel and mining industry cluster in Norrbotten, perhaps of the earliest and largest hydrogen clusters globally, provides a great opportunity to explore and develop operational, commercial, and regulatory learnings. For example, on the operation of grid- and renewables-sited electrolysers, on-site vs. off-site conversion into hydrogen, hydrogen infrastructure financing approaches, among others. The Swedish Energy Agency and other energy authorities and stakeholders may also be invited to participate to provide input and expert advice on relevant topics.

3.5 **Cross-sectoral collaboration on biomethane production projects.** The Swedish Energy Agency, Nordion Energi and the Gas DSOs should identify cross-industry collaboration opportunities between biomethane suppliers and large biomethane offtakers to investigate and prove the commercial feasibility of large-scale bioSNG projects. Large-scale adoption and commercialization of bioSNG production will likely only develop at significant scale from 2030 and may require new business models/ policies/long-term offtaker contracts to support extensive deployment.

3.6 **Investigation and clarification of the green gas principle for hydrogen.** The Government should clarify the application of the green gas principle to green hydrogen. To ensure that the "green" value of renewable hydrogen follows from producer to consumer, the green principle should also be applied to hydrogen, just as it is applied to biogas. In the biogas context, the green gas principle means that the share of biogas out of the total gas volumes purchased through the gas grid is based on purchase agreements and the mass-balance principle. This treatment is necessary in order to be able to buy and sell renewable hydrogen when it is blended with fossil hydrogen, as well as to benefit from future support schemes or tax exemptions encouraging the use of renewable hydrogen.

Figure 49 – Action Plan to Support the Transition of End-Users to Fossil-Free Energy



9.2.4 Developing attractive market conditions for investments in hydrogen and biomethane infrastructure

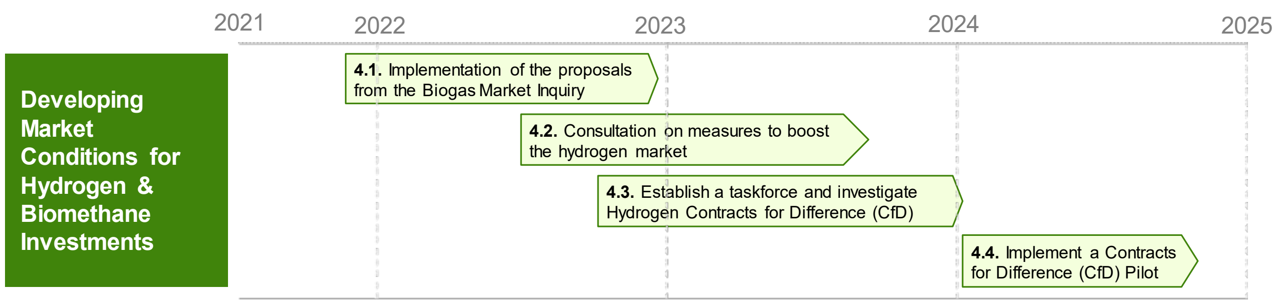
4.1 **Implementation of the proposals from the Biogas Market Inquiry**. The Government should establish a clear timeline to implement the proposals from the 2019 Biogas Market Inquiry to introduce a set of financial instruments to boost the production of biogas/biomethane in Sweden. The investigation pointed out the importance of leveling the playing field for Swedish market players in relation to their Danish counterparts. To do this, the Inquiry proposed the introduction of production support premiums along with the retention of already-existing tax exemptions.

4.2 **Consultation on measures to boost the hydrogen market.** The Swedish Energy Agency should launch a consultation process with the aim of identifying market measures that can stimulate hydrogen demand and supply (e.g., guarantee of origin, traceability, etc.). This process should engage and solicit input from major industry end-users (for a view on demand measures), as well as energy infrastructure developers, along with Svenska Kraftnat, Nordion Energi and the Gas DSOs (for a view on supply measures).

4.3 **Establish a taskforce to investigate Hydrogen Contracts for Differences (CfDs).** The Government should establish a taskforce to investigate the application of CfDs in hydrogen production. The CfD Taskforce should be tasked with identifying CfD test-case projects, defining a CfD strike price and contract term, and exploring the regulatory implications and requirements to implement a CfD pilot.

4.4 **Implementation of a CfD Pilot**. Following the conclusions of the CfD Taskforce, the Government should instruct the Swedish Energy Agency to explore the launch of a CfD support pilot during an introductory phase for select 'high priority' hydrogen projects.

Figure 50 – Action Plan to Develop Market Condition for Hydrogen and Biomethane Investments



9.2.5 Preparing for a future hydrogen system

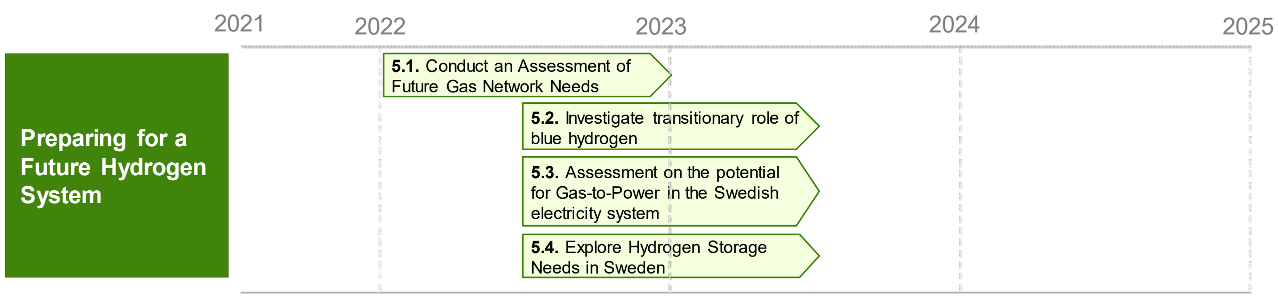
5.1 **1.1. Perform an Assessment of Future Hydrogen and Biomethane Network Needs.** Nordion Energi and the Gas DSOs should perform a gas grid capacity planning study to identify future gas network requirements. Results from our analysis identified a major role for gas infrastructure in enabling the supply and transport of biomethane and hydrogen to meet future demand. This "future gas network needs" assessment should develop a transition pathway of investments for the existing natural gas grid from Dragör (DK) to Stenungsund, along with regionalised outputs for individual gas distribution networks. An equivalent investment pathway should be also be developed for hydrogen supply and transmission infrastructure.

5.2 **Investigate transitionary role of blue hydrogen.** Early hydrogen offtakers will likely rely on the high-utilisation of blue hydrogen production to justify business cases and financing. The Swedish Energy Agency should explore and investigate implications (regulatory, financial, tax, and environmental) from the use of blue hydrogen given its major role in the supply of hydrogen ahead of the scale up of green hydrogen and its continuing role thereafter. This exercise may point to the need to facilitate the transition of industry end-users moving from blue to green hydrogen, for example by easing permitting processes.

5.3 **Assessment on the potential for Gas-to-Power in the Swedish electricity system.** Svenska Kraftnat and Nordion Energi should investigate the role of hydrogen to provide flexibility in the power system. The Swedish electricity system already has a significant degree of flexibility because of the high availability of reservoir hydro and the highly interconnected Nordic system. While hydrogen may not play a major role in energy supply, its role in delivering system flexibility has not been fully explored.

5.4 **Explore Hydrogen Storage Needs in Sweden.** Nordion Energi should examine future hydrogen storage needs for hydrogen clusters. Traditional gas storage generally takes 7 years to develop and faces development challenges if solely left to market conditions. This investigation should consider regulatory and market implications, such as the associated commercial risk.

Figure 51 – Action Plan to Prepare for a Future Hydrogen System



9.2.6 Creating an enabling regulatory environment

6.1 **Review of permitting processes for grid connection and environmental approvals.** The Government should instruct Svenska Kraftnat, the Energy Markets Inspectorate and the Swedish Environmental Protection Agency to, where possible, allow for permitting processes to run in parallel without jeopardizing quality and public trust. In its 2040 Roadmap, the Swedish Wind Energy Association identified that the connection process can better aligned with the permit process and the investment decision-making process for wind power developments.

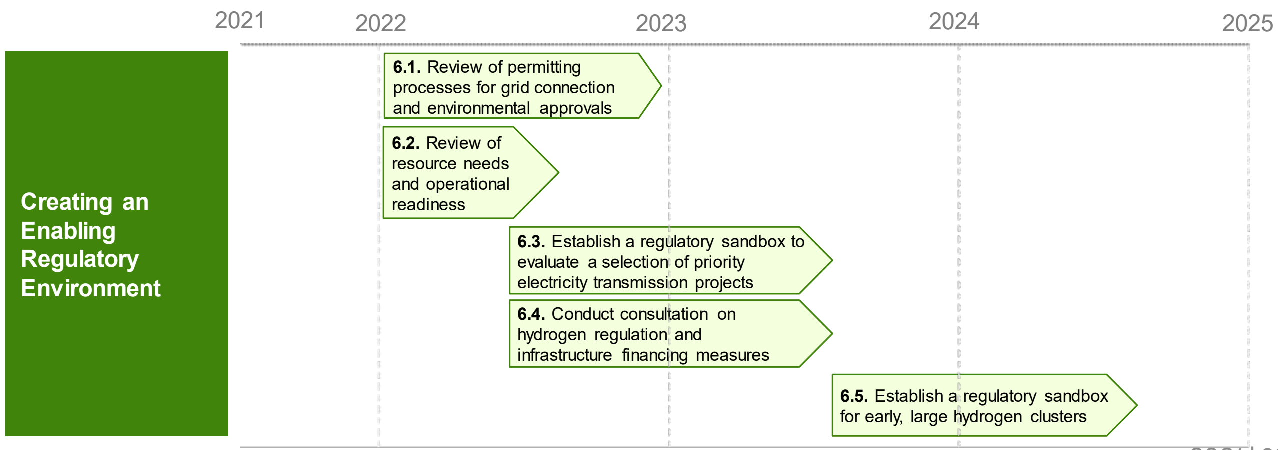
6.2 **Review of resource needs and operational readiness.** The Energy Markets Inspectorate should ensure it has the resource capacity required to efficiently manage and process a significant increase in generation and transmission projects. Our analysis projects electricity supply capacity will increase by more than 2x from roughly 40 GW of supply capacity today to c.86 GW by 2045. Evaluating, vetting, and approving (or rejecting) this magnitude of projects will be unprecedented. The Energy Markets Inspectorate has a pivotal role in the scale up of generation and transmission infrastructure and should receive the support required to efficiently manage and process an ever-increasing pipeline of projects.

6.3 **Establish a regulatory sandbox to evaluate a selection of priority electricity transmission projects.** The Energy Markets Inspectorate should create an adaptable evaluation framework (a "sandbox") to evaluate a selection of high-priority electricity transmission infrastructure projects. While there has been a lot of discussion about regulatory sandboxes, there is yet to be much action. Fossilfritt Sverige's hydrogen roadmap called for regulatory sandboxes for a selection of electricity and hydrogen infrastructure projects. Current bottlenecks on electricity grid capacity are excellent opportunities to "test and assess" changes to existing regulatory evaluation processes.

6.4 **Conduct consultation on hydrogen regulation and infrastructure financing measures.** The Energy Markets Inspectorate should initiate a consultation process with the aim of gathering stakeholder views on regulatory topics (e.g., infrastructure development, CBA framework, pipeline concessions, permitting processes, network access/costs, cross-subsidisation, etc.) and infrastructure financing approaches (e.g., regulatory asset base (RAB), offtaker financed, costs, etc.). The consultation process should also gather feedback on the extent that the existing natural gas framework (for concessions) can be used/repurposed for the hydrogen context.

6.5 **Establish a hydrogen regulatory sandbox.** Following the consultation process described above, the Energy Markets Inspectorate should create a sandbox for hydrogen infrastructure projects well ahead of the development of early industrial clusters developing. These early and large-scale hydrogen infrastructure projects should be leveraged as means of creating a regulatory sandbox.

Figure 52 – Action Plan to Prepare for a Future Hydrogen System



Gotenburg, Sweden

Appendix A

Detailed Transport Sector Decarbonisation

The transport sector is composed of three different sub-sectors: road transport, shipping, and aviation. Decarbonisation trends across of each of these sub-sectors are drastically different with different energy sources and fuel mixes. Nevertheless, since transport networks are regionally and globally interconnected, the types of vehicles adopted in Sweden and their associated charging & fuelling infrastructure will largely resemble global trends.

Both scenarios are characterised by common trends in light duty road transport and aviation. In light duty transport, EVs are by and large the prefer vehicle option, while in aviation – largely influenced by global trends – synthetic kerosene ("e-kerosene") and advanced biodiesel are the fuels of choice.

- In the **Major Gas** scenario, while EVs dominate light duty transport, hydrogen fuel-cell EVs (FCEVs) also play a role, however minimal, in niche delivery use cases. In heavy duty transport, hydrogen and LBG play an increasing role, complemented by electrification. In shipping, gas plays a dominant role through LBG and hydrogen-derived fuels like ammonia and methanol.
- In the **Limited Gas** scenario, light duty transport is fully electrified, with gas demand being limited to heavy, long-distance road transport. In shipping, unlike in the Major Gas scenario, biodiesel and electricity also play roles – with electricity being primarily used for coastal shipping and short-distance, commuter shipping. Gas alternatives, like LBG, ammonia and methanol, are predominantly limited to long-distance shipping.

Figure 53 – Decarbonisation of Transport by Demand Scenario

Major Role for Gas

TRANSPORT

Gas plays a significant role in all types of heavy transport; road, shipping, and aviation, but a very limited role in light duty transport.

- **Light duty road transport** is almost completely electrified, with hydrogen (in fuel-cell vehicles) playing a minor role. Passenger vehicles are assumed to be 95% EVs and 5% FCEVs, while light commercial vehicles are assumed to be 90% EVs and 10% FCEVs.
- In **heavy duty road transport**, hydrogen and bio-CNG/LNG play a major role, complemented by electrification. Buses are assumed to be 75% EVs and 25% FCEVs. Freight trucks are assumed to be 40% EVs, 30% FCEVs, 20% bio-CNG/LNG vehicles and 10% advanced biodiesel vehicles.
- In **shipping**, bio-LNG and hydrogen-derived ammonia and methanol play dominant roles in long-distance shipping. 50% of all long-distance shipping is assumed to use bio-LNG, while 25% is methanol and 25% ammonia. Domestic coastal shipping is assumed to be nearly fully electric.
- In **aviation**, both bio jet and hydrogen (used in the production of synthetic kerosene) play major roles; 60% and 40% respectively.

Limited Role for Gas

TRANSPORT

Gas plays a less prevalent role, with gas demand limited to heavy road transport and shipping.
Electrification plays a more dominant role.

- **Light duty transport** is completely electrified. Gas does not play any role. Both passenger vehicles and light commercial vehicles are assumed to be fully electric.
- **Heavy duty transport** is also mostly electrified. Gas demand is limited to bio-CNG/LNG use in trucks. Buses are assumed to be 85% EVs and 15% advanced biodiesel vehicles. Freight trucks are assumed to be 60% EVs, 10% bio-CNG/LNG vehicles and 30% advanced biodiesel vehicles.
- In **shipping**, electricity, biofuel, and bio-LNG all play major roles. Hydrogen-derived fuels do not play a role in shipping. 50% of all long-distance shipping is assumed to use advanced biodiesel, while 25% uses bio-LNG and 25% is electric. Domestic coastal shipping is assumed to be fully electric.
- In **aviation**, both bio jet and hydrogen (used in the production of synthetic kerosene) play major roles; 60% and 40% respectively.

While total energy demand decreases in both scenarios, demand for electricity, hydrogen and biomethane increases. While hydrogen and biomethane demand increases significantly in the Major Gas scenario, the Limited Gas scenario only sees a moderate increase.

Road transport

Energy demand declines steadily through 2045 from 83 TWh today down to 49 TWh in the Major Role for Gas scenario, and to 50 TWh in the Limited Role for Gas scenario. The decline in energy demand is largely a result of the level of electrification in light- and heavy-duty road transport as the fuel efficiency of EVs is significantly higher than traditional fuels like diesel or petrol. While electrification plays the most dominant role in road transport, the higher efficiency of EVs compared to combustion engines result in relatively moderate electricity demand compared to other less-efficiency fuels.

Shipping Energy demand declines steadily through 2045 from 27 TWh today down to 17 TWh in the Major Role for Gas scenario, and to 19 TWh in the Limited Role for Gas scenario. Much like with road transport, this decline is driven by increasing efficiencies.

Aviation Unlike road transport and shipping, energy demand remains at current levels, increasing slightly from 13 TWh to 14 TWh in both scenarios.

Note: These energy forecasts represent final energy demand by end-users, rather than primary energy demand. This means, these forecasts don't reflect electricity use in hydrogen production, rather only hydrogen demand by end-users.

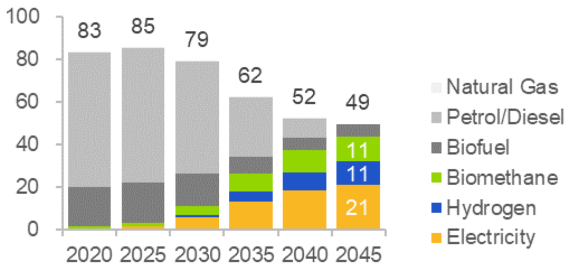
Figure 54 – Road Transport Energy Demand, by Demand Scenario

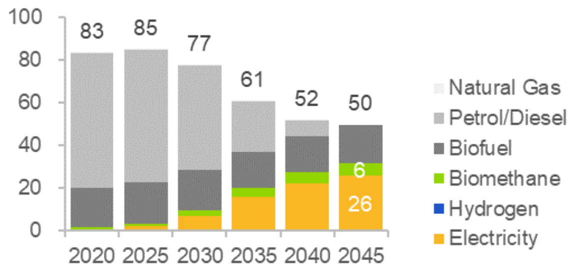
Major Role for Gas

- Energy demand decreases from 83 TWh down to 49TWh; however, gas volumes increase significantly, evenly across hydrogen and biomethane.
- Both hydrogen and biomethane increase to 11 TWh.

Limited Role for Gas

- Energy demand decreases from 83 TWh down to 50 TWh. Compared to the Major Gas scenario, gas volumes only increase moderately.
- Biomethane increases to 6 TWh while hydrogen does not play any role.



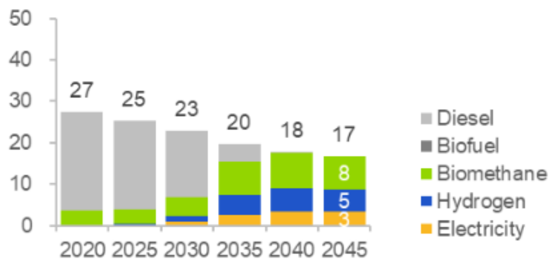


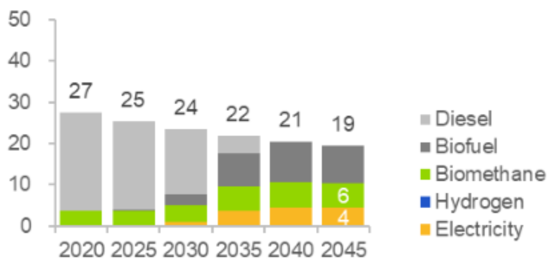
Regional Insights

- Energy demand for light- and heavy-road transport is distributed across Sweden in line with the distribution of population.
- Most energy demand for road transport is in SE3 – where major cities like Stockholm, Göteborg and Uppsala are located – and SE4 – where Malmö is located.

Figure 55 – Shipping Transport Energy Demand, by Demand Scenario

Major Role for Gas	Limited Role for Gas
• Energy demand decreases from 27 TWh down to 17TWh; however, both biomethane and hydrogen increase significantly • Biomethane increases to 8 TWh while hydrogen demand increases to 5 TWh. Electrification also plays a material role in the decarbonisation of shipping.	• Energy demand decreases from 27 TWh down to 19 TWh. Biomethane volumes increase to similar levels as the Major Gas scenario. • Biomethane increases to 6 TWh while hydrogen does not play any role. Liquid biofuels and electrification both play major roles.



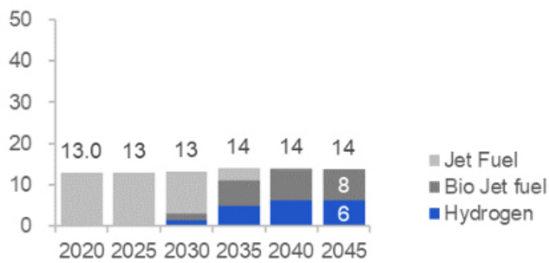


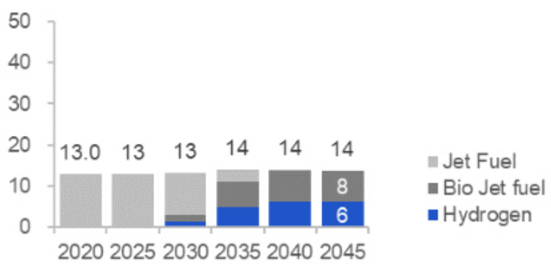
Regional Insights

- The location and distribution of energy demand for shipping is highly regional, dependent on where major shipping ports are located.
- Nearly 85% of energy demand for shipping is in SE3, where the ports of Stockholm, Göteborg and Donsö are located.

Figure 56 – Aviation Transport Energy Demand, by Demand Scenario

Major Role for Gas	Limited Role for Gas
• Energy demand remains relatively flat, increasing only slightly from 13 to 14 TWh. • Hydrogen increases to 6 TWh. Bio jet fuel also play a major role in the decarbonisation of aviation. Biomethane does not play a role in aviation.	• Energy demand remains relatively flat, increasing only slightly from 13 to 14 TWh. • Hydrogen increases to 6 TWh. Bio jet fuel also play a major role in the decarbonisation of aviation. Biomethane does not play a role in aviation.





Regional Insights

- The location and distribution of energy demand for aviation is highly regional and dependent on where major international and domestic airports are located.
- Nearly 90% of energy demand for aviation is in SE3 – where Stockholm's Arlanda, Bromma and Skavsta airports are located, along with the Göteborg-Landvetter airport.

Appendix B

Modelling Approach and Key Assumptions

The Low Carbon Pathways (LCP) model is an integrated capacity expansion and dispatch optimisation model that allows to identify the lowest cost, energy system pathway to a decarbonised future under different scenarios. The cost-optimisation engine of the LCP model minimizes the net present value of the total system costs over the analysed study time frame while considering various constraints at the energy system level (e.g., the buildout and availability of supply, the development of interconnections, etc.) as well operational constraints at the individual technology level (e.g., the operation of power generation plants, etc.)

In this project, Guidehouse applied the LCP model to optimise the supply of electricity, district heating, hydrogen and methane to meet energy demand determined in two demand scenarios, while meeting the 2045 Swedish decarbonisation targets.

The following describe some of the major features of the LCP model as applied in this project:

- **Capacity expansion & dispatch optimisation** | Optimisation of generation, storage and interconnections assets across the electricity, gas (methane and hydrogen) and district heating system
- **Lowest-cost net-zero pathway** | Optimised decarbonisation pathways to achieve net-zero carbon emissions targets in 2045
- **Intra-annual temporal resolution** | Uses representative and peak days to reflect the seasonal variability of demand loads and supply resources
- **Geographical resolution** | Simulates the Swedish energy system using four (4) interconnected regional nodes and three (3) neighboring systems – Norway, Finland & the Baltics, and Denmark & Central Europe.

B.1 Modelling approach for demand, supply and infrastructure

B.1.1 Electricity demand, supply and infrastructure

Energy Demand | Electricity demand in each Swedish region is defined by the demand scenarios, while electricity demand in non-Swedish regions is defined based on the TYNDP National Trends (NT) scenario.

- **Endogenous & exogenous demand** | Electricity demand defined by the demand scenarios is referred to as “exogenous demand”, since it is defined exogenously (e.g., external to the LCP model). In addition to exogenous electricity demand, there is also some additional electricity demand determined directly by the LCP model. This electricity demand is known as “endogenous demand”, since it is defined endogenously (e.g., internal to the LCP model). This electricity demand can arise from demand for hydrogen.

Supply Buildout | Electricity supply capacity in 2020 is defined by the TYNDP NT scenario. The buildout of electricity supply from 2020 to 2045 is optimised by the model. However, a baseline level of supply capacity expansion through 2045 is defined by the TYNDP NT scenarios for each Swedish region. The LCP model can choose to build additional supply capacity as required.

Interconnection Infrastructure | Electricity interconnection infrastructure between regions in 2020 is defined by the TYNDP NT scenario. Existing two-way transmission capacities are also accurately reflected in our analysis.

- **Between Swedish regions** | The buildout of infrastructure from 2020 to 2045 is optimised by the model. However, a baseline level of interconnection capacity expansion through 2045 is defined by the TYNDP NT scenarios for each Swedish region. The LCP model can choose to build additional interconnection capacity as required.
- **With non-Swedish regions** | The buildout of infrastructure from 2020 to 2045 is defined by the TYNDP NT scenario.

Table 11 – Modelling approach for demand, supply and infrastructure, electricity

	Energy Demand	Supply Capacity
Swedish Regions	Scenario-defined	Scenario-defined
Non-Swedish Regions	TYNDP-defined	Not modelled

	Interconnection Infrastructure
Between SE regions	TYNDP baseline + Model optimised
Between SE and Non-SE Regions	TYNDP-defined
Between non-SE Regions	TYNDP-defined

B.1.2 Hydrogen demand, supply and infrastructure

Energy Demand | Hydrogen demand in each Swedish region is defined by the Demand Scenarios. Hydrogen demand for non-Swedish regions is not defined. This configuration can have implications on modelling results. For example, hydrogen demand is not defined for non-Swedish regions, our analysis does not explore the potential role of Swedish hydrogen being exported to other countries.

- **Endogenous & exogenous demand** | Hydrogen use in power generation is not exogenously defined, rather, it is modelled endogenously by the LCP model. Nevertheless, our analysis did not result in hydrogen being used for power generation.

Sweden as a Hydrogen Exporter?

- Our analysis does not explore the potential role of Sweden acting as an exporter of hydrogen to other regions.
- The role of Sweden, and other Nordic countries, as a "hydrogen export hub" supplying demand centers in Central/Western Europe has received some recent traction. The low cost of electricity in northern Sweden, for example, has the potential to position Sweden as a cost-competitive source of hydrogen supply.
- Our analysis shows that nearly all hydrogen demand in Sweden will be supplied by domestic green hydrogen production. Much of this hydrogen supply capacity will be concentrated in the north of the country. Given that most hydrogen demand will be supplied via domestic production rather than hydrogen imports via Denmark, this demonstrates that hydrogen production in Sweden can be cost-competitive to other regions.

Supply Buildout | Hydrogen supply capacity in 2020 is estimated based on hydrogen demand, c.4 TWh. Based on this level of demand, our analysis assumes SMR capacity of approximately 600 MW_{H2}. The buildout of hydrogen supply capacity from 2020 to 2045 is optimised by the model. The model can choose to build additional SMR or electrolyser capacity as required. SMR capacity, however, can only be built n SE4 and SE3 – where existing methane infrastructure is available today. In our analysis, SMR cannot be deployed in SE1 or SE2 to meeting hydrogen demand. This is because we don't assume biomethane supply capacity will scale up with the purpose of then being used to produce hydrogen.

- **Electrolyser** | The efficiency of electrolysers is projected to increase over time. Any electrolysers installed in 2040-2045 are assumed to have a higher efficiency than electrolysers installed in 2030-2035, which in-turn have a higher efficiency than electrolysers installed in 2020-2025.
- **SMR** | Our model differentiates between SMR and SMR+CCS. While existing SMR does not have CCS capabilities, new SMR+CCS capacity can be installed in the future if needed, to meet a pathway of declining emissions down to net-zero by 2045.

Interconnection Infrastructure | No hydrogen interconnections exist today. The model can choose to build interconnections across Swedish regions as well as an interconnection with DK&CE for imports. An interconnection with Finland is not explored.

Hydrogen interconnection connecting Finland and Sweden?

- Our study does not analyse a potential hydrogen interconnection between SE1 and Finland. However, since more than 50% of hydrogen demand in Sweden is located in the north of country, in SE1, and large industrial cluster are also located in the north of Finland, a potential interconnection connecting hydrogen supply and demand centers has sparked some interest.
- Our analysis shows that hydrogen supply, to meet demand in SE1, will likely be located where electricity supply capacity is abundant, like in SE2. The development of an interconnection to supply hydrogen demand in northern Finland would potentially result in additional electrolyser capacity being installed in SE2 as well as increased interconnection capacity to transport larger hydrogen volumes, first into SE1 and then into Finland.

Table 12 – Modelling approach for demand, supply and infrastructure, hydrogen

	Energy Demand	Supply Capacity
Swedish Regions	Scenario-defined	Model Optimised
Non-Swedish Regions	Not modelled	Not modelled

	Interconnection Infrastructure
Between SE regions	TYNDP baseline + Model optimised
Between SE and Non-SE Regions	Only DK-SE4: Model-optimised
Between non-SE Regions	Not modelled

B.1.3 Methane demand, supply and infrastructure

Energy Demand | Methane demand in each Swedish region is defined by the demand scenarios. Methane demand for non-Swedish regions is not defined. As with hydrogen, this configuration can have implications on modelling results. However, since Sweden has relatively limited biomethane supply potential, it is highly unlikely that Sweden will export biomethane to neighboring regions.

- **Endogenous & exogenous demand** | Methane use in power generation and district heat is not exogenously defined, rather, it is modelled endogenously by the LCP model. Endogenous methane demand for power is observed in our results primarily over the 2020-2030 period. Endogenous methane demand for district heating continues to be needed until 2045.

Supply Buildout | Domestic biomethane supply capacity in 2020 is estimated at approximately 250 MW based on known biogas supply of c.2 TWh. The buildout of biomethane supply capacity from 2020 to 2045 is optimised by the model. The model can choose to build additional AD or bioSNG supply capacity up to a maximum limit of supply.

- **AD supply** is capped at 7 TWh by 2030 and 12.4 TWh by 2045. The 2030 cap is set based on the national production target defined by the governmental biogas market inquiry (Biogasmarknadsutredningen), and later adopted by the Energigas Sverige roadmap[27]. The 2045 cap is set based on the Swedish supply potential identified by several studies and summarised by IVL. We used the average across all of the studies referenced by the IVL report[28].
- **BioSNG supply** is capped at 3 TWh by 2030 and 4.8 TWh by 2045. The 2030 cap is also set based on the Biogasmarknadsutredningen, which although doesn't explicitly state 3 TWh is the BioSNG potential – rather made up of various other sources – we adopt as the upper limit of supply. Nevertheless, our results don't show BioSNG supply capacity scaling up until after 2030. The 2045 cap is set by assuming BioSNG supply potential could, at a maximum, scale at the rate of AD supply: 1.8x from 2030 to 2045.

Interconnection Infrastructure | Methane import capacity exists today from DK stretching into SE4 and SE3. No interconnection existing with SE2 and SE1. The model can choose to expand import.

[27] Available here: https://www.energigas.se/library/2767/gasbranschens-faerdplan.pdf

[28] Available here: https://www.researchgate.net/publication/282275140_Potential_of_Biogas_Expansion_in_Sweden-_Identifying_the_Gap_between_Potential_Studies_and_Producer_Perspectives

Table 13 – Modelling approach for demand, supply and infrastructure, methane

	Energy Demand	Supply Capacity
Swedish Regions	Scenario-defined	Model Optimised
Non-Swedish Regions	Not modelled	Not modelled

	Interconnection Infrastructure
Between SE regions	TYNDP baseline + Model optimised
Between SE and Non-SE Regions	Only DK-SE4: Model-optimised
Between non-SE Regions	Not modelled

B.1.4 District heating demand, supply and infrastructure

Energy Demand | District heating demand in each Swedish region is defined by the demand scenarios. Heating demand for non-Swedish regions is not defined.

Supply Buildout | The district heating supply capacity mix was estimated based on the TYNDP NT scenario and was also complemented by a review of other secondary resources. The buildout of district heating supply from 2020 to 2045 is optimised by the model.

Interconnection Infrastructure | District heating interconnections are not permitted. District heating must be produced and consumed within each region.

Table 14 – Modelling approach for demand, supply and infrastructure, district heating

	Energy Demand	Supply Capacity
Swedish Regions	Scenario-defined	Model Optimised
Non-Swedish Regions	Not modelled	Not modelled

	Interconnection Infrastructure
Between SE regions	For DH, interconnections across regions were not allowed.
Between SE and Non-SE Regions	
Between non-SE Regions	

B.2 Technology cost assumptions

B.2.1 Electricity supply technology costs

Table 15 – Electricity supply technology costs

Year	Cost Component	Unit	Wind Onshore	Wind Offshore	Solar PV	OCGT CH4	CCGT CH4	OCGT H_2	CCGT H_2	CHP CCGT CH4	CHP CCGT H2	CHP ST Biomass	Battery Storage (4-hr)
2025	CAPEX	[kEUR/MW]	1100	2500	800	440	750	440	750	975	975	3000	270
	Fixed O&M	[kEUR/MW/y]	22	38	18	13	15	13	15	20	20	111	6.75
	Variable O&M	[kEUR/MWh]	0	0	0	1.6	1.6	1.6	1.6	1.6	1.6	3.3	0
	Lifetime	[year]	25	25	25	25	25	25	25	25	25	25	15
	Efficiency (LHV)	[%]	100	100	100	42	60	42	60	48	48	30	85
2035	CAPEX	[kEUR/MW]	800	1530	540	440	750	440	750	975	975	3300	230
	Fixed O&M	[kEUR/MW/y]	17	23	13	13	15	13	15	20	20	122.1	5.75
	Variable O&M	[kEUR/MWh]	0	0	0	1.6	1.6	1.6	1.6	1.6	1.6	3.3	0
	Lifetime	[year]	25	25	25	25	25	25	25	25	25	25	20
	Net Efficiency	[%]	100	100	100	42	60	42	60	48	48	30	85
2045	CAPEX	[kEUR/MW]	705	1333	440	440	750	440	750	975	975	3300	200
	Fixed O&M	[kEUR/MW/y]	17	20	12	13	15	13	15	20	20	122.1	5
	Variable O&M	[kEUR/MWh]	0	0	0	1.6	1.6	1.6	1.6	1.6	1.6	3.3	0
	Lifetime	[year]	25	25	25	25	25	25	25	25	25	25	20
	Net Efficiency	[%]	100	100	100	42	60	42	60	48	48	30	85

Sources for Wind, Solar PV, OCGT and CCGT

- ENTSO-E/G (2020). Available here: https://www.entsos-tyndp2020-scenarios.eu/wp-content/uploads/2020/07/TYNDP_2020_Scenario_Building-Guidelines_03_Annex_2_Cost_Assumptions_final_report.pdf
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Sources for CHP and Biomass

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Battery Storage:

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- NREL (2019). Available here: https://atb.nrel.gov/electricity/2019/index.html?t=st#rx4fcz6p

B.2.2 Hydrogen supply technology costs

Table 16 – Hydrogen supply technology costs

Year	Cost Component	Unit	Electrolysers	SMR + CCS
2025	CAPEX	[kEUR/MW]	600	1530
	Fixed O&M	[kEUR/MW/y]	12	45.9
	Variable O&M	[kEUR/MWh]	0	5.5
	Lifetime	[year]	25	25
	Efficiency (LHV)	[%]	67	69
2035	CAPEX	[kEUR/MW]	400	1340
	Fixed O&M	[kEUR/MW/y]	8	40.2
	Variable O&M	[kEUR/MWh]	0	5.5
	Lifetime	[year]	25	25
	Net Efficiency	[%]	70	69
2045	CAPEX	[kEUR/MW]	300	1300
	Fixed O&M	[kEUR/MW/y]	6	39
	Variable O&M	[kEUR/MWh]	0	5.5
	Lifetime	[year]	25	25
	Net Efficiency	[%]	73	69

Sources

- Guidehouse (2020). Available here: https://op.europa.eu/en/publication-detail/-/publication/7e4afa7d-d077-11ea-adf7-01aa75ed71a1/
- EWI (2020). Available here:https://www.ewi.uni-koeln.de/cms/wp-content/uploads/2020/11/EWI_WP_20-04_Estimating_long-term_global_supply_costs_for_low-carbon_Schoenfisch_Braendle_Schulte-1.pdf
- IEA (2019). Available here:https://iea.blob.core.windows.net/assets/29b027e5-fefc-47df-aed0-456b1bb38844/IEA-The-Future-of-Hydrogen-Assumptions-Annex_CORR.pdf
- McKinsey (2021). Available here: https://hydrogencouncil.com/wp-content/uploads/2021/02/Hydrogen-Insights-2021.pdf

Table 17 – Methane supply technology costs

Year	Cost Component	Unit	Anaerobic Digestion	Biomass Gasification
2025	CAPEX	[kEUR/MW]	2165	2595
	Fixed O&M	[kEUR/MW/y]	216	265
	Variable O&M	[kEUR/MWh]	43	52
	Lifetime	[year]	25	20
2035	CAPEX	[kEUR/MW]	2049	2119
	Fixed O&M	[kEUR/MW/y]	178	227
	Variable O&M	[kEUR/MWh]	38	47
	Lifetime	[year]	25	20
2045	CAPEX	[kEUR/MW]	1934	1642
	Fixed O&M	[kEUR/MW/y]	141	190
	Variable O&M	[kEUR/MWh]	33	42
	Lifetime	[year]	25	20

Sources

- Guidehouse (2019). Available here: https://gasforclimate2050.eu/wp-content/uploads/2020/03/Navigant-Gas-for-Climate-The-optimal-role-for-gas-in-a-net-zero-emissions-energy-system-March-2019.pdf

B.2.4 Interconnection distances

Transmission infrastructure costs for electricity, hydrogen and methane interconnections are "normalized" based on capacity and distance and expressed in Million EUR / MW-km units. To determine the costs of expanding existing interconnections or building new ones, these normalised costs are multiplied by the average distance from one region to another.

The tables below show the distances assumed from one region to another, along with interconnection costs of electricity, hydrogen and methane infrastructure.

Table 18 – Average distance between Swedish regions

Region A	Region B	km
SE1	SE2	400
SE2	SE3	500
SE3	SE4	300
SE4	DK&CE	200

Source: Guidehouse estimate based on the location of the geographic centre of each region

B.2.5 Electricity interconnection costs

The electricity infrastructure costs used in our analysis reflect the cost of building new overhead transmission lines. These costs are presented in the table below.

We also evaluated the impact on results based on lower and higher costs. Lower infrastructure costs reflected the cost of upgrading / reinforcing existing overhead lines, while higher infrastructure costs reflected the costs of building new underground high-voltage DC (HVDC) lines.

In both cases, the impact on results were negligible, with no material impact on the development of hydrogen supply or infrastructure.

Table 19 – Electricity infrastructure investment cost inputs by transmission line type

Cost Component		New Overhead Line	Upgrade / Reinforcement	High-Voltage DC (HVDC)
CAPEX	€/ MW-km]	250	150	1,950

Source

- New Overhead Line: CIGRE (2019). Available here: https://e-cigre.org/publication/775-global-electricity-network-feasibility-study
- Upgrade / Reinforcement: Estimated at 60% of costs for new overhead line. Assumption based on: https://iopscience.iop.org/article/10.1088/1757-899X/881/1/012044/pdf
- HVDC: IEA (2016). Assumes underground DC cable with a max distance of 300 km for M€0.58 per MW. For distances longer than 300km, we scale up the costs proportionally. Available here: https://www.nordicenergy.org/wp-content/uploads/2015/12/Nordic-Energy-Technology-Perspectives-2016.pdf

The costs of new overhead transmission lines (shown above) were used to define transmission CAPEX and OPEX across all regions (as shown below).

Table 20 – Electricity infrastructure investment costs

Region A	Region B	CAPEX *€/ MW-km*	OPEX *% of CAPEX*
SE1	SE2	250	1%
SE2	SE3	250	1%
SE3	SE4	250	1%

Source

- CAPEX: CIGRE (2019). Available here: https://e-cigre.org/publication/775-global-electricity-network-feasibility-study
- OPEX: Guidehouse assumption

B.2.6 Hydrogen interconnection costs

The hydrogen infrastructure costs used in our analysis reflect the cost of building new 36-inch pipelines. These costs are presented in the table below.

These costs are estimated based on the experience of European gas TSOs with hydrogen infrastructure and based on their experience operating and constructing natural gas infrastructure. As reference below, these infrastructure costs figures are sourced from the European Hydrogen Backbone report.

In addition to 36-inch pipeline costs, we also evaluated results based on lower and higher pipeline costs. Lower infrastructure costs reflected the cost of building 48-inch pipelines, while higher infrastructure costs reflected the costs of building 20-inch pipelines. The Low H_2 Infrastructure Cost sensitivity analysis is based on the cost of 48-inch pipelines.

Based on the level of hydrogen demand in Sweden, our analysis shows that, in general terms, 36-inch transmission pipelines may be the most appropriate size across much of the country. 20-inch pipelines will likely not be sufficient based on demand volumes transported across SE1 and SE3, however may be sufficient in SE4. In contrast, the volumes of hydrogen demand do not justify the development of 48-inch transmission pipelines.

Table 21 – Hydrogen infrastructure investment cost inputs by transmission pipe line size

Cost Component		48in Pipeline (New)	36in Pipeline (New)	20in Pipeline (New)
Capacity (LHV)	[GW]	13	4.7	1.2
Pipeline Costs	[Million €/km]	2.8	2.2	1.5
Compression Costs	[Million €/km]	0.62	0.32	0.09
Total Costs	[Million €/km]	3.42	2.52	1.59
Normalised Costs	[€/MW-km]	**263**	**536**	**1,325**

Source

- Guidehouse (2021). Available here: https://gasforclimate2050.eu/sdm_downloads/european-hydrogen-backbone/

Table 22 – Hydrogen transmission investment costs

Region A	Region B	CAPEX *€/ MW-km*	OPEX *% of CAPEX*
SE1	**SE2**	536	1%
SE2	**SE3**	536	1%
SE3	**SE4**	536	1%
SE4	**DK&CE**	536	1%

Source

- CAPEX: Guidehouse calculation based on Table 9 (Hydrogen Transmission Investment Detailed Cost Inputs)
- OPEX: Guidehouse assumption

Comparison of transmission cost between pipelines and power lines

The conversion of electricity to hydrogen via electrolysis can occur in two ways: (1) at the location of electricity production; or (2) at the location of hydrogen consumption. The first method assumes hydrogen is transported to the consumption site via pipeline, while the second method assumes power lines are used to transport electricity to the consumption site, where conversion to hydrogen takes place.

The July-2020 European Hydrogen Backbone (EHB) report determined that while both methods have their benefits and trade-offs, transport via pipelines is generally 2 to 4 times more cost-effective than power lines. This finding was determined based on a large number of hydrogen and electricity transmission configurations. The EHB study compared the costs of 48-inch, 36-inch and 20-inch hydrogen pipelines – both new and repurposed – with the costs of overhead and underground HVAC lines, as well as underground HVDC lines.

The pipeline and power line cost assumptions used in this study – and presented above – are largely consistent with the EHB assumptions. To arrive at the conclusion that pipelines are generally more cost-effective than power lines, a simple comparison of hydrogen pipeline costs and electricity transmission costs is not sufficient. Several corrections and adjustments are required.

Most notably, electricity transmission costs must be adjusted to account for electrolyser conversion losses: the conversion from electrons to hydrogen molecules that occurs at the consumption site. This means power line costs have to be divided by the efficiency of electrolysers because power lines need to be oversized to compensate for electrolyser losses at the end of the line (e.g., costs are divided by 65%). A few other corrections are also needed; for example, the utilisation of electricity lines is typically much lower than pipelines, differences in line losses in electricity transport vs. hydrogen transport, etc. The EHB report provides additional explanation related to some of these corrections.

The EHB conclusion regarding hydrogen pipelines being more cost-effective than power lines is demonstrated by the results of our analysis. Across all scenarios and sensitivities, our results show that a significant share of electrolyser capacity will be installed at locations of electricity production and transported to consumption sites via pipelines. This is particularly true in SE2, where our analysis shows significant electrolyser capacity being installed to utilise an oversupply of electricity production. Hydrogen produced in SE2 is then transported to consumption sites in SE1 and SE3 via pipelines.

The decision-making process of whether to invest in a hydrogen pipeline or not is also driven by non-cost drivers. For example, the magnitude of gas volumes transported through a pipeline has a significant impact on the overall profitability and business case of the pipeline itself, much like the local geological and terrain characteristics of each region could also have an impact on costs.

B.2.7 Methane interconnection costs

Consistent with cost inputs for hydrogen infrastructure, we also adopted figures from the European Hydrogen Backbone report to develop cost inputs for natural gas (methane) transmission infrastructure. As with hydrogen, the basis for our cost assumptions reflect the cost of building 36-inch gas pipelines. We also cross-checked our gas transmission costs with publicly available "all-in" costs obtained from a meta-analysis benchmark report developed by ACER, the EU Agency for the Cooperation of Energy Regulators.

The gas transmission costs we adopted are based on cost-multipliers for pipelines and compressors, comparing the price differential of developing natural gas vs. hydrogen infrastructure. For example, new hydrogen pipeline costs (presented above) are estimated to range between 110% and 150% vs. natural gas pipeline costs. Similarly, hydrogen compressor costs are estimated to range between 140% and 180% vs. natural gas compressors. An adjustment to compressor costs is also required to account for the fact that hydrogen has a lower energy density than natural gas (at the same pressure), in turn requiring hydrogen compressors to operate at a higher pressure. This ultimately results in hydrogen infrastructure transporting up to c.80% of the energy capacity compared to natural gas infrastructure. Based on these inputs, we estimated natural gas infrastructure costs at €378/MW-km.

After estimating these costs, we cross-checked them with the ACER (2015) benchmark study. ACER reviewed investment cost from 293 transmission pipelines and 101 compressor stations put in service from 2005 to 2014. Based on this review, ACER estimate an average investment cost of M€1.1/km for 28 to 35-inch pipelines and M€1.5/km for 36 to 47-inch pipelines. Assuming a capacity of 4.7 GW (as assumed above for a 36-inch hydrogen pipeline) in both cases, for simplicity, the normalised costs are €230/MW-km (for 28-35-inch) and €310/MW-km (for 36-47-inch). While these costs are lower than our estimate, they do not reflect increased costs for subsea pipelines (like the Dragor pipeline), nor are adjusted for inflation to reflect current day euros (real terms).

Table 23 – Methane infrastructure investment cost vs. hydrogen

Cost Component		Hydrogen (36-inch)	Methane (36-inch)
Pipeline (New)	[€/MW-km]	468	380
Compressor (New)	[€/MW-km]	68	18
Total Costs	[€/MW-km]	**536**	**378**

Source

- Guidehouse (2020). Available here: https://gasforclimate2050.eu/sdm_downloads/european-hydrogen-backbone/
- Cross-checked with ACER (2015). Available here: https://www.acer.europa.eu/official_documents/acts_of_the_agency/publication/uic%20report%20-%20gas%20infrastructure.pdf

Table 24 – Methane infrastructure investment cost

Region A	Region B	CAPEX *EUR / MW-km*	OPEX *% of CAPEX*
SE1	**SE2**	378	1%
SE2	**SE3**	378	1%
SE3	**SE4**	378	1%
SE4	**DK&CE**	378	1%

Source

- CAPEX: Guidehouse (2021). Available here: https://gasforclimate2050.eu/sdm_downloads/european-hydrogen-backbone/
- OPEX: Guidehouse assumption

B.3 Additional modelling considerations

B.3.1 Hydrogen storage

Our analysis assumes Lined Rock Caverns (LRC) as the only candidate technology for hydrogen storage in Sweden. We assume LRCs can be installed "on demand", as need, in any of the four Swedish regions. Aside from LRC potential, Sweden has no large-scale gas storage sites that could be repurposed for hydrogen use.

Sweden is home to the world's first LRC-bases natural gas storage site. This storage facility, located in the southwest near Skallen, had historically been used to meet short-term peak demand until 2018. The site has an approximately volume of 40,000m3, providing roughly 90 GWh of storage (at 20MPA), with a full withdrawal period of 10-days (equivalent to roughly 9 GWh/day)[29]. While the Skallen LRC site is currently out of operation, it can be put back into service as needed.

There is currently a small-scale, LRC demonstration pilot under construction in Lulea[30]. An industry consortium made up of SSAB, LKAB and Vattenfall are building a 100m3 facility 30 meters underground to test the technology and develop operational experience. The long-term view of this pilot is that it will ultimately lead to the development to a much larger GWh-scale facility.

B.3.2 Seasons and temporal dimension

Our analysis uses five (5) 24-hour periods to optimise the hourly dispatch of energy supply resources to match hourly demand. Of these five, four represent seasonal days – winter, spring, summer and fall – used to reflect the seasonal variability of demand loads and energy supply resources in Sweden as well as in neighbouring jurisdictions. The fifth 24-hour period is a winter peak day intended to reflect the higher than average demand for electricity, methane and district heating on the day of highest energy demand.

Table 25 – Characterisation of seasons and days

Season	Order	Days
Winter	1	91
Winter Peak	2	1
Spring	3	91
Summer	4	91
Fall	5	91

In general, we averaged seasonal supply and demand profiles and adopted those for each season. For intermittent resources like onshore and offshore wind, solar and run-of-the-river hydro, we did not average supply shapes over entire seasons as this would produce smooth shapes. Rather, we analysed hourly supply profiles obtained from the Pan-European Climate Database (PECD) for each Swedish region and for neighboring regions to identify representative days realistic supply profiles. We visually inspected the supply profiles of the top-3 "best-match" days in each season. The supply shapes in these days were best aligned in terms of daily supply output to the seasonal average supply output. Using these 3 days, we then selected a single day for each season with the most realistic and reasonably shaped profiles. These supply shapes were used in our analysis.

[29] Available here: http://members.igu.org/html/wgc2006/pdf/paper/add10623.pdf

[30] Available here: https://www.svt.se/nyheter/lokalt/norrbotten/snart-borjar-sprangningarna-for-bygget-av-vatgaslagret-i-lulea

B.3.3. Fuel prices and taxes

The analysis incorporates energy costs and CO_2 prices as part of the calculation of total energy system costs and the cost-optimisation through 2045. Energy costs and CO_2 prices (EU ETS) are based on assumptions from Svenska Kraftnat, ENTSO-E/G TYNDP 2020 and the IEA WEO 2020.

The existing Swedish energy and CO_2 taxes are not considered when optimising the least-cost pathway to meet energy demand over the study time frame. The reason for this is that the current tax system might change over time and that any changes would have a strong impact on calculated

results. To avoid this situation, our analysis focuses on costs and neglects taxes. The currently developed NCES follow the same approach.

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THE ROLE OF GAS AND GAS INFRASTRUCTURE IN SWEDISH DECARBONISATION PATHWAYS 2020-2045

Sweden has set ambitious climate and energy targets to decarbonise its economy and energy system, and to achieve net-zero carbon emissions by 2045. To date, Sweden has already made significant progress in decarbonising the energy system, with much of its electricity and heating supply mix already made up of low-carbon and renewable energy.

Low-carbon and renewable gases like green hydrogen and biomethane – and their derivatives – have significant potential to play an enhanced role in the decarbonisation of the Swedish energy system, displacing fossil fuels from what would otherwise be hard-to-abate sectors. This report explores the role of renewable and low-carbon gas, and gas infrastructure, in a future climate-neutral Swedish energy system up to 2045.

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