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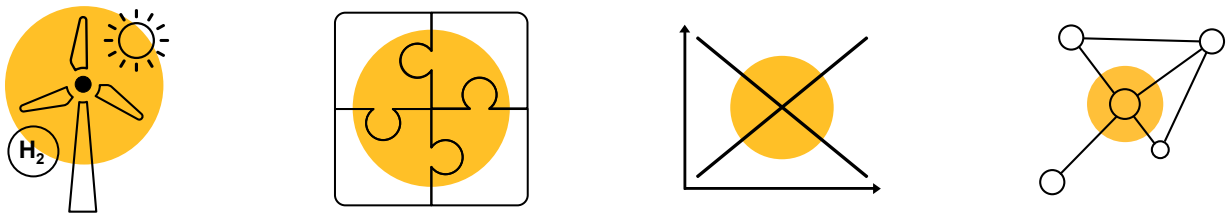
EWI-Report

19.10.2026

Iron as an Energy Carrier

Assessing the Potential of an Additional Decarbonization Option for a Secure and Affordable Net-Zero System

On behalf of:
Technical University of Darmstadt and
DESERTEC Foundation



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Please cite as:

EWI (2026): Iron as an Energy Carrier - Assessing the Potential of an Additional Decarbonization Option for a Secure and Affordable Net-Zero System

A model-based analysis of the European energy system with iron available as an energy carrier shows the following:



Iron as an energy carrier can be part of a cost-optimal decarbonized energy system.

Cost savings can be realized by utilizing iron as an energy carrier for storage to decarbonize dispatchable electricity and heating.



Retrofitting of existing (combined heat and) power plants realizes significant cost benefits in providing electricity and district heating compared to building new power plants.

Countries with large lignite and coal capacities could save substantially from retrofitting to iron power plants.



Long-term storage of fluctuating renewable electricity can be made more cost-efficient compared to hydrogen storage using iron as an energy carrier.



Local generation of hydrogen and iron together with abundant domestic renewable electricity can reduce the European dependence on energy imports. This requires sufficient electrolysis and iron reduction capacity.

Iron imports could partially substitute in case of a reduced renewable electricity buildout in Europe.



The availability of iron as an energy carrier could mitigate risks in constructing a decarbonized energy system.

These risks comprise technology readiness, availability of infrastructure, and business models, which also apply to iron.

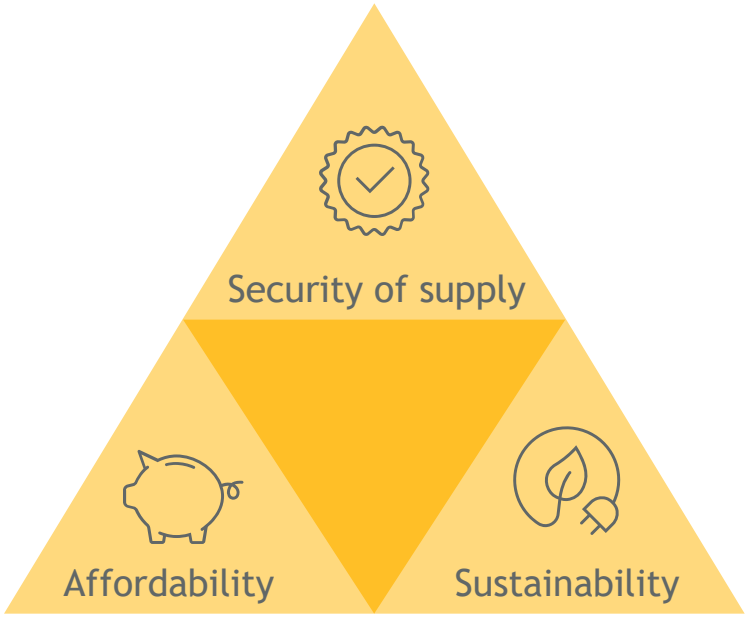
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Cost-optimal pathways to decarbonize Europe's energy system: Current strategies and studies focus on Hydrogen and CCS

Current situation

- To meet the legally binding climate targets, a decarbonization of the energy system to a state with net-zero emission is necessary. While the decarbonization emphasizes the role of sustainability, the other aspects of the energy policy triangle, security of supply and affordability, should be considered.
- The decarbonization of the energy system in Europe is largely driven by the deployment of variable renewable energy (VRE) sources and flexibility options, such as battery storage or demand response. However, to enable security of supply, dispatchable net-zero generation technologies need to be deployed in a net-zero energy system.
- In current scenarios, hydrogen-fired power plants are often pictured as main dispatchable generation technology to fully decarbonize the power sector.[1,2,3] In these scenarios, hydrogen is produced by electrolyzers in Europe or imported from outside of Europe, transported via a hydrogen transmission grid and seasonally stored in hydrogen storage systems.
- In some scenarios, natural-gas-fired power plants with carbon capture and storage (CCS) are also shown as possible technology to provide dispatchable capacity. For these, a transport infrastructure is built up to transport CO_2 to underground storages for long-term storage of CO_2.

The Energy Policy Triangle



1: ENTSO-E (2026) | 2: Fraunhofer ISI et al. (2025) | 3: EWI et al. (2022)

The outlined plans in these scenarios are subject to three main implementation challenges

Technology availability

- The scenarios for the future European energy system assume technological availability for several currently non-established technologies.
- For example, many studies assume that existing natural gas infrastructure in the form of pipelines, regasification terminals, cavern storages as well as gas turbines can be repurposed for hydrogen usage.
- Furthermore, for CCS it is assumed that carbon capture units, CO_2 pipelines as well as permanent underground CO_2 storages are technically feasible.
- However, it is not given that all of these different technological advancements are fully available by the time they are needed.

Construction of infrastructure

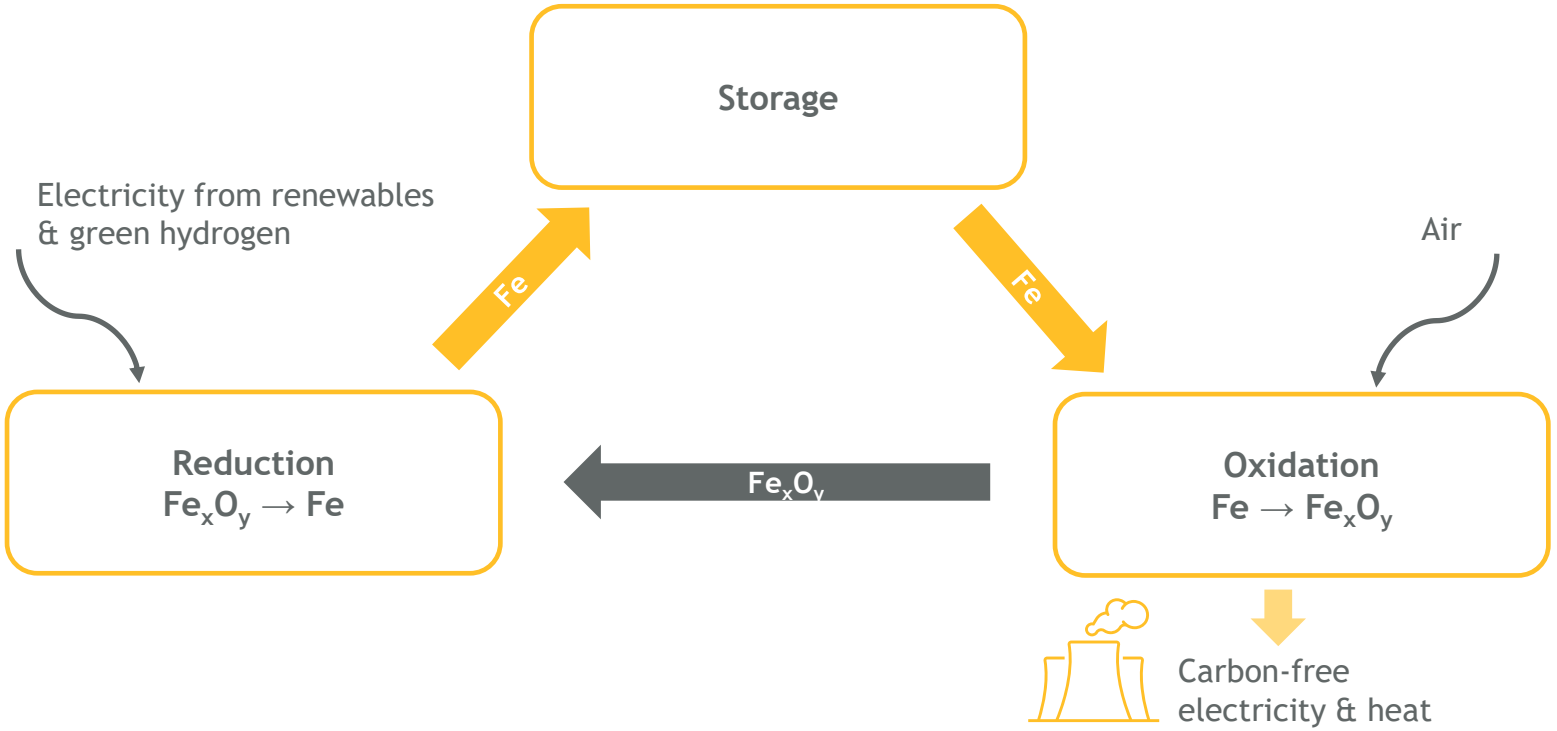
- If the technologies are generally available, the infrastructure, e.g. power plants, networks, and storage, needs to be built. This will require overcoming various challenges related to costs, financing, supply chains, construction time and public acceptance.
- For example, a hydrogen transmission network needs to be established with uncertain demand developments. For this, financing needs to be secured, a transition schedule must be established for gas pipelines that are still in use, and a supply chain with the necessary technical components needs to be in place.
- If one of these aspects is not guaranteed at the right time, the necessary infrastructure might be delayed.

Availability of energy

- If the infrastructure is built up in time, enough energy needs to be available. With weather-dependent variable renewable generation and new import routes, substantial energy storage is required to always satisfy demand.
- For example, in an energy system mostly depending on hydrogen-fired power plants for firm capacity, it is necessary to maintain a sufficient supply of hydrogen for the case of prolonged renewable energy droughts. For this, enough storage capacity with enough withdrawal capacity needs to be built.
- For new import routes, geopolitical and market power risks need to be assessed.
- Energy needs to be available at price levels corresponding to the willingness to pay.

Iron powder, produced with electricity from renewables, is an additional technology option for net-zero dispatchable generation

Circular iron process with electricity from renewables[1]



Comments

- Iron powder is another technology option for net-zero dispatchable power generation.
- In the production process, iron oxide is reduced with hydrogen, yielding iron in solid, pulverized form and water. No water is stored with the energy carrier.[2]
- The iron powder can later be oxidized by combustion with air, releasing high-temperature heat for electricity and heat generation.
- Since the combustion yields iron oxide and no carbon is involved, the process is fully circular and climate-neutral.
- The model ignores the possibility to reverse the iron reduction to produce hydrogen (steam-iron route). Its potential to also serve hydrogen demand is not captured.

1: Schematic representation based on Metal Energy Hub and Clean Circles (TU Darmstadt) | 2: Schuler et al. (2026)

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Iron powder may offer cost advantages compared to hydrogen and natural gas with CCS due to its solid form

	Iron powder	Hydrogen	Natural gas & CCS
Physical properties	• Solid, pulverized powder • Volumetric energy density comparable to or higher than coal	• Gaseous • Low volumetric energy density even when compressed or liquefied	• Gaseous (CH_4 & CO_2)
Transport	• Existing bulk-carrier infrastructure (ships, rail, trucks)	• Repurposing of natural gas pipelines or terminals • Newly built hydrogen pipelines or terminals	• Natural gas transport established • Newly built dedicated CO_2 pipelines
Storage	• Simple, low-cost above-ground storage in a silo • No pressurization, cooling or boil-off	• Geological storage in salt cavern • Power capacity is cost-driving compared to energy capacity	• Established natural gas storage • Permanent CO_2 storage in depleted natural-gas fields or other geological formations
Electricity and heat generation	• Retrofit of old coal and lignite power plants • Newly built power plants	• Retrofit of natural-gas-fired OCGT and CCGT plants[2] • Newly built OCGT / CCGT plants	• Existing natural-gas-fired CCGT plants with CO_2 capture retrofit • Newly built CCGT power plants
Efficiency[3]	• Iron powder generation requires around 1.4 kWh_{el} per kWh_{iron} • With reconversion efficiencies of 0.42 - 0.47 kWh_{el}/kWh_{iron}, around 3.0 – 3.4 kWh_{el} input are needed for 1 kWh_{el} output	• Hydrogen generation requires around 1.35 kWh_{el} per $kWh_{Hydrogen}$ • With reconversion efficiencies of 0.35 – 0.6 $kWh_{el}/kWh_{Hydrogen}$, around 2.25 – 3.9 kWh_{el} input are needed for 1 kWh_{el} output	• Conversion efficiencies of OCGT + CCS plants vary narrowly between 0.49 - 0.51 $kWh_{el}/kWh_{Natural\ gas}$.

Comments

- Iron powder offers advantages in handling and storage with potential cost savings compared to hydrogen and CCS.
- Due to iron's low gravimetric energy density, iron transport is not necessarily cheap.[1] However, transport costs from long-distance shipping are comparatively low. Furthermore, existing transport infrastructure can be used, lowering investment needs.
- Iron is stored in silos and therefore has low associated handling costs, even in small scale.
- The solid, pulverized powder form of iron resembles coal dust. Therefore, old coal and lignite power plants can be retrofitted to generate electricity from iron powder.

1: With the same energy content, iron is three to five times heavier than hard coal and 1.4 to 2.7 times heavier than lignite, Debiagi et al. (2022) | 2: Open/Combined Cycle Gas Turbine (OCGT/CCGT) | 3: Water and iron requirements are not considered here.

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We therefore ask the question: How would the availability of iron powder influence potential decarbonization pathways?

We analyze the main research question with regard to three aspects…



What is the cost-optimal mix of dispatchable power generation given the availability of iron-fired plants?



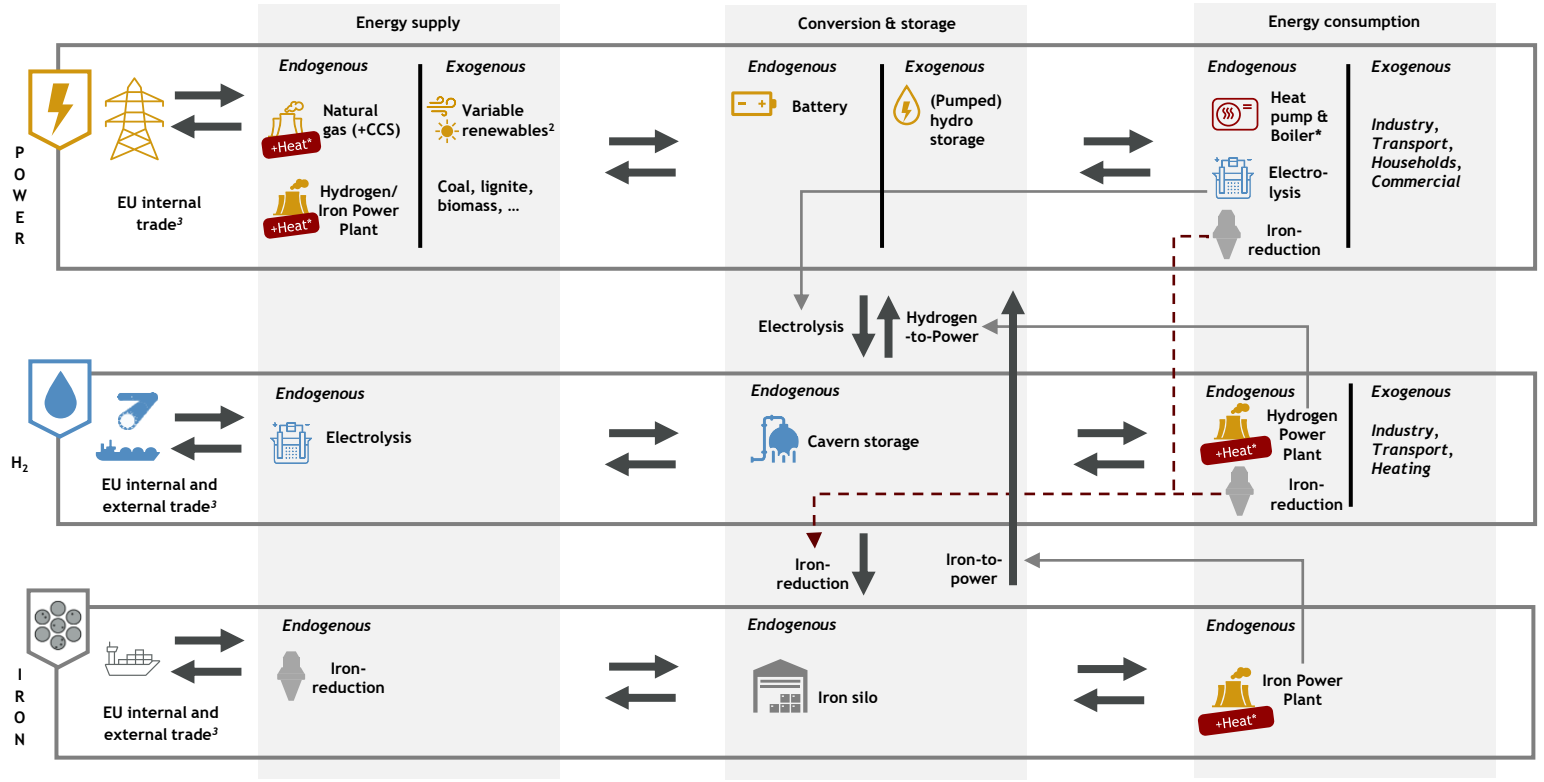
Would iron-fired combined heat and power stations affect cost-optimal district heat supply?



Does the availability of iron impact the cost-optimal domestic production, import, and storage of energy commodities?

The EWI-model HYEBRID is used to assess the potential of iron as additional decarbonization option to meet climate targets

Schematic of the energy system model HYEBRID[1]



Comments

- HYEBRID[4] is a linear optimization model that minimizes total system costs by optimizing investment in and dispatch of generation and storage technologies to meet electricity, hydrogen, and district heating demand.
- Total costs include annualized investment costs, fixed operation and maintenance costs as well as variable costs of generation and storage.
- The current version of HYEBRID models the entire value chain of both the electricity and hydrogen sectors.
- In this report, iron powder is added as an energy carrier with production, import, transport and storage capacities. Also, the district heating sector is added with exogenous demand and endogenous generation capacities.

1: Exogenous variables are predefined inputs to the optimization model, while endogenous variables are determined within the model. The model covers techno-economic energy market fundamentals but abstracts from detailed technical generator and grid requirements. | 2: Variable renewables include solar PV, wind, and hydropower. | 3: Hydrogen import from outside and within the model region is constrained by import terminal and pipeline capacities; Iron import from outside and within the model region is unconstrained | 4: HYEBRID

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HYEBRID models the integrated decarbonization pathway from 2030 to 2045 for the majority of European countries

Input (check slides 47-51 for more info)

Demand
- Hourly electricity, hydrogen and district heating demand

Supply
- Existing (and possibly projected) generation capacities
- Investment, fixed operation and maintenance and variable costs
- Capacity factors and hydro inflows

Storage and decentral flexibilities
- Battery, hydrogen and iron storage potentials and costs
- EV-charging and heat pump flexibility

Infrastructure
- Net transfer capacities (NTCs) for electricity trade between countries
- Pipeline and ship-terminal infrastructure for iron and hydrogen imports and trade

HYEBRID

Linear optimization
(with perfect foresight)

Objective function
Cost-minimal demand coverage considering technical restrictions



Temporal resolution
Years: 2030, 2035, 2040, 2045
Granularity: 122 days x 24 hours[1]

Spatial resolution[2]
Model region of EU-27 excluding BG, MT, CY, RO, EL and including UK, CH and NO

Political framework conditions

Output

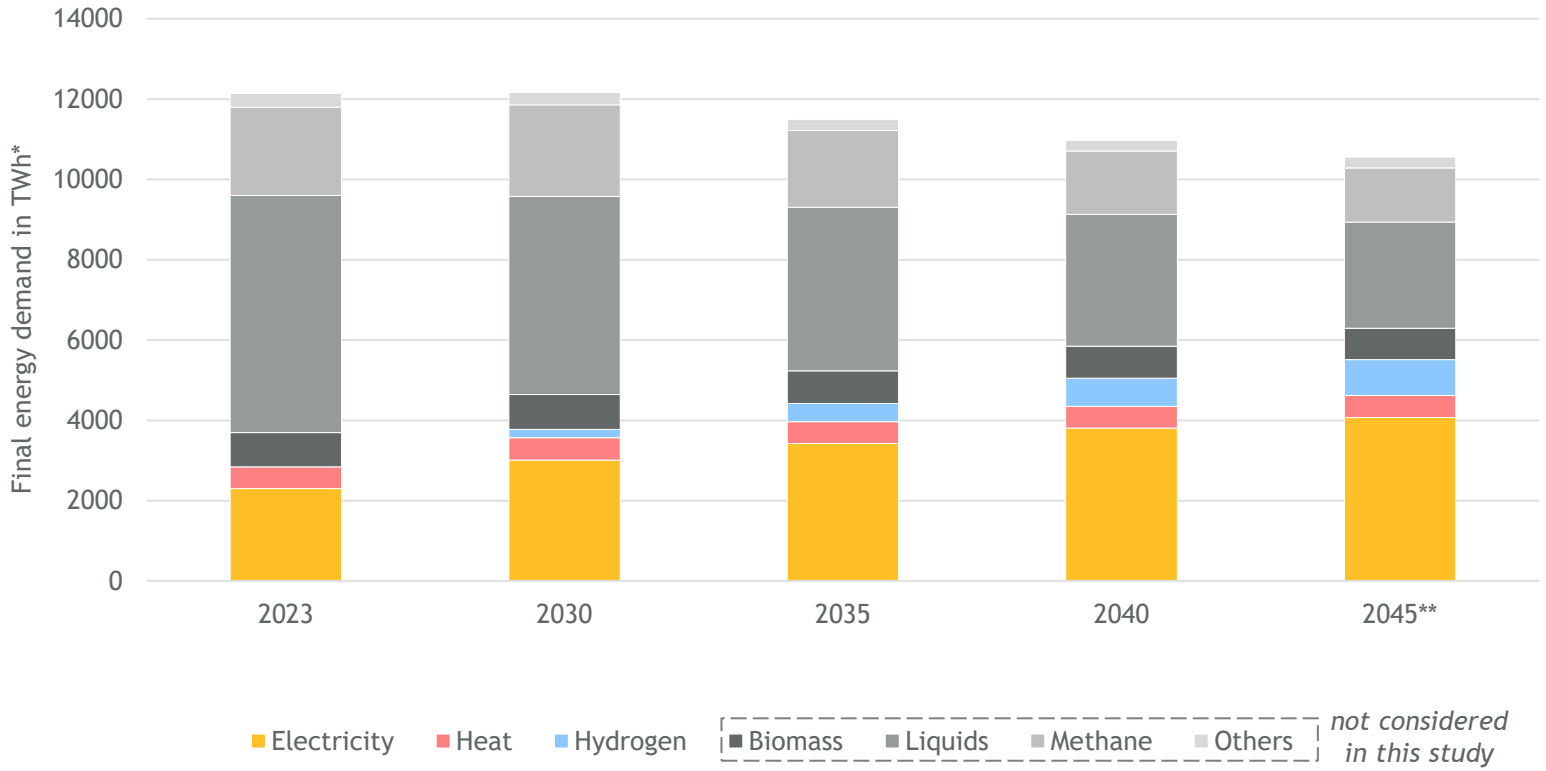
Investments
- Dispatchable plant capacity
- Electrolysis and iron reduction capacity
- District heat technology capacity
- Storage capacity
- Investment cost
- Operation and maintenance cost

Dispatch
- Supply mix (electricity and district heat)
- Local supply and imports (hydrogen and iron)
- Fuel use and costs
- Power trading
- GHG emissions
- Curtailment volumes

1: Typedays reduce modelling complexity. They are chosen based on the representativeness of their residual load and weighted accordingly. | 2: Each country is represented as one node in the model.

The *National Trends* scenario provides critical model assumptions on future European energy demand and supply

Final energy demand of the model region in the TYNDP 2026 National Trends Scenario[1]



Comments

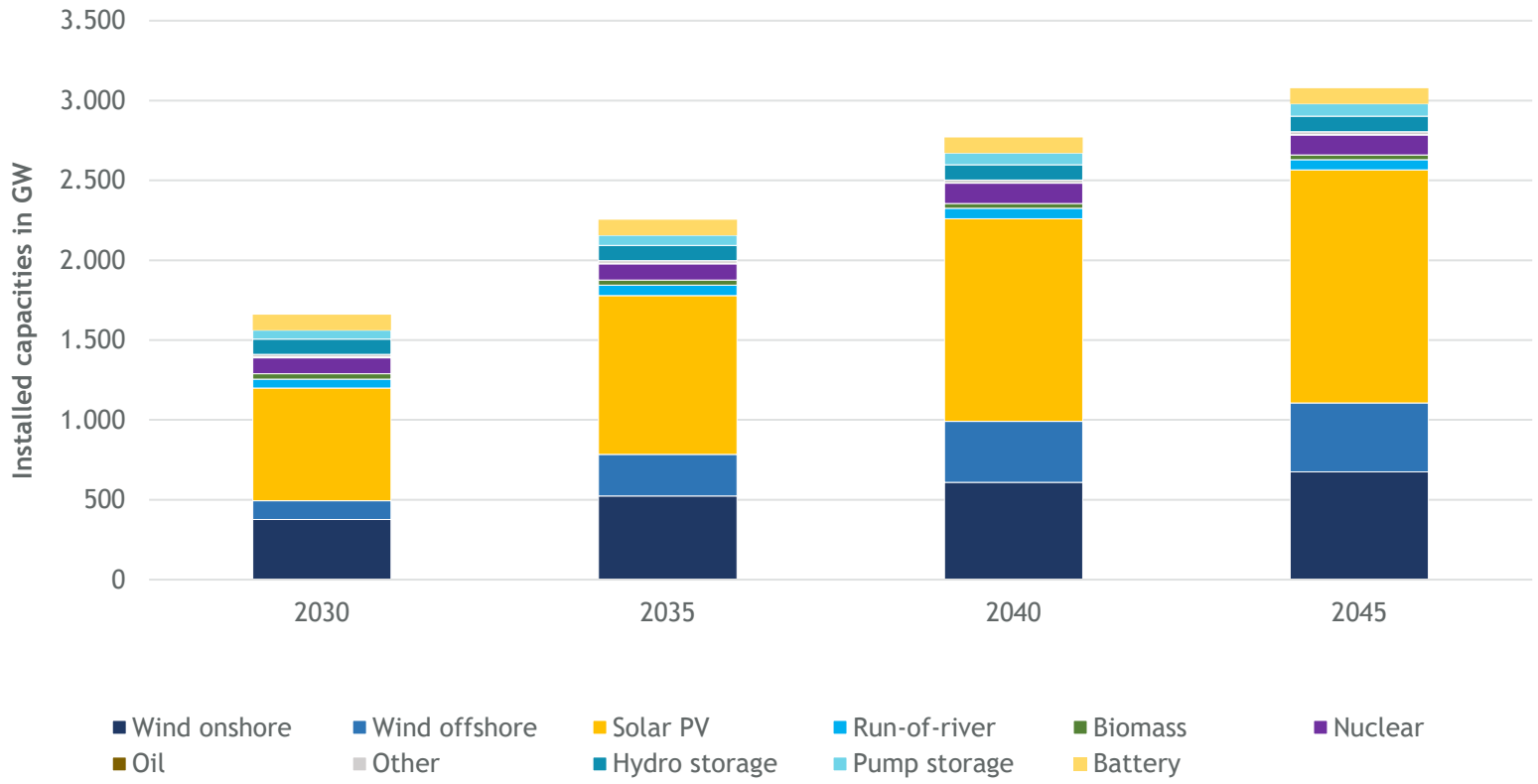
- The Ten-Year Network Development Plan (TYNDP) is the central European infrastructure report, identifying network needs against long-term scenarios. Its 2026 *National Trends* (NT) scenario reflects current national policies. As the bottom-up plans fall short of EU 2050 climate neutrality, a gap-filling mechanism closes the difference to an EU-wide pathway.[2]
- This analysis uses the *NT* scenario for country-level inputs. These include, among others, electricity, hydrogen and heat demands, generation capacities, weather years, cross-border transmission capacity or carbon budget.[3]
- This study excludes other final energy demands (e.g., liquids, methane or biomass), which fall from roughly 8,400 TWh_{th} in 2030 to 5,000 TWh_{th} in 2045.[4]

1: ENTSO-E (2026), ENTSO-E (2026) | 2: ENTSO-E (2025), ENTSO-E (2026) | 3: Electricity, hydrogen and heat demands constitute exogenous demands. Heat demand covers district heating and low-temperature industrial heat from heat networks; high-temperature process heat is captured under other final energy demands (e.g., hydrogen). Some generation capacities are set exogenously (see slide 48), others are optimized within this study.| 4: These other final energy demands are mainly used for industry processes, transport and space heating. | * TWh_{el} for electricity and TWh_{th} for all other energy carriers; In the following, TWh and GW denote electrical energy and capacity (TWh_{el} and GW_{el}), respectively. Thermal capacities are indicated separately with the suffix "th" | ** 2045 is linearly interpolated between 2040 and 2050.

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Renewable and nuclear capacities are fixed for all modelled years based on the *National Trends* scenario

Fixed capacities in the model region based on the TYNDP 2026 NT Scenario[1]



Comments

- Capacities in the TYNDP 2026 *National Trends* scenario represent national ambitions (e.g. Germany's Renewable Energy Act, EEG) as well as the gap-filling methodology to ensure net-zero emissions.
- In particular, VRE capacities are expected to increase significantly. PV capacity is assumed to more than double, offshore wind to more than triple and onshore wind to almost double between 2030 and 2045.
- Within this study, VRE, nuclear, oil and other (e.g. waste incineration) capacities are set exogenously according to the NT scenario. The analysis focuses on optimising decarbonised dispatchable generation from iron powder, hydrogen and gas plants with CCS.

1: ENTSO-E (2026) Visualisation Platform

We source the input data for hydrogen and iron powder based on scientific literature

Local Production

- Hydrogen may be produced via electrolysis within the model region. Related costs are based on the EWI Global Power-to-X Cost Tool[1].
- Iron powder production considers the reduction of iron oxide to iron using hydrogen and electricity. The water used for hydrogen production is released during the iron reduction and can be recycled.
- Central characteristics and assumptions on low-carbon iron production as well as its techno-economic parameters are based on IEA (2024), DNV (2024) and Vogl (2018). [2,3,4]
- Iron transport costs between countries in the model region are based on two reports on rail and inland shipping from the Federal Network Agency and DECHEMA.[5,6] Transport costs within a country are neglected.

Import

- Hydrogen import costs as well as transport costs within the model region are based on the EWI Global Power-to-X Cost Tool.[1]
- Iron powder import costs consider the production outside the model region and transport via shipping. Iron production costs are based on hydrogen production costs from the EWI Global Power-to-X Cost Tool[1] and costs of further processing.
- Production within and outside the model region share the same techno-economic parameters except for varying capacity factors and electricity prices within the model region and resource potentials, hydrogen cost, cost of capital and shipping distances in the case of imports.

Electricity and heat generation

- Investment costs for new iron power plants are assumed to be equal to new coal power plants. Iron power plants can also be retrofitted from existing coal power plants at reduced investment cost.[7]
- Iron power plants are modelled with an electrical efficiency 2% above that of hard coal power plants.[8]
- Other operational parameters are derived from the Danish Energy Agency and the ERAA-2025 dataset.[9,10]

1. EWI (2024): Global PtX-Cost-Tool, Costs are averaged across the six lowest-cost export countries. Using other electricity generation technologies like CSP could reduce import costs due to lower generation costs.
2: IEA (2024) | 3: DNV (2024) | 4: Vogl et al. (2018) | 5: Bundesnetzagentur (2024) | 6: DECHEMA (2025) | 7: Neumann et al. (2023) | 8: Schuler et al. (2025) | 9: Danish Energy Agency (2025) | 10: ERAA (2025)

We compare two scenarios and three sensitivities to investigate the influence of key assumptions

Investigated scenarios and sensitivities

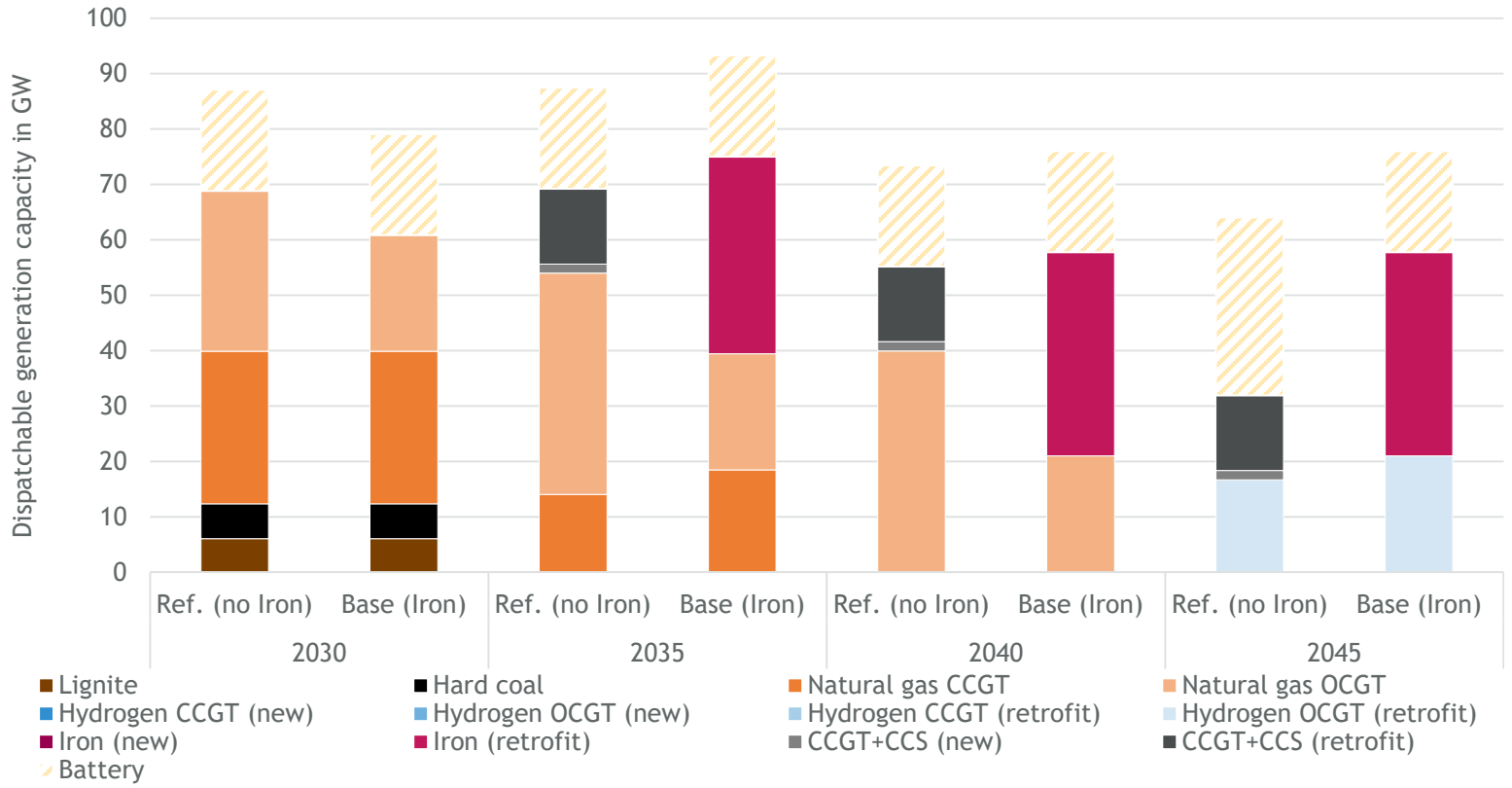
Scenario/ sensitivity	Investigated implementation challenge	Description
Reference (no Iron)	**Technology availability**	**Reference scenario based on the TYNDP 2026 with hydrogen and CCS available**
Base (Iron)	**Technology availability**	**Reference scenario with iron, hydrogen and CCS available**
Expensive Iron	Construction of infrastructure	Base scenario but with 50% increased cost for all components along the iron supply chain
Reduced VRE	Construction of infrastructure	25% reduced VRE capacity within the model region
Weather	Availability of energy	Different weather year chosen with other capacity factors for VRE as well as different demand due to colder temperatures

Comments

- We start with the *Reference (no Iron)* scenario based on the scenario framework from the Ten-Year Network Development Plan 2026 (TYNDP 2026). This reference scenario resembles the current planning for the European energy system.
- In the *Base (Iron)* scenario we add iron as available energy carrier to assess the impact of its availability.
- We then add three sensitivities based on the *Base (Iron)* scenario to investigate the influence of different input parameters.
- In the following we show the results of both the *Reference (no Iron)* and the *Base (Iron)* scenarios.

Iron power could be cost-competitive in the future German capacity mix

Endogenous dispatchable generation and storage capacities in Germany[1]



Comments

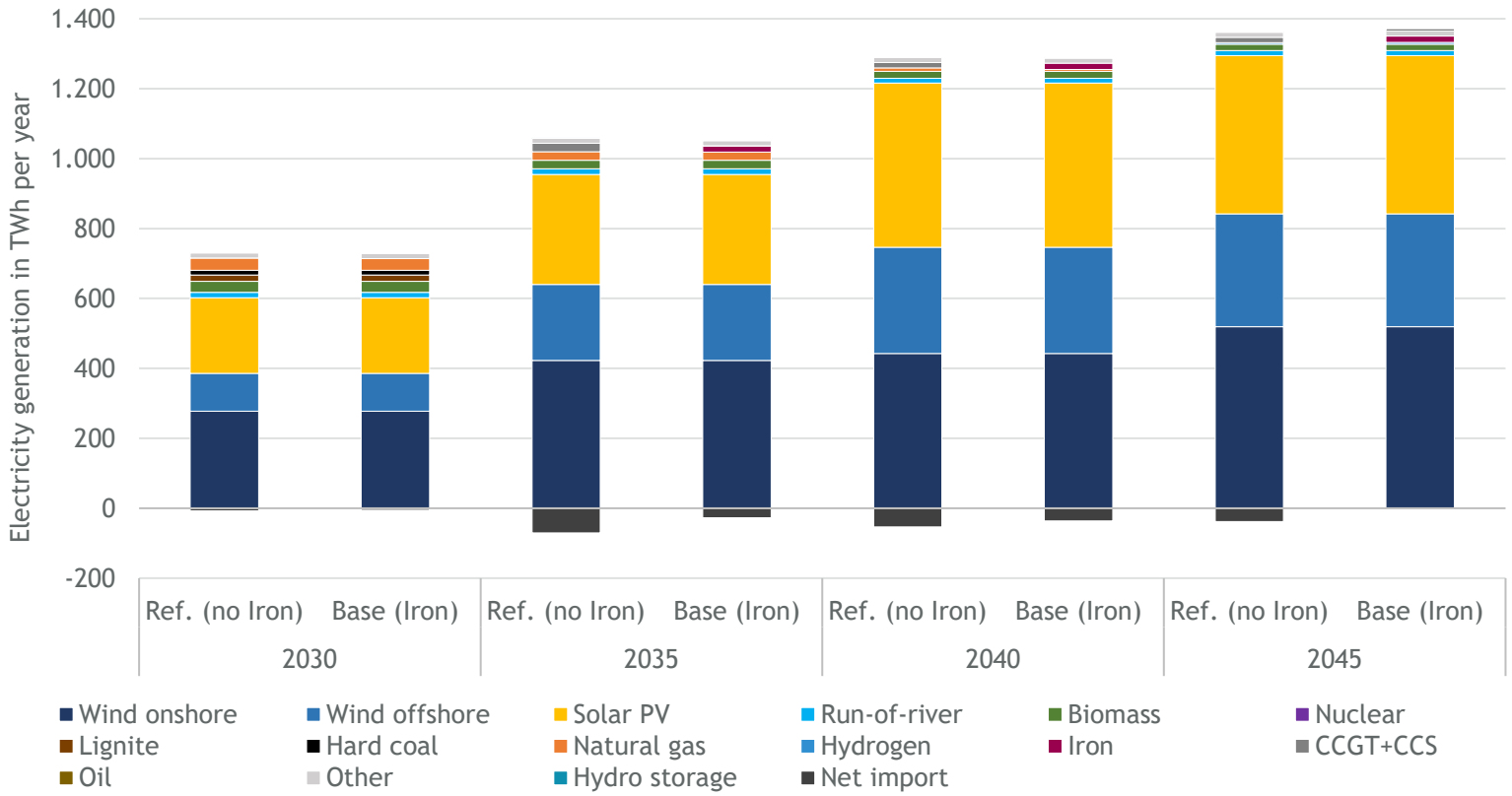
- Dispatchable generation capacity declines from around 70 GW in 2030 to roughly 32 GW (Ref.) and 58 GW (Base) by 2045, as the rising energy demand is overcompensated by VRE buildout.
- Natural gas generation progressively shifts toward OCGT peaker technologies, reflecting lower utilization and fewer full-load hours.
- In the Reference Scenario, 14 GW of CCGTs are retrofitted with CCS[1]. In the Base Scenario, all coal and lignite capacity (12 GW) plus 24 GW of capacity active in 2024 are retrofitted to iron.
- By 2045, remaining natural gas OCGT capacity is largely converted to hydrogen-fired OCGTs.
- Iron retrofits in the Base scenario partially substitute battery buildout and electricity imports in the Reference scenario.

1: In 2030, endogenous OCGT investment ensures model feasibility. Despite higher capacities in DE, model-region capacities are unchanged across scenarios. | 2: In the model, only CCGT can be retrofitted with CCS.

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With the assumed VRE capacities, the German electricity supply is dominated by variable renewable energies

Electricity supply in Germany

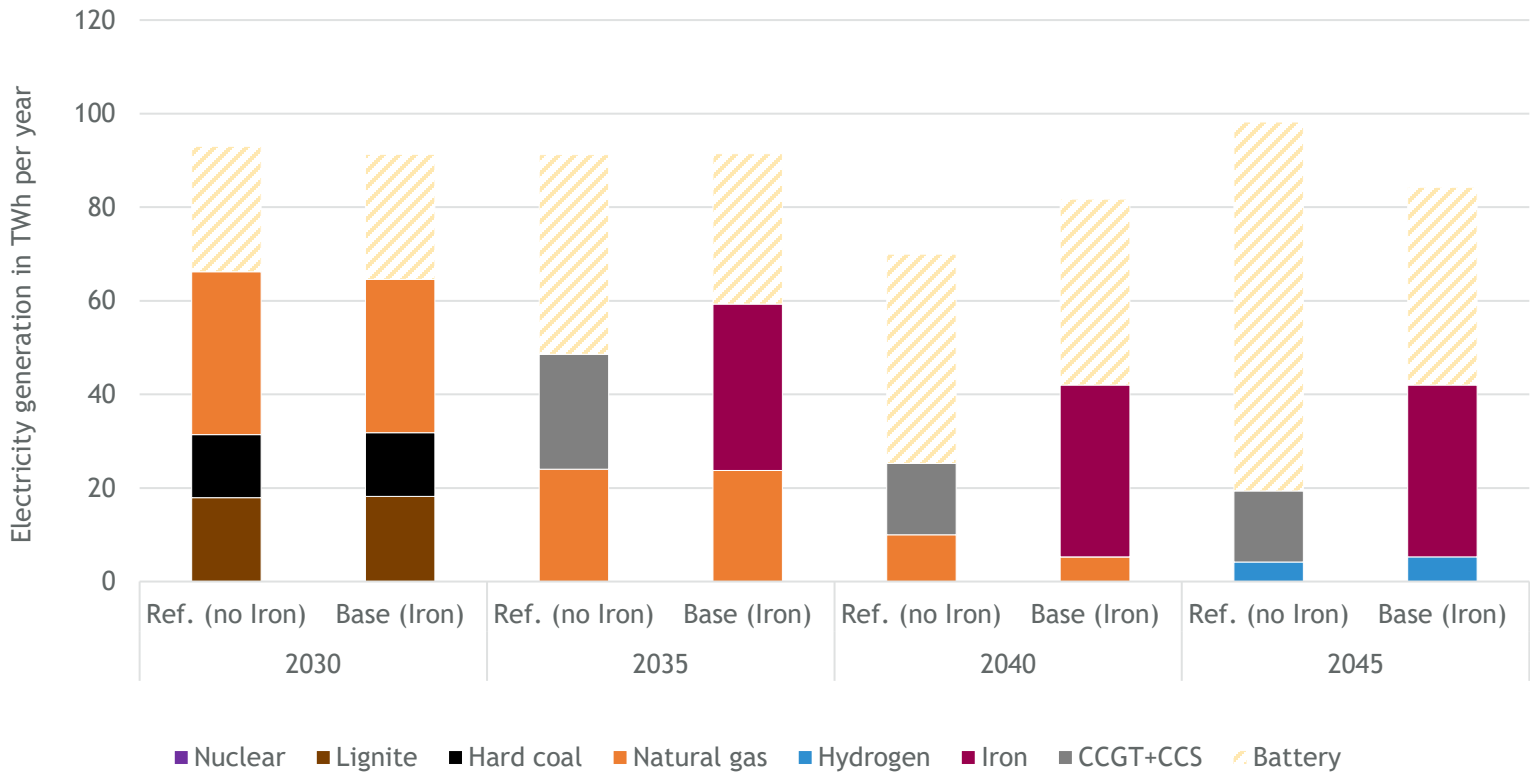


Comments

- In both scenarios, total generation increases from approximately 730 TWh in 2030 to around 1,350 TWh in 2045.
- VRE accounts for more than 90% of electricity generation by 2045, which limits the demand for dispatchable generation.
- Given their comparatively low operating costs, batteries, pump storage and demand flexibility supply most of the flexibility needed.
- Dispatchable generation technologies only have a minor effect on the supplied electricity and act mainly to provide firm capacity.
- Notably, Germany is a net-exporter of electricity in all modelled years except for 2045 in the Base scenario, with small net-imports of around 5 TWh.

Dispatchable electricity supply in Germany differs between the *Reference (no Iron)* and the *Base (Iron)* scenario

Dispatchable electricity supply of electricity generation and storage capacity

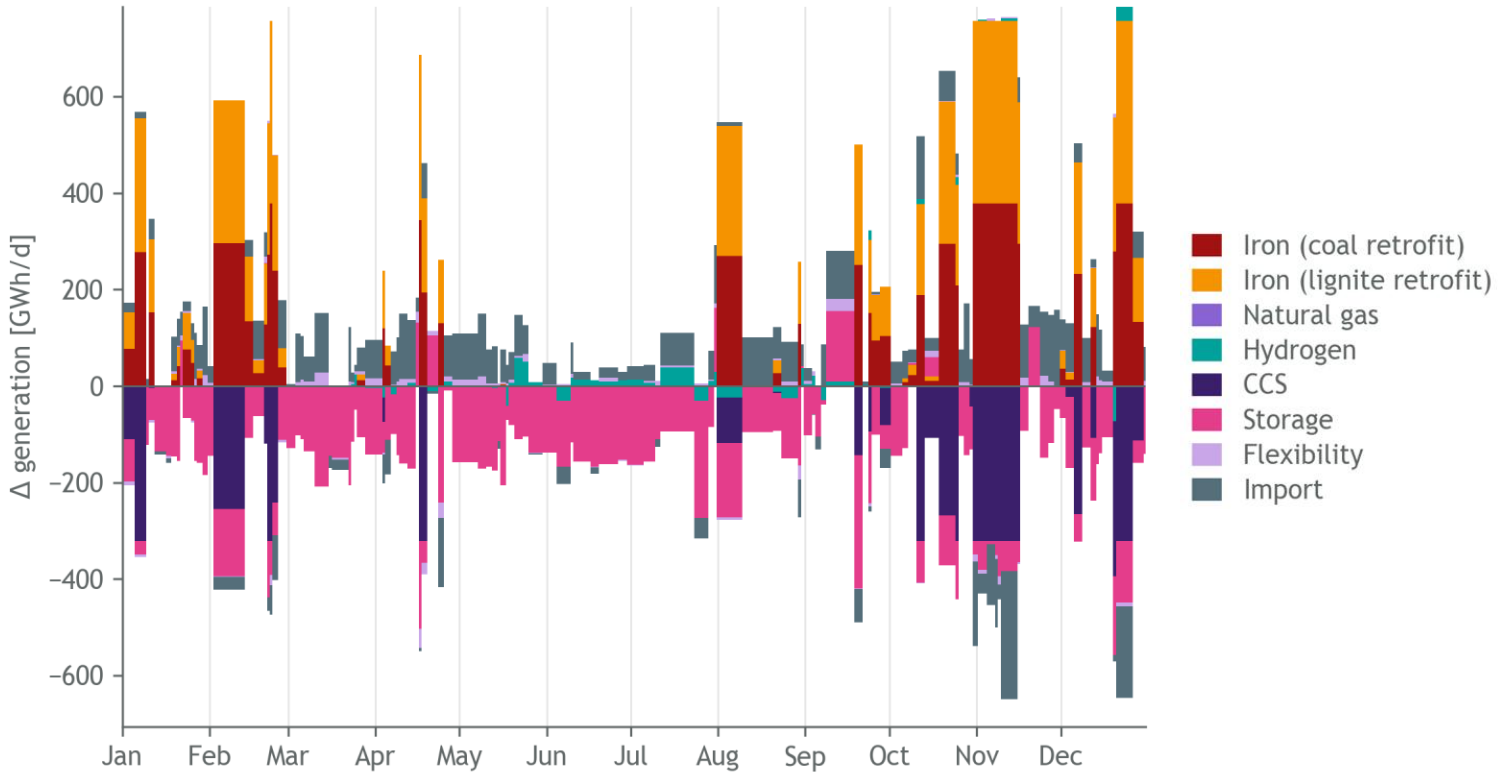


Comments

- In 2030, dispatchable generation is entirely supplied by natural gas, coal, and lignite in both scenarios.
- From 2035 onward, the generation mix diverges. The Reference scenario relies exclusively on natural gas (+ CCS), while the Base Scenario combines natural gas and iron, with iron effectively replacing CCS.
- By 2045, only decarbonized capacity remains in Germany, with hydrogen replacing the natural gas-based generation still remaining in 2040.
- Iron generation in the Base scenario replaces significant shares of battery storage utilization in the Reference scenario: the difference amounts to around 10 TWh in 2035, 17 TWh in 2040 and widens to almost 37 TWh in 2045, reflecting differences in dispatchable supply as well as imports and endogenous demand.

Iron acts as seasonal energy storage – it is used primarily in winter for electricity and heat generation

Difference in electricity generation between Base and Reference (2045, daily)



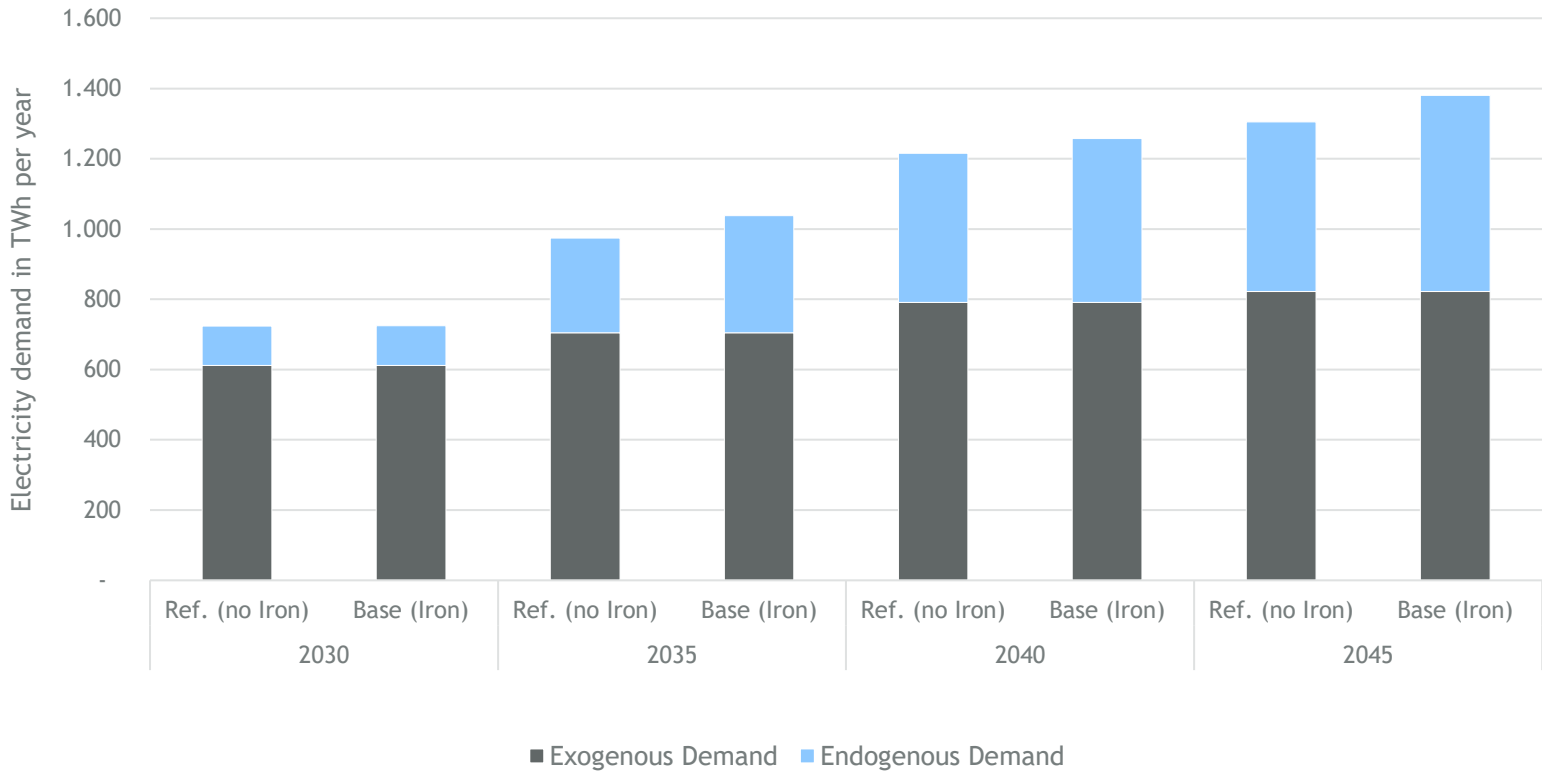
Comments

- Comparing electricity generation between the Base Scenario (with iron) and the Reference Scenario shows that iron displaces electricity generation from natural gas and CCS power plants, particularly during the winter months.
- During the summer months, some surplus renewable electricity is stored seasonally through iron reduction rather than in batteries, reflecting the cost-optimal combination of storage technologies.
- Regional electricity demand rises with additional electrolysis and iron reduction. Net exports are therefore lower than in the Reference scenario.
- Iron shifts electricity across seasons rather than across hours.
- Renewable generation itself remains unaffected by the availability of iron.

Storage entails batteries and hydropower dams.

German electricity demand in base is consistently higher than in reference scenario driven by hydrogen demand from iron reduction

Electricity demand in Germany

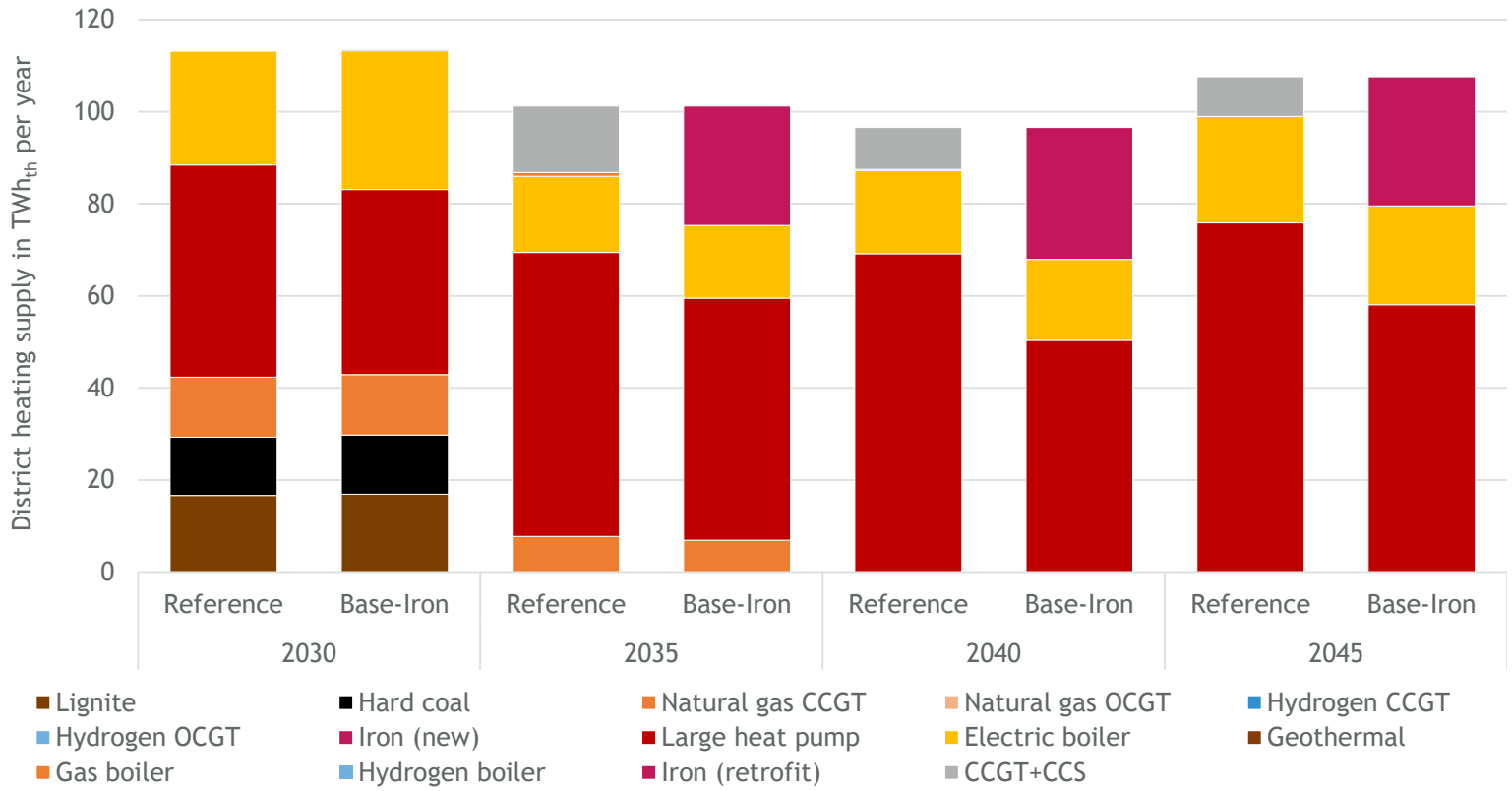


Comments

- Total electricity demand rises steadily across the projection horizon, increasing from roughly 730 TWh in 2030 to more than 1,300 TWh by 2045.
- Exogenous demand constitutes the larger share throughout, growing from about 600 TWh in 2030 to roughly 820 TWh in 2045, while endogenous demand expands more sharply, from around 110 TWh to around 480 TWh (Reference) and 560 TWh (Base).
- Demand levels in the *Base* scenario with iron surpass those of the *Reference* scenario in all model years after 2030. This is mainly due to the demands for local iron reduction using hydrogen.

Within the investigated scenarios, electricity-based heating dominates the future German district heat supply

District heat supply in Germany



Comments

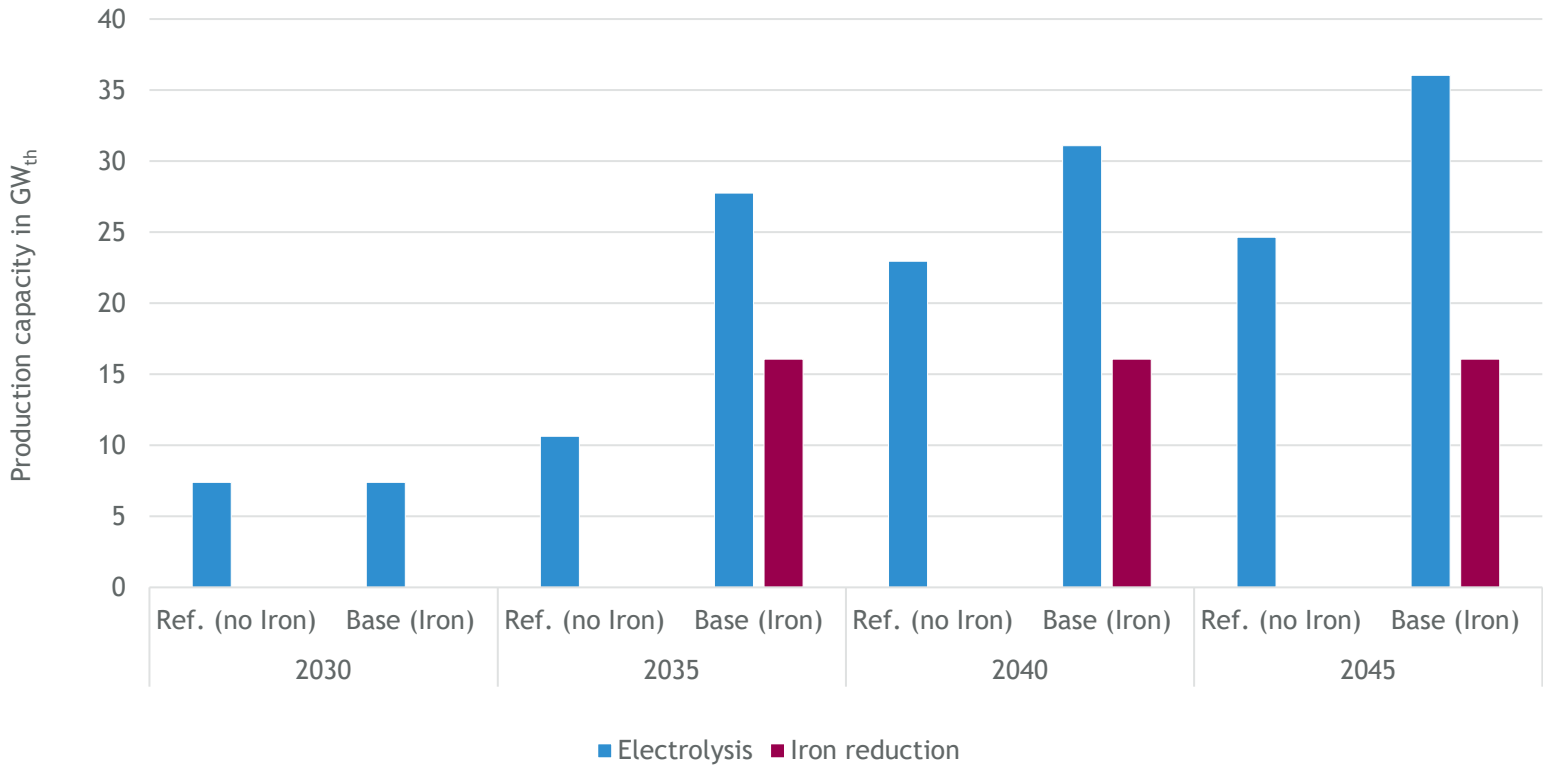
- District heating supply shifts sharply away from fossil fuels: lignite and hard coal disappear entirely after 2030, and natural gas CCGT declines steadily and phases out by 2040.
- Large heat pumps and power-to-heat emerge as the dominant supply technologies, together accounting for the majority of district heating supply over the entire model horizon.
- CCGT+CCS (*Reference* scenario) and iron retrofit CHP[1] (*Base* scenario) enter the mix from 2035, with iron retrofit CHP consistently contributing around 25% to the heating supply.
- Because iron CHPs cover a larger part of the heat load than CCGT+CCS, the *Reference* scenario requires higher heat pump capacities to compensate.

1: CHP refers to combined heat and power, i.e. plants that cogenerate electricity and heat.

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The deployment of significant electrolysis and iron reduction capacities drives electricity demand across scenarios

Hydrogen and iron production capacities in Germany



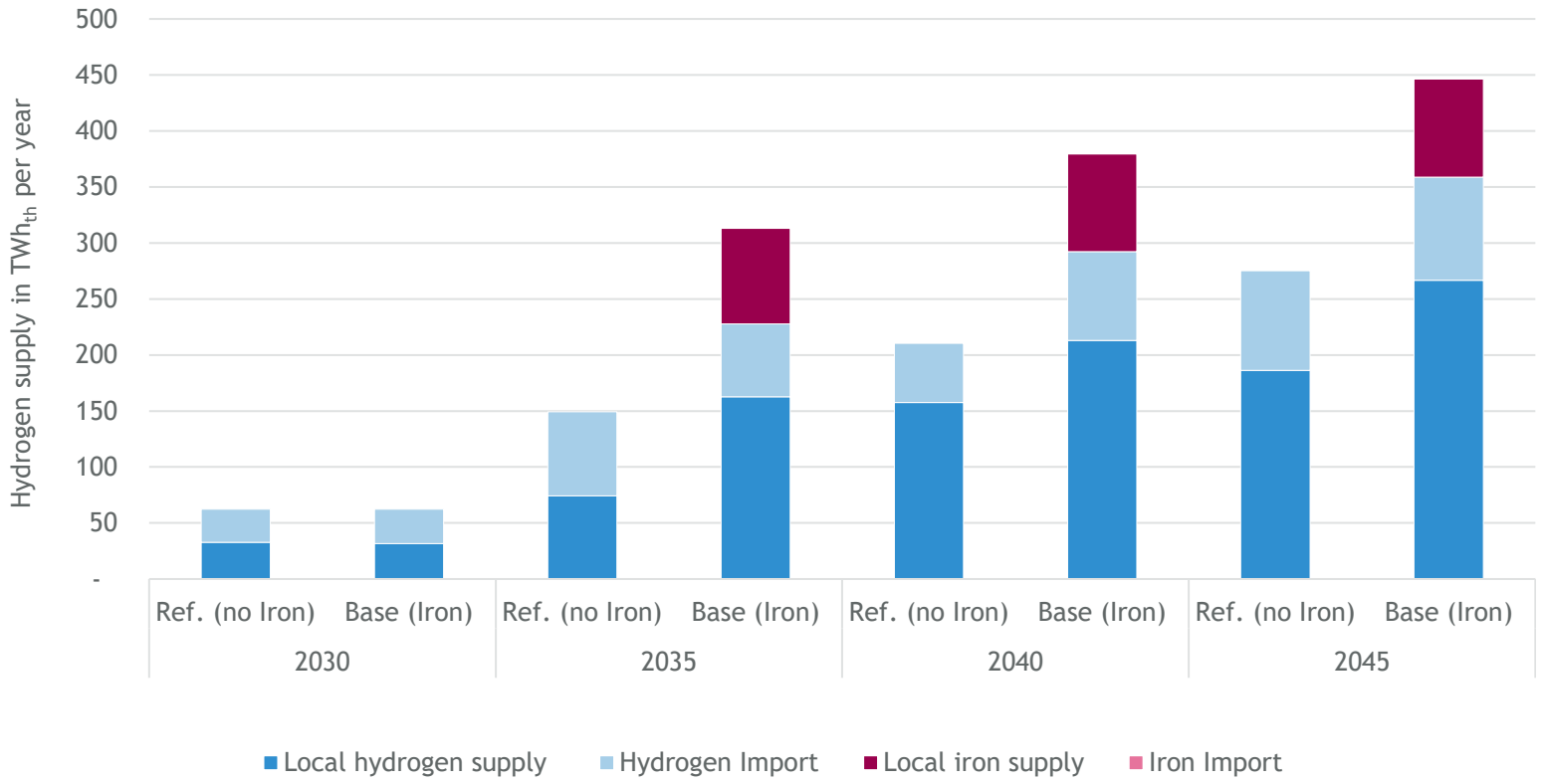
Comments

- In both scenarios, hydrogen production capacities increase steadily over the model horizon.
- Iron reduction capacities enter in 2035 and remain constant thereafter, reflected in a similar electricity demand from iron reduction plants across all model years.
- Both technologies achieve high full-load hours: around 5,300 to 5,500 h for iron reduction and rising from around 4,200 h in early years to over 7,000 h in later years for electrolysis in both scenarios.
- Electrolysis capacities are driven mainly by high exogenous hydrogen demand (see Slide 23). The Base scenario increase can be explained by higher hydrogen demand due to the endogenous hydrogen demand of the iron reduction.

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Local hydrogen supply increases continuously while imports remain broadly stable after 2035

Hydrogen and iron supply in Germany



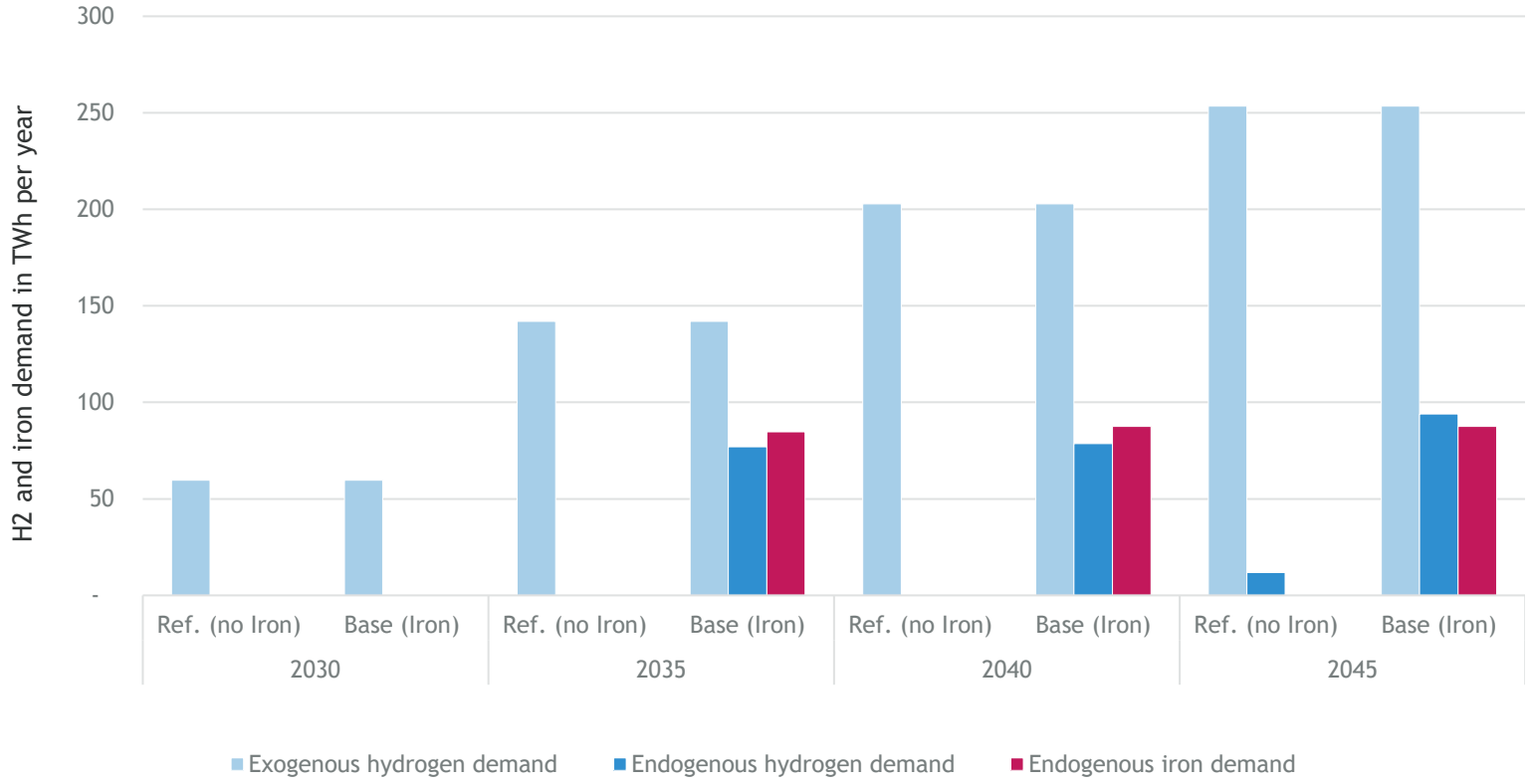
Comments

- Domestic hydrogen supply grows substantially over time, reflecting the attractiveness of local production given the abundant availability of renewable electricity in the underlying TYNDP NT scenario. A part of this supply is used to produce iron powder in the Base scenario.
- Iron powder is supplied entirely from domestic production with no imports. As with local hydrogen production, local iron reduction is also enabled by high VRE generation volumes.
- While hydrogen storage capacity is negligible in both scenarios, the model builds large quantities of iron storage and uses it as seasonal storage to increase the utilization of renewable electricity (see Slide 24).
- Hydrogen pipeline imports from neighbouring countries are a significant supply component providing flexibility for hydrogen supply.

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Iron reduction drives endogenous hydrogen demand in Germany

Endogenous and exogenous hydrogen and iron demands in Germany



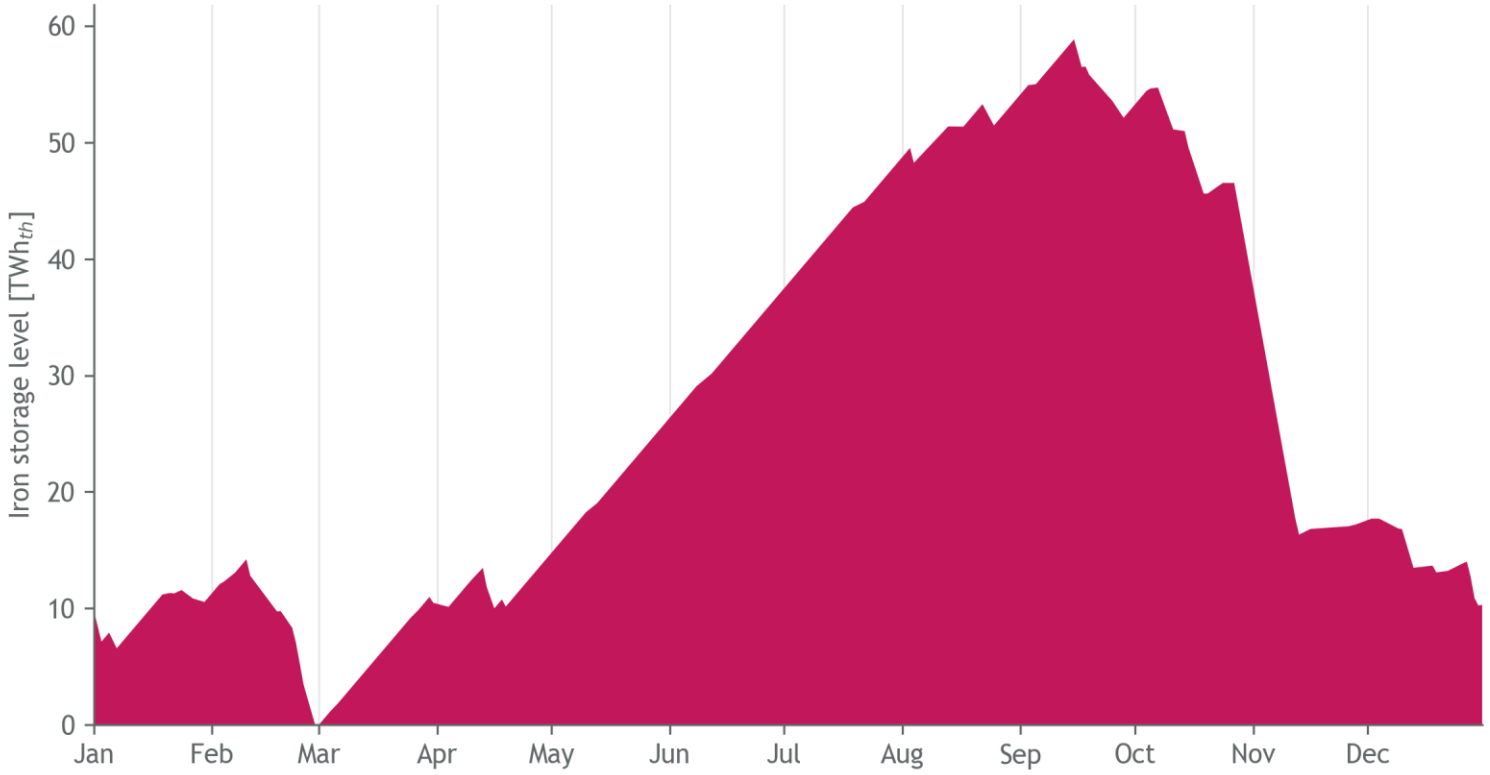
Comments

- Exogenous hydrogen demand rises from 60 TWh_{th} in 2030 to 250 TWh_{th} in 2045 and accounts for the majority of total demand throughout the horizon.
- Endogenous hydrogen demand emerges in 2035 in the *Base* scenario, rising gradually from 77 TWh_{th} to 94 TWh_{th} by 2045. It is used exclusively as an input for the iron reduction process until 2040.
- In the *Reference* scenario, hydrogen power plants are the only source of endogenous hydrogen demand (approx. 12 TWh_{th}) in 2045.
- By scenario definition, iron demand occurs only in the *Base* scenario, remaining stable at around 84 – 88 TWh_{th} across all model years.
- Notably, despite its comparatively low power-to-power efficiency, the usage of iron for re-electrification is cost efficient in these scenarios.

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Iron powder is used as a means of seasonal storage: during summer, the storage is filled, during winter it is emptied

Iron storage level in Germany in 2045



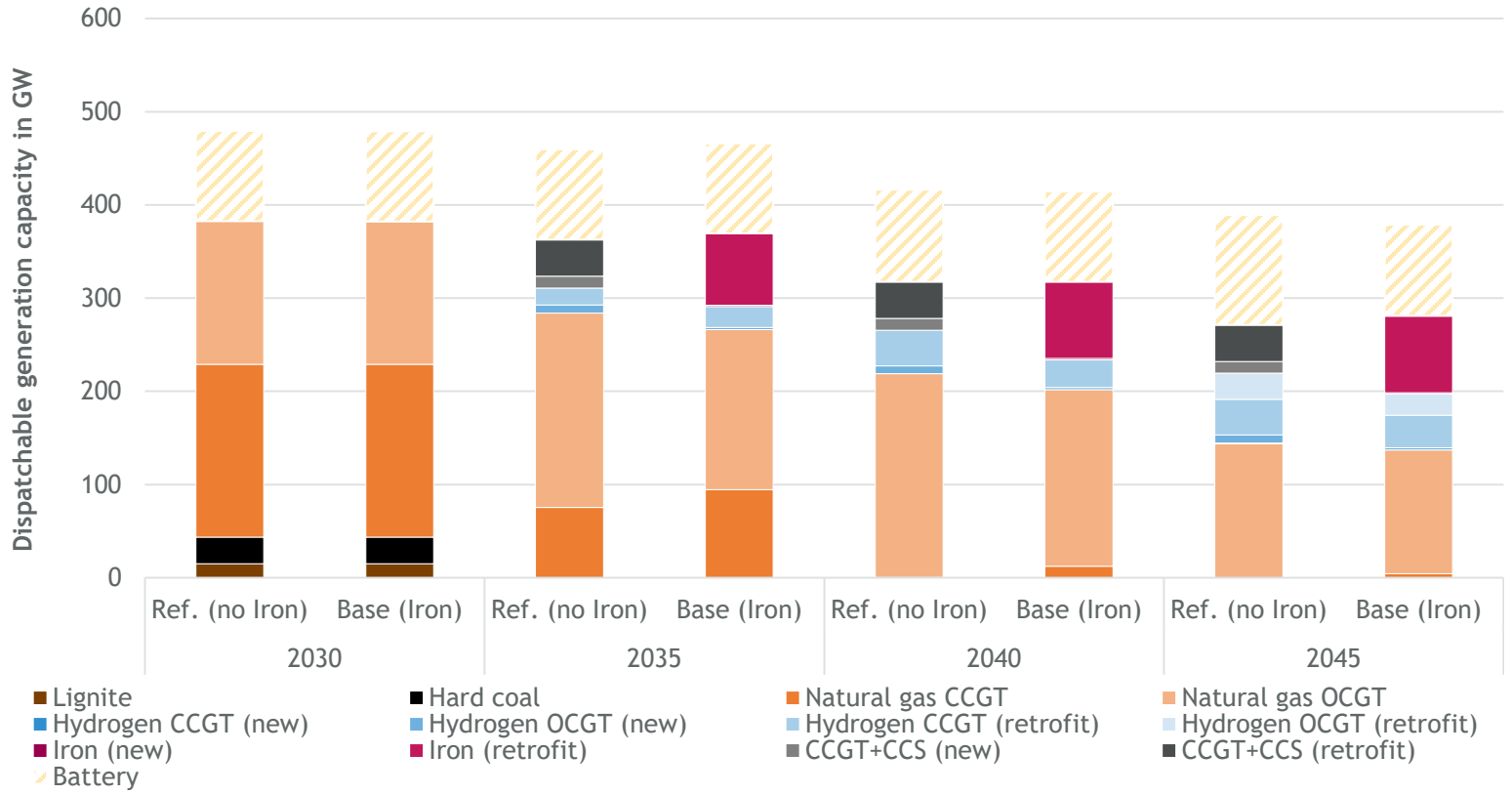
Comments

- The iron storage level in Germany follows a pronounced seasonal pattern: the storage is filled continuously from spring to early autumn and depleted during the winter months.
- The maximum storage level of about 58 TWh$_{th}$ is reached in September, after which the storage is drawn down rapidly in November.[1]
- A secondary filling and depletion cycle occurs in January and February, indicating that the storage is also used for shorter cold spells within the winter period.
- This indicates that iron powder can provide a relevant energy storage in 2045, as existing energy system scenarios commonly show reduced energy storage compared to current levels.[2]

1: The iron storage level lies in the order of magnitude of current German gas storage facilities | 2: EWI (2024)

Hydrogen plants play a larger role than iron across the model region – gas-fired OCGTs remain active in 2045 with CO_2 budget left

Endogenous dispatchable generation and storage capacities in the model region

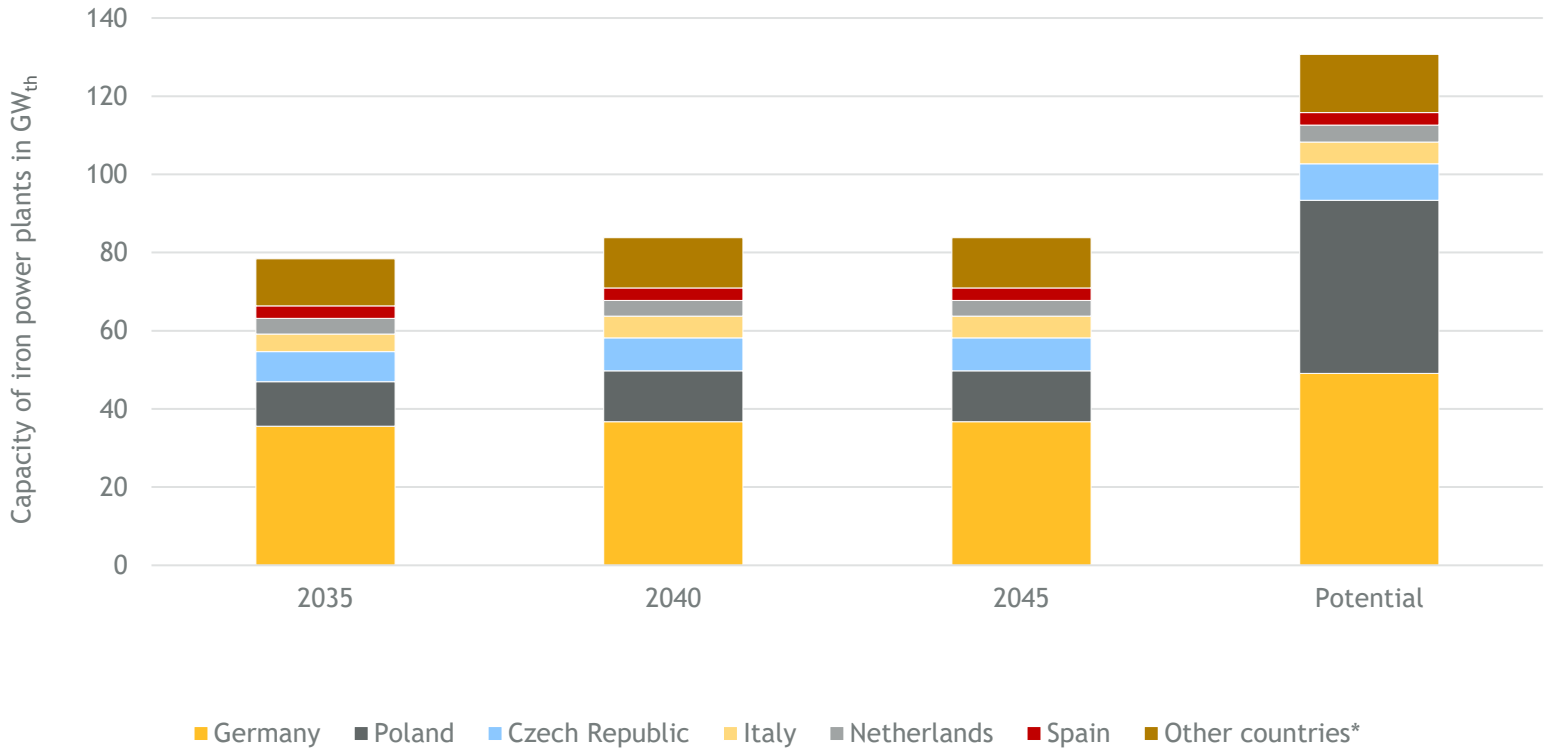


Comments

- Endogenous dispatchable generation capacity declines from around 380 GW in 2030 to roughly 270 GW (Reference) and 280 GW (Base) by 2045.
- As in Germany, natural gas generation progressively shifts toward OCGT peaker technologies, reflecting lower utilization and fewer full-load hours.
- However, decarbonization pathways differ: while iron and CCGT+CCS results from Germany are reflected in the model region's decarboni-zation pathway, hydrogen takes a more pronounced role in the region's capacity mix.
- Unlike in Germany, unabated natural gas OCGT capacity is not fully decommissioned or converted to hydrogen: around 130–145 GW remain in 2045, in line with the region-wide carbon budget.

Most countries with relevant potential switch to retrofitted iron

Iron capacity across the model region



Comments

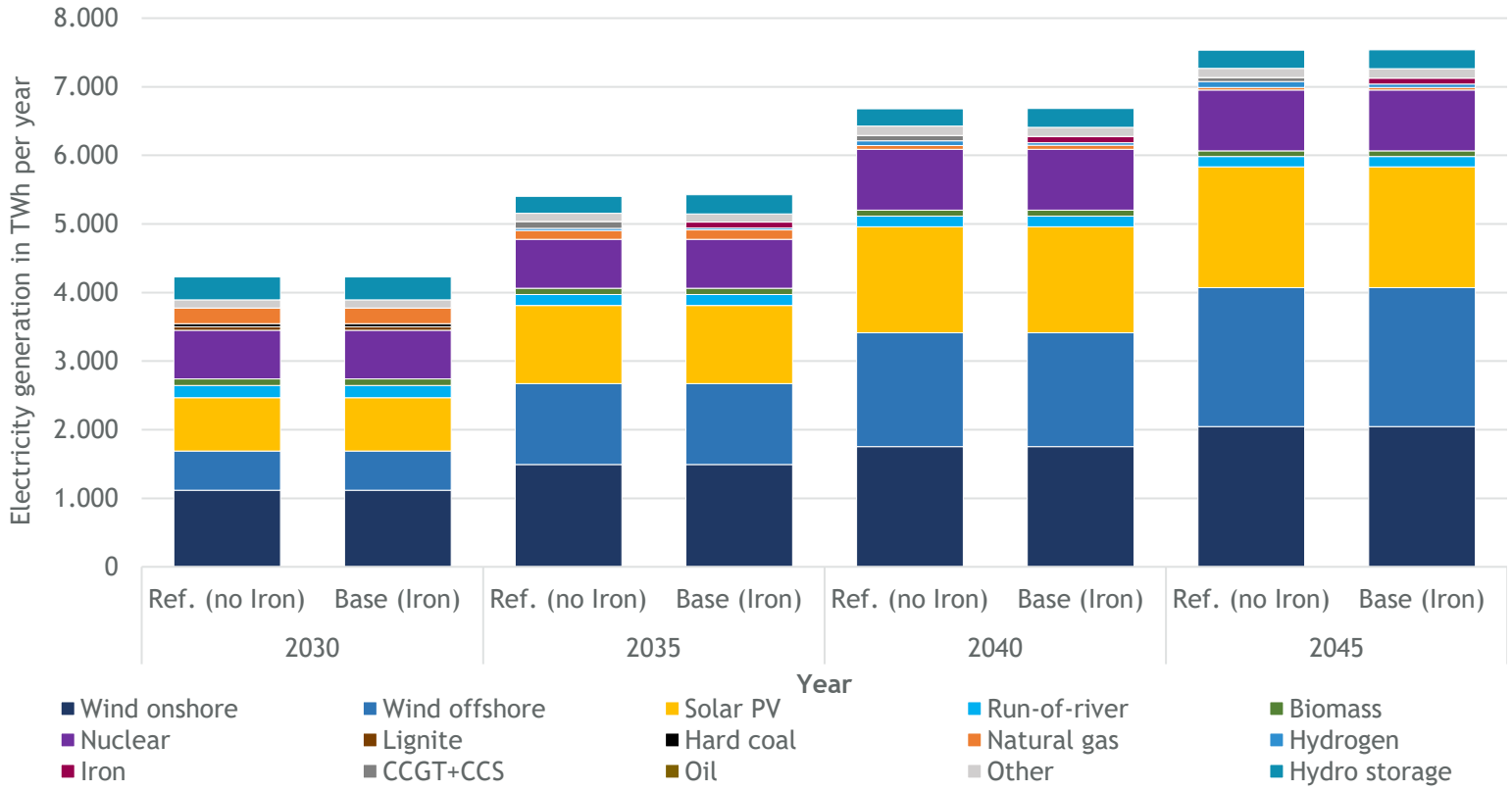
- Germany, Poland and the Czech Republic drive the buildout of iron power plants across the model region.
- Buildout is strongly linked to the available retrofit potential. While countries exploit most available retrofit sites, there is little buildout of new iron capacity.
- Most buildout happens in 2035 already, with some further capacity addition occurring in 2040.
- Germany's particularly high iron share in the capacity mix is thus partly a function of its large coal plant fleet available for retrofit.
- A second important driver is Germany's more stringent carbon budget compared to the region, prohibiting natural gas plants in 2045 already.

* Other countries include Austria, Belgium, Croatia, Denmark, Finland, France, Hungary, Ireland, Romania, Slovakia and Slovenia | Potential considers all existing coal power plants as available for retrofit irrespective of their planned decommissioning date

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In the model region, electricity supply is also dominated by renewables, with nuclear additionally adding a large amount

Electricity supply in the model region

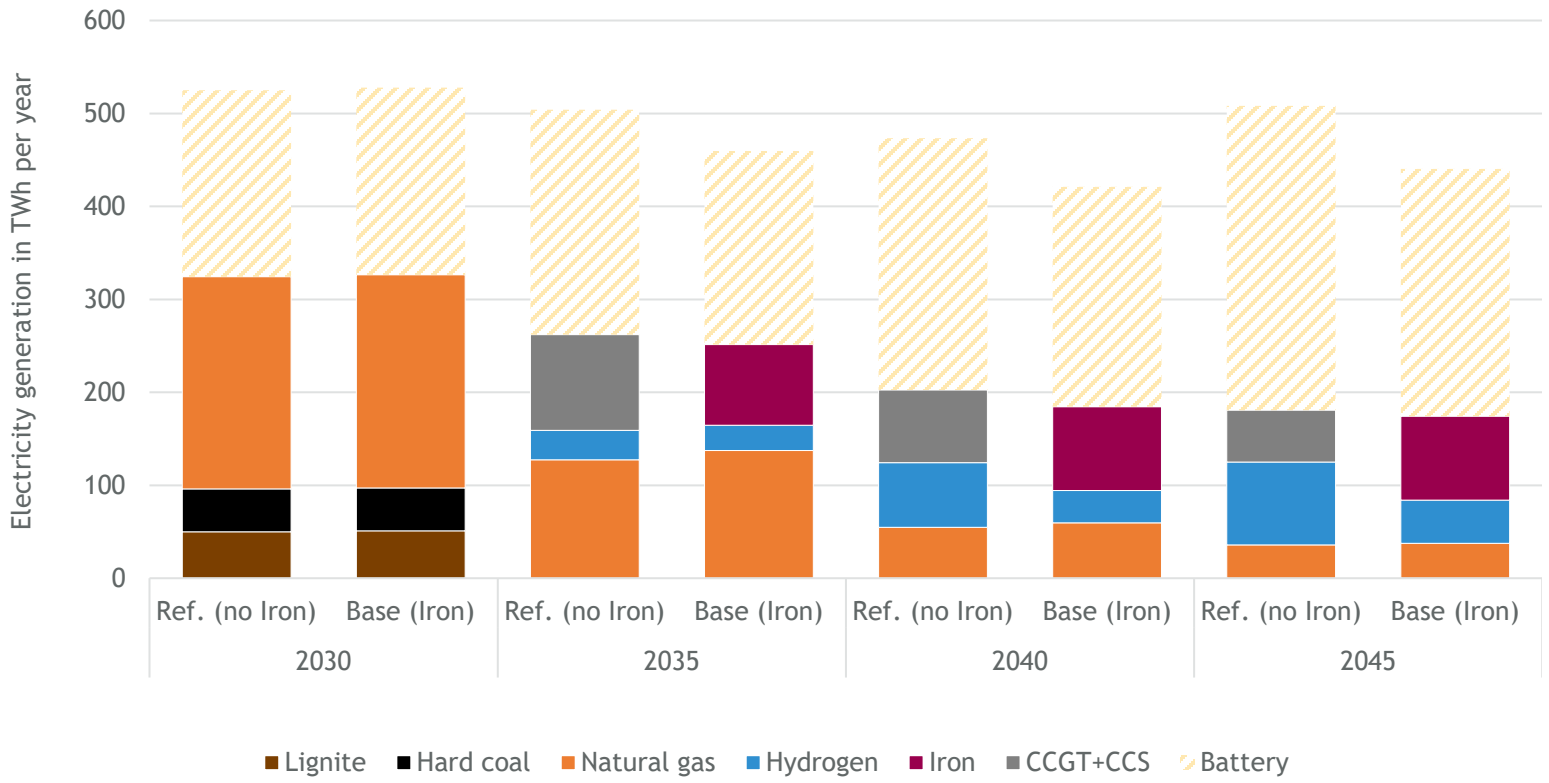


Comments

- In both scenarios, total generation increases from approximately 4,200 TWh in 2030 to around 7,500 TWh in 2045.
- VRE accounts for around 80% of generation by 2045. Together with nuclear, low-carbon sources cover more than 90%, limiting the demand for dispatchable capacity.
- Unlike in Germany, nuclear provides a firm low-carbon base, rising from about 710 TWh in 2030 to around 890 TWh by 2045 and remaining almost constant across both scenarios.
- Given their comparatively low operating costs, batteries and hydro storage supply most of the flexibility needed.

Iron replaces CCGT+CCS across the model region

Dispatchable el. supply of endogenous generation and storage capacities

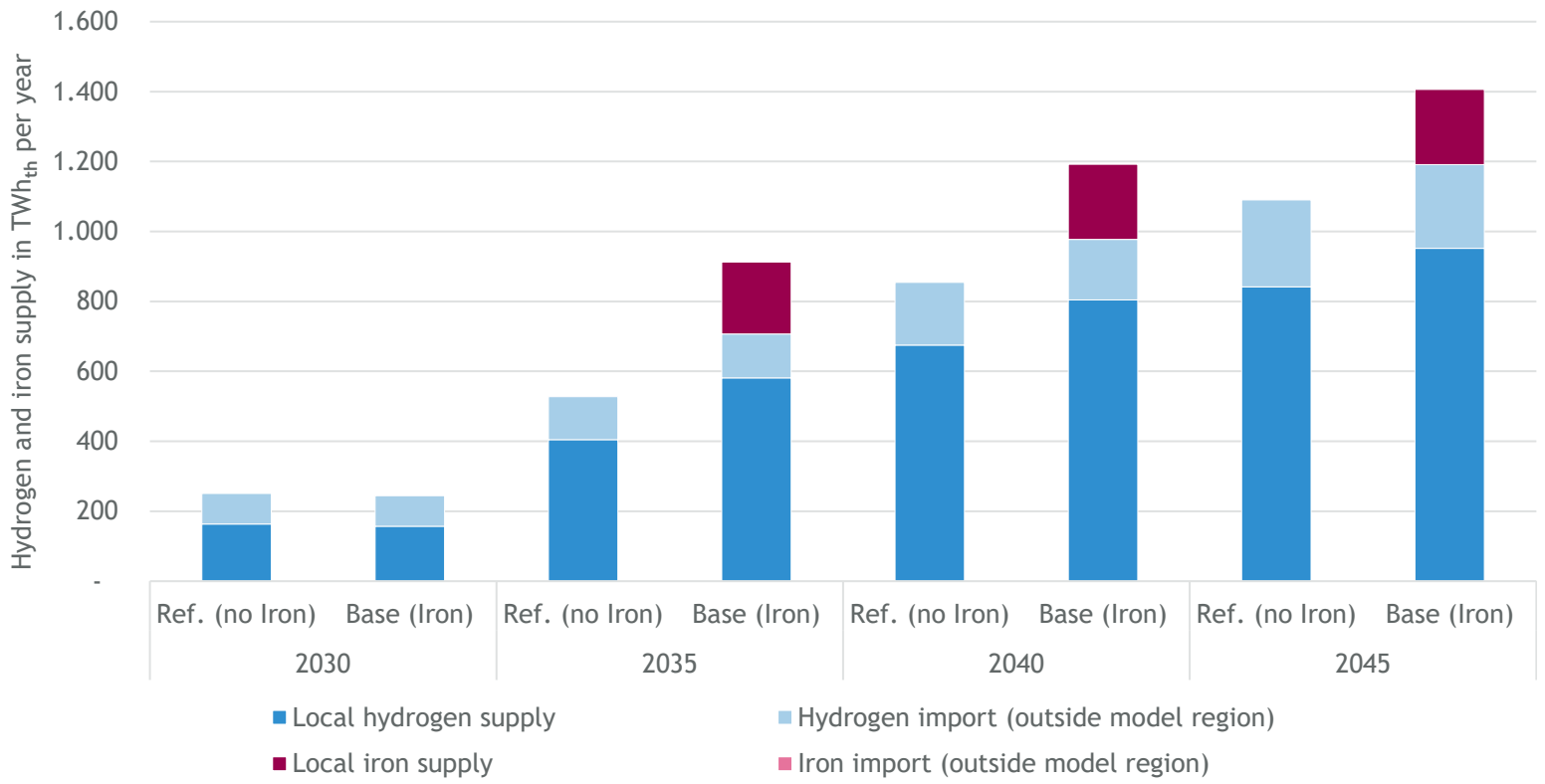


Comments

- Dispatchable generation declines from around 325 TWh in 2030 to roughly 180 TWh (Reference) and 175 TWh (Base) by 2045.
- In 2030, dispatchable generation is mainly supplied by natural gas (~228 TWh) as well as hard coal, and lignite in both scenarios.
- From 2035 onward, the mix diverges: the Reference scenario combines natural gas with CCGT+CCS and hydrogen, while the Base scenario combines natural gas with iron and hydrogen. Again, iron effectively replaces CCS.
- Hydrogen-based generation enters already in 2035 and expands to around 89 TWh (Reference) and 47 TWh (Base) by 2045.
- Unlike in Germany, unabated natural gas is not fully phased out. Around 36–37 TWh remain in 2045 in both scenarios, reflecting the region-wide CO_2 budget.
- With iron available, the model region can reduce its import dependence on natural gas and increase its energy self-sufficiency.

Supply for hydrogen and iron shows the same patterns in the model region as for Germany

Hydrogen and iron supply in the model region



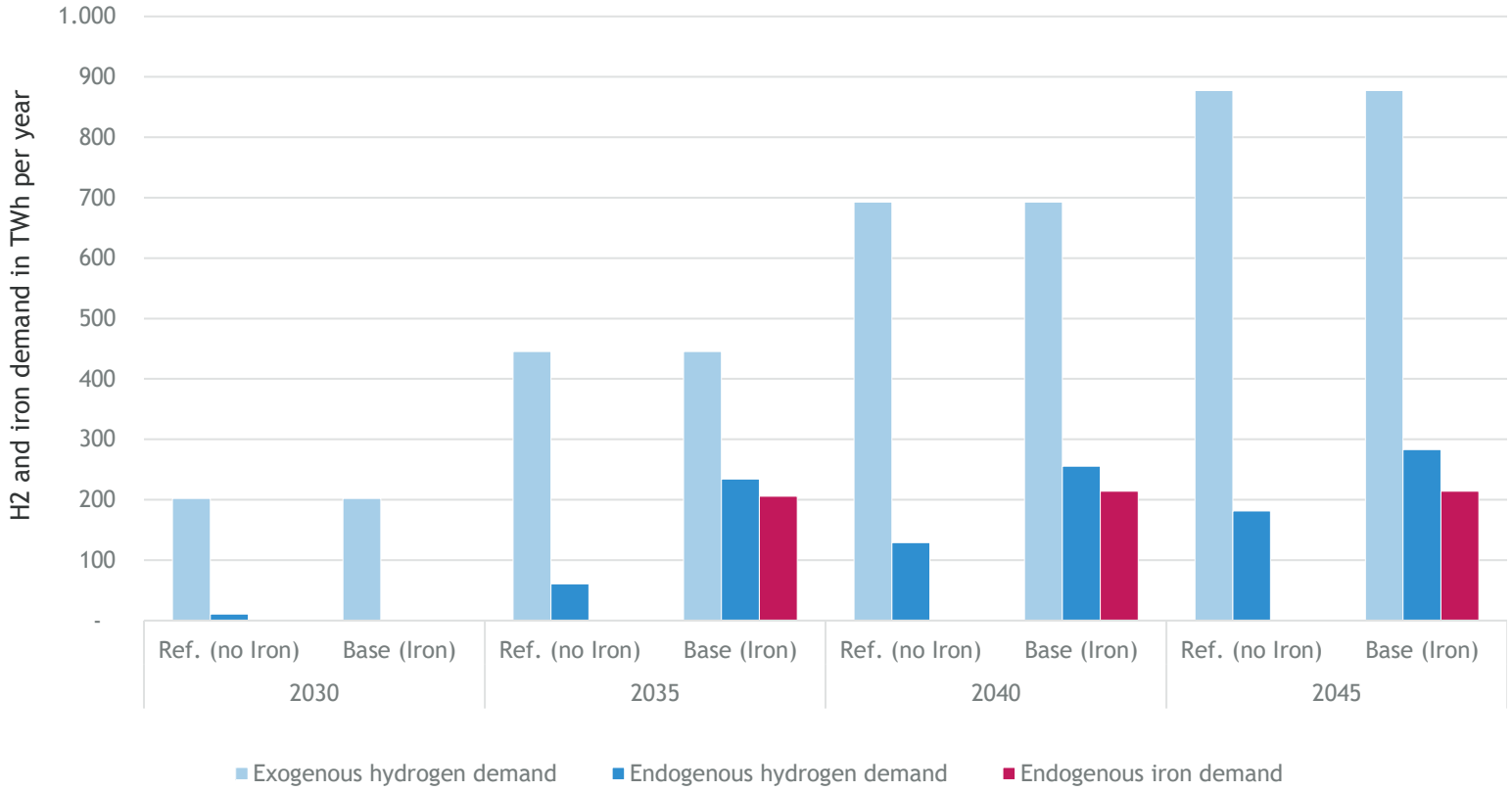
Comments

- Across the whole model region iron is produced fully domestically. Hydrogen also shows a high level of local production.
- Hydrogen imports into the model region are almost exclusively transported via the pre-defined pipeline routes. In both scenarios the pipelines are operated close to their minimum utilization of 80%.
- Once flexible hydrogen ship imports via the spot market are available in the year 2045, minor quantities are imported in countries with pre-defined terminal capacity.
- Gross hydrogen trade within the model region grows from around 130 TWh$_{th}$ (2030) to 400 TWh$_{th}$ in Ref. (no iron) and 500 TWh$_{th}$ in Base (iron) (2045).[1] In contrast, iron transport between countries remains much lower at 10 to 25 TWh$_{th}$.[1]

1: Gross trade is calculated as the sum of all cross-border flows rather than net balances.

Regional results for hydrogen and iron demand and supply also reflect results for Germany

Hydrogen and iron demands in the model region

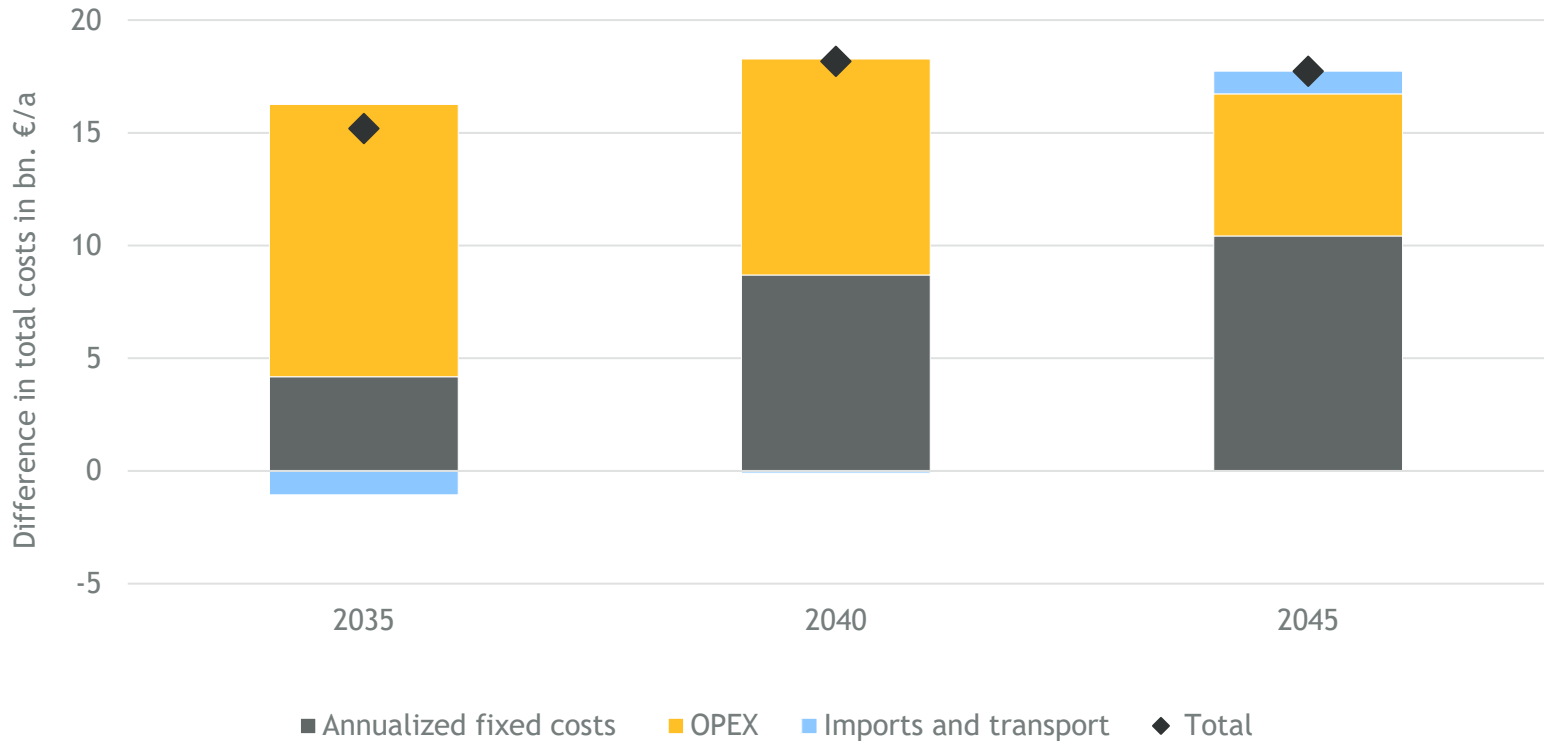


Comments

- As in the German case, exogenous hydrogen demand rises sharply, from around 202 TWh_{th} in 2030 to approximately 877 TWh_{th} in 2045. It is identical in both scenarios and accounts for most of the total demand throughout the horizon.
- The significant increase in hydrogen consumption in 2035 in both scenarios is due to hydrogen-fired power plants, which contrasts the German results.
- In the *Reference* scenario, endogenous hydrogen demand grows from around 60 TWh_{th} in 2035 to about 181 TWh_{th} in 2045.
- In the *Base* scenario, endogenous hydrogen demand rises from roughly 234 TWh_{th} in 2035 to 283 TWh_{th} by 2045, driven primarily by the iron reduction process. Iron demand itself stays broadly stable at around 205–215 TWh_{th} from 2035 onward.

The introduction of iron into the energy system could save 15 to 18 billion € annually across the model region

Annualized savings: Base Scenario (with Iron) vs. Reference Scenario (without Iron)



Comments

- As 2030 is set as the start year with most capacities being fixed, no significant differences emerge between the scenarios.
- However, from 2035 onward, iron delivers net savings that climb from around 15 bn €/a in 2035 to around 18 bn €/a in 2040 and 2045.
- OPEX is the main driver of the early savings (≈12 bn €/a in 2035), reflecting lower fuel and operating costs.
- Over time the driver shifts toward annualized fixed-cost savings, which grow steadily to around 10 bn €/a and become the largest contributor by 2045. In contrast, imports and transport play only a minor role.
- Savings in the Base Scenario with iron amount to around 13-14% of the modelled total system costs in the Reference Scenario.

Note: Total costs include annualized fixed costs for all endogenous investments in heat and electricity generation plants (see Slide 48) as well as storage and commodity production technologies, fixed operation and maintenance costs for all endogenous investments as well as lignite and coal power plants, import and transport costs for iron and hydrogen and fuel costs for all exogenously available fuels at a given price, such as natural gas. Additionally, CO_2-transport and -storage costs, costs for capturing residual emissions and load shedding costs are considered.

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Three sensitivities test whether iron's role holds under higher costs, less renewables and a colder year

Expensive Iron

- Similar as large-scale hydrogen-fired power plants or natural-gas-fired power plants with CCS, iron-fired power plants do not yet exist at scale and their costs are unclear. To check the robustness of the *Base (iron)* scenario, the cost along the iron supply chain is increased.
- With this sensitivity, the implementation challenge of infrastructure construction is addressed, as rising costs could be an obstacle in the build-up of the planned capacities.

➢ Import and technology costs of technologies associated with iron as an energy carrier are increased by 50%, while operating costs remain the same.

Reduced VRE capacity

- Reaching the planned net-zero VRE capacity is not guaranteed, as it depends on the continuous expansion of both grid infrastructure and VRE installations. To account for potential delays in this expansion, a constrained build-out scenario is examined.
- This sensitivity reflects implementation challenges associated with scaling up VRE capacity, which may slow the expansion of planned installations

➢ Capacities of solar PV, onshore wind, and offshore wind are reduced by 25% across the entire model region and time horizon.

Uncertain weather conditions

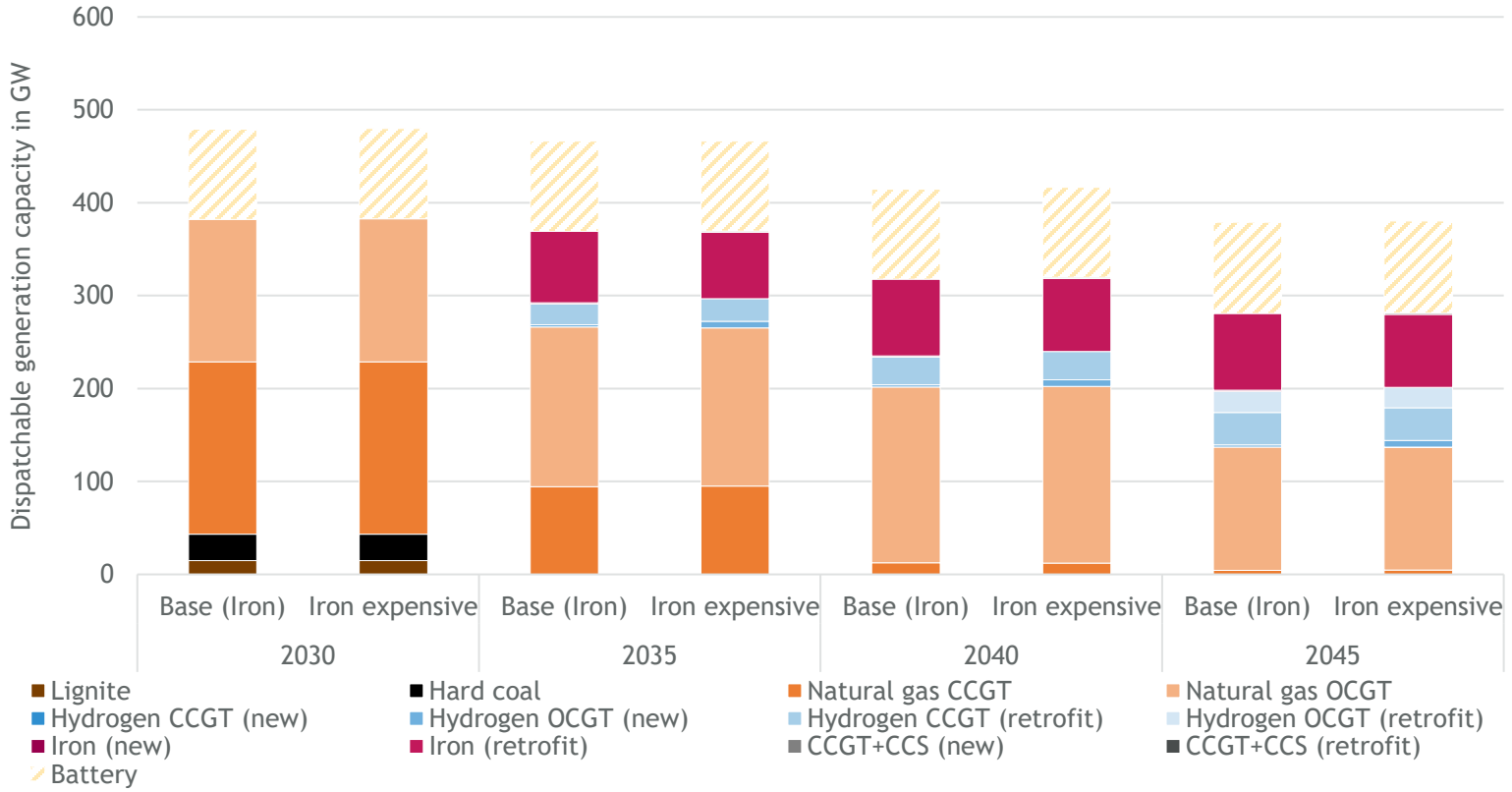
- A decarbonized energy system is sensitive to VRE generation and demand. These factors are shaped by the assumed weather year. Rerunning the analysis with a different weather year reveals how robust the results are.
- With this sensitivity, the implementation challenge of availability of energy is addressed, as the weather year changes VRE generation potentials as well as demand.

➢ The historical weather year 1997 is used instead of the representative TYNDP 2026 weather projections. This year represents a colder year[1] with lower PV and offshore wind full load hours.

1: The lower temperature level of 1997 leads to higher demands for heating and lower demands for cooling.

Higher iron retrofit costs barely affect technology choice – capacity mix is insensitive to 50% higher investment cost

Endogenous dispatchable generation and storage capacities in the model region

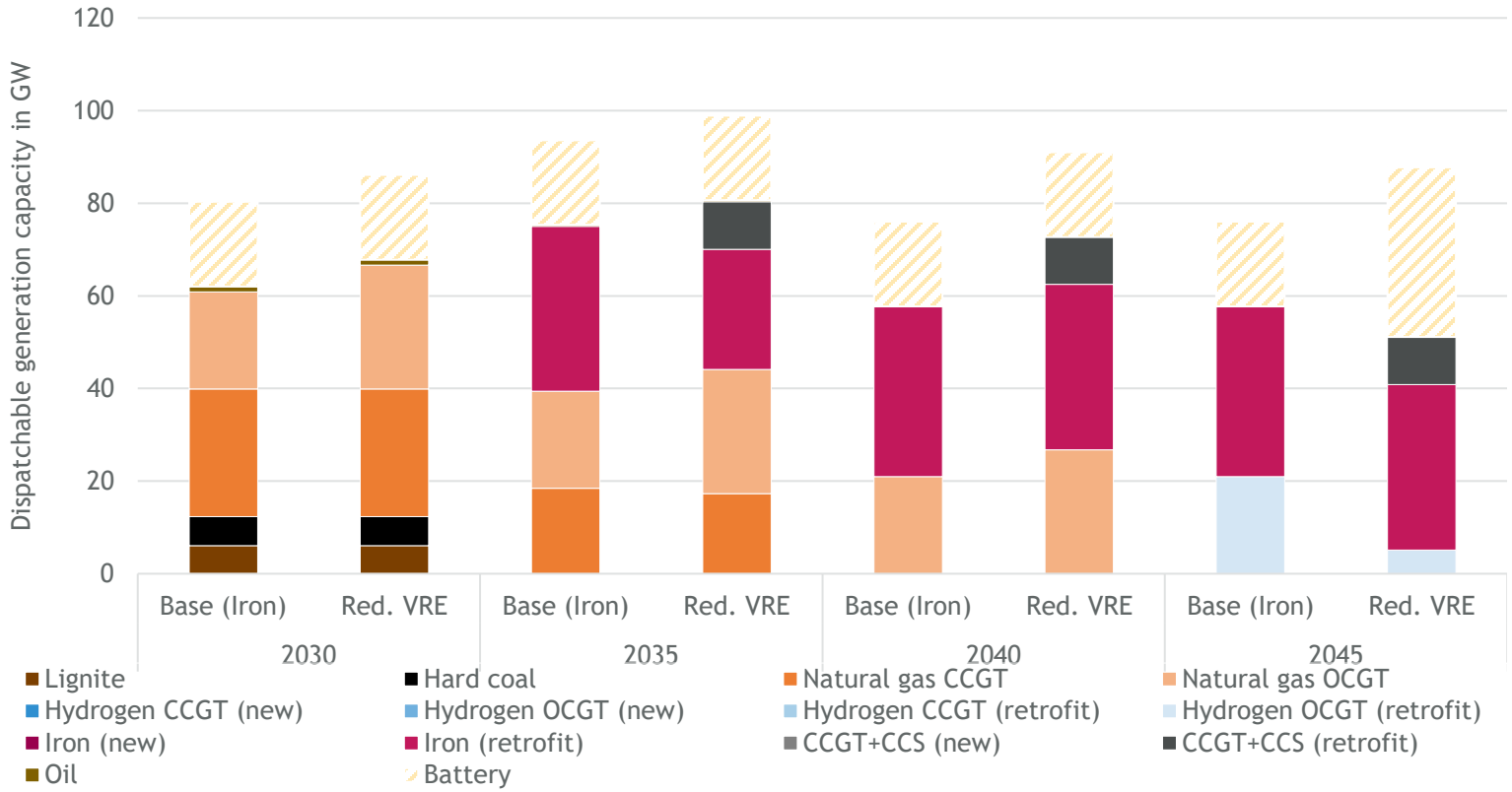


Comments

- Increasing iron costs by 50% has only a limited impact on the results, indicating a robust role of iron: retrofitted iron capacity decreases only slightly (78 vs. 83 GW from 2040 onward), with no new iron plants being built.
- In 2045, total hydrogen capacity is around 5 GW higher than in the *Base* scenario (65 vs. 60 GW), mainly due to additional new hydrogen OCGTs. CCGT+CCS retrofits emerge only at a negligible scale (approx. 1 GW).
- In Germany, there is no visible difference in generation capacities and generation between the two scenarios.
- Across the model region, iron-based electricity generation is reduced by around 10% over the time horizon and cost savings decrease towards 10 to 13 bn. € compared to the reference scenario.

With reduced VRE, more natural gas capacity is retained, and CCGT+CCS retrofits partly substitute iron and hydrogen

Endogenous dispatchable generation and storage capacities in Germany



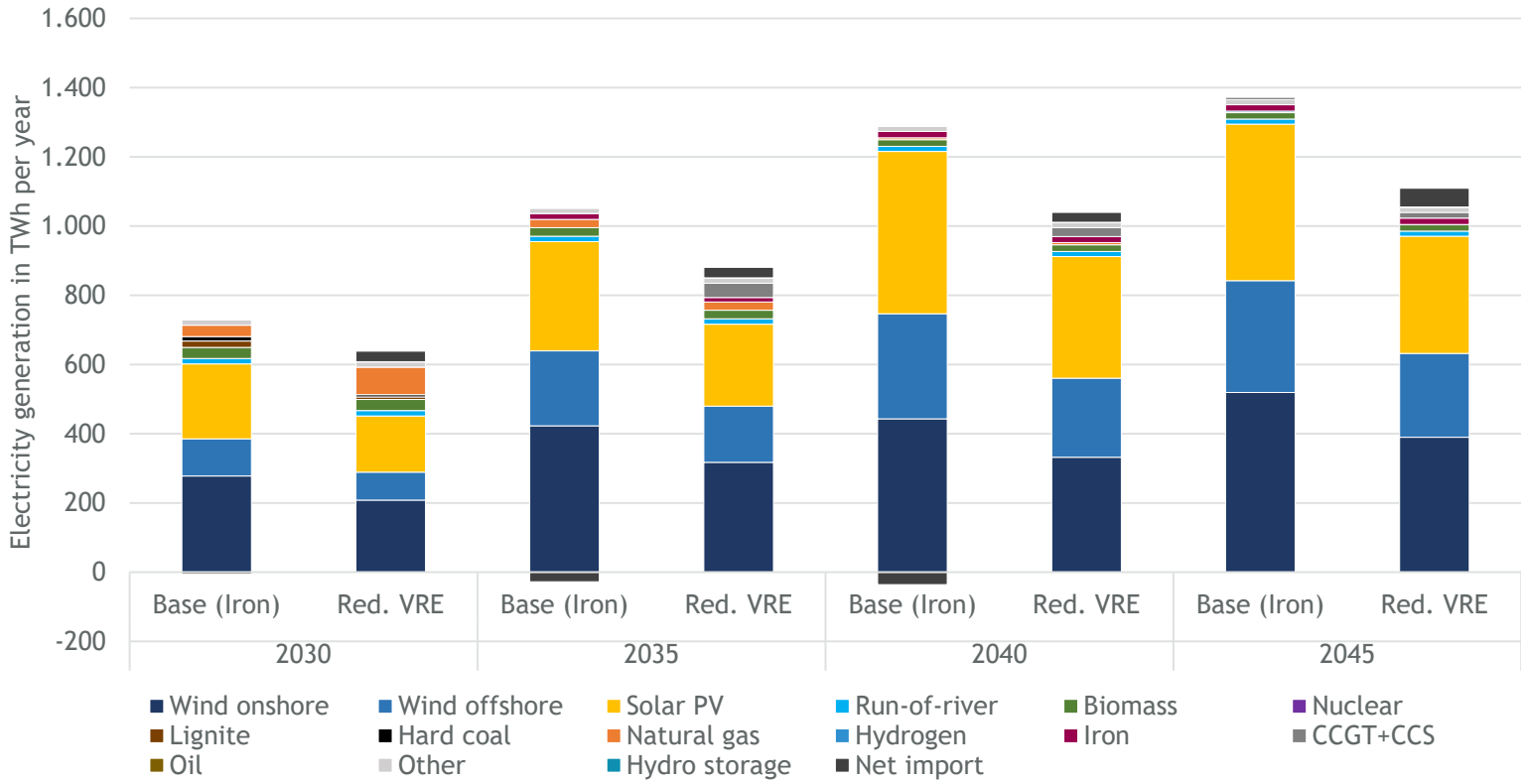
Comments

- When VRE capacity is reduced, the demand for dispatchable capacity increases: around 6 GW of additional natural gas OCGT capacity (27 vs. 21 GW) is kept in the system from 2030 to 2040.
- In 2035, fewer coal and lignite plants are retrofitted to iron than in the Base Scenario (26 vs. 36 GW); instead, around 10 GW of CCGT capacity is retrofitted with CCS.
- While iron retrofit capacities in the long term are almost identical in both scenarios (36 vs. 37 GW), hydrogen retrofits are substantially reduced (5 vs. 21 GW in 2045) and replaced by CCGT+CCS.
- This reflects higher hydrogen production costs, as less low-cost VRE electricity is available for electrolysis.

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Reduced VRE capacity lowers both VRE generation and electricity demand – Germany shifts from net exporter to net importer

Electricity supply in Germany



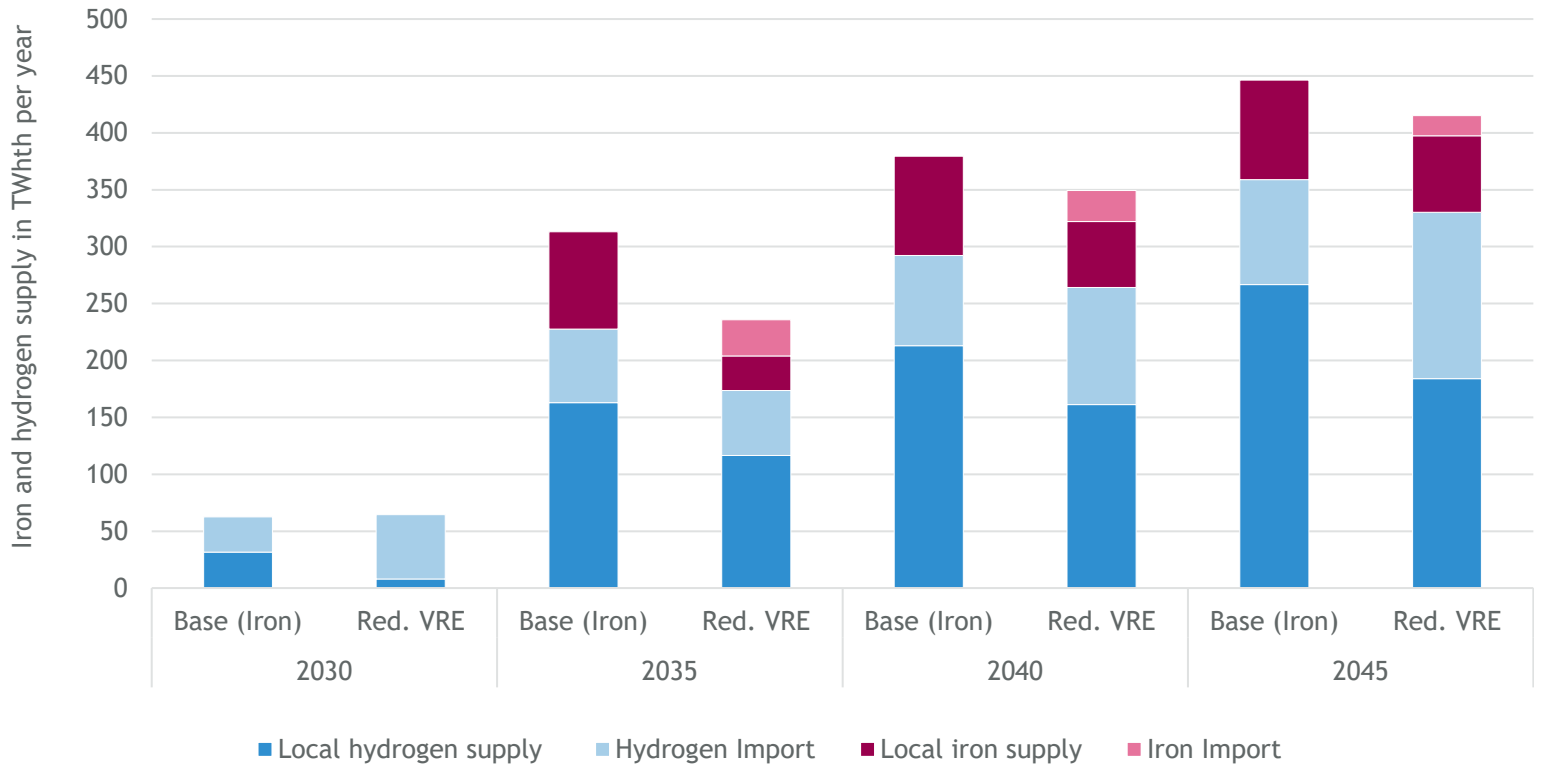
Comments

- In this sensitivity, VRE capacity is reduced by 25%. VRE generation declines accordingly, from around 1,291 TWh (Base) to 969 TWh (Red. VRE) in 2045.
- This has two effects: endogenous electricity demand declines, and dispatchable generation increases – natural gas generation roughly triples in 2030 (34 to 93 TWh), while iron retrofits add around 17 TWh by 2045.
- Nonetheless, VRE continues to supply the majority of electricity, accounting for roughly 85% of total supply in 2045.
- In addition, Germany turns from a net electricity exporter into a net electricity importer, with net imports rising to around 52 TWh by 2045.

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Reduced VRE expansion increases dependence on hydrogen and iron imports

Hydrogen and iron supply in Germany

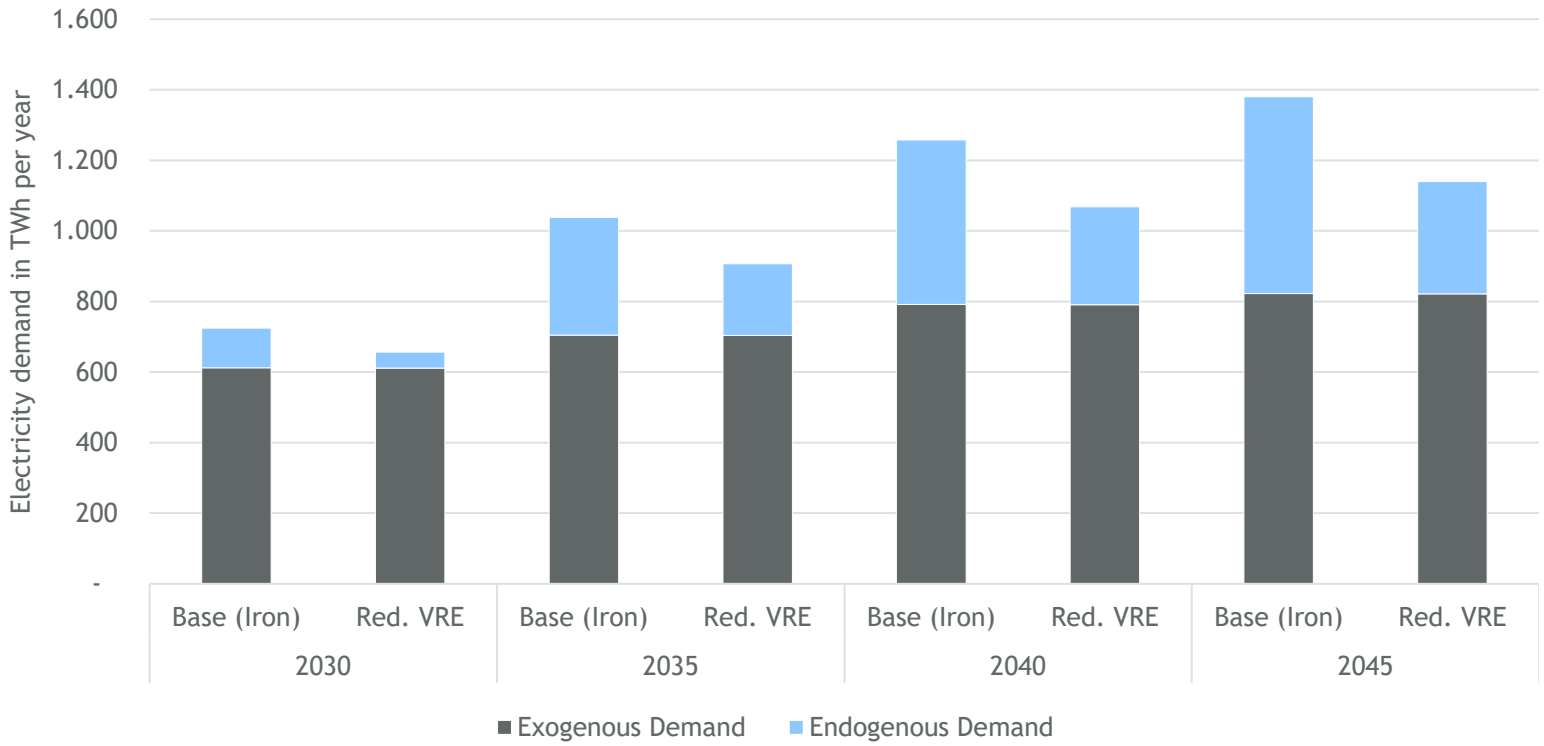


Comments

- If VRE capacity is reduced by 25%, imports of hydrogen and iron gain importance, as domestic production declines.
- Hydrogen imports rise from around 90 TWh_{th} (Base) to almost 150 TWh_{th} in 2045 (approx. +60%), increasing the import share of German hydrogen supply from around 26% to 44%.
- Iron, which is produced entirely domestically in the Base scenario, is now partly imported. Imports cover around 50% of iron supply in 2035 and 20% in 2045.
- With less low-cost VRE generation available for electrolysis and iron reduction, imports become a competitive supply option.

The drop in electricity demand is due to a drop in endogenous demand from Power-to-X capacities

Electricity demand in Germany

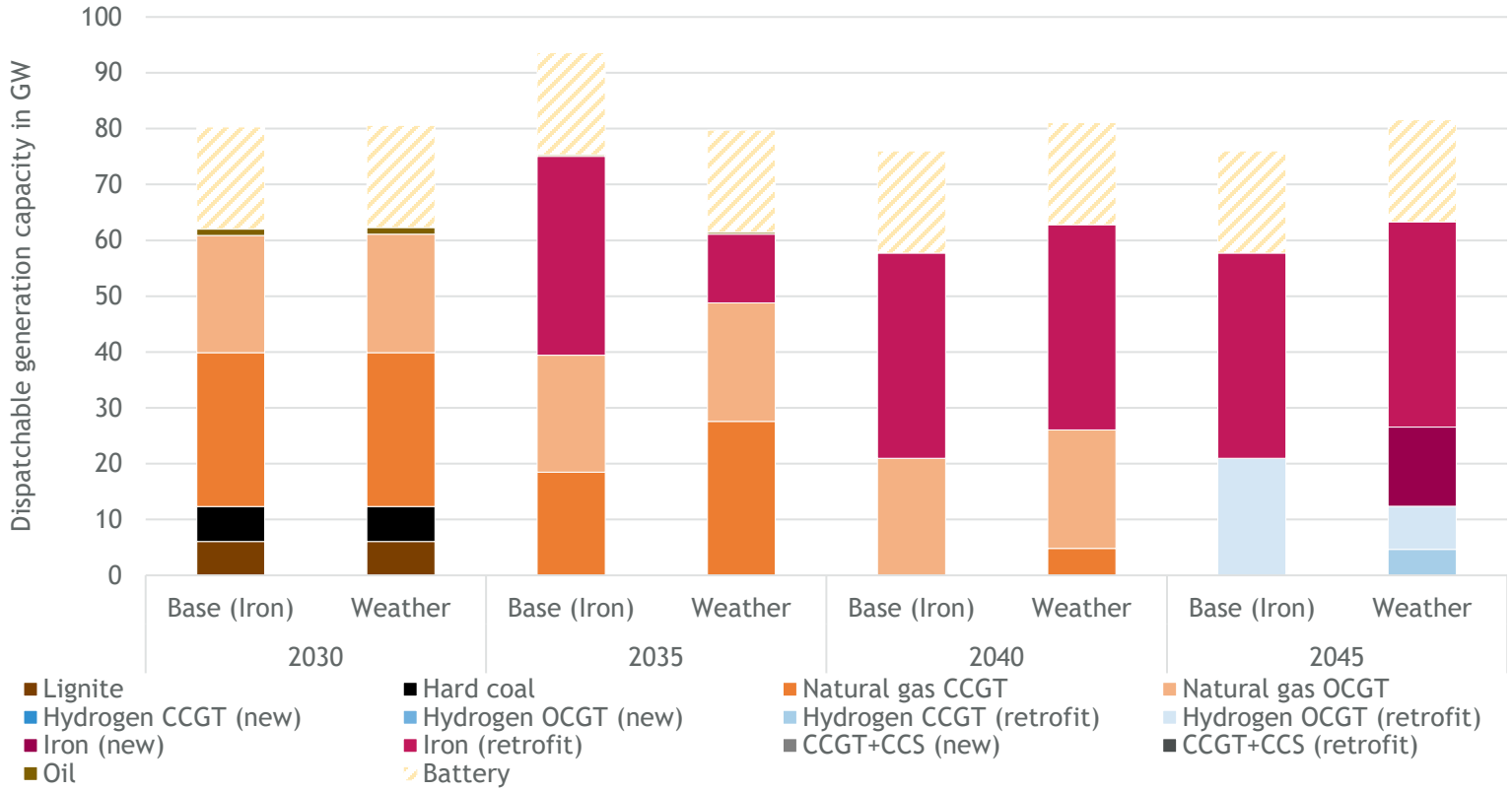


Comments

- As exogenous electricity demand is identical in both scenarios, the entire difference between the scenarios stems from endogenous demand: as VRE becomes scarcer, the flexible demand for electrolysis, iron reduction and electric boilers drops due to their lower efficiency compared to large heat pumps.
- By 2045, endogenous demand falls from around 560 TWh in the Base (Iron) scenario to roughly 320 TWh in the Reduced-VRE scenario, which represents a decline of around 43%.
- This is driven mainly by lower endogenous hydrogen demand, down from about 94 to 64 TWhth by 2045, while endogenous iron demand eases only slightly, from around 88 to 85 TWhth.

The weather sensitivity shifts dispatchable capacity towards less iron power plants in the short run and more in the long run

Endogenous dispatchable generation and storage capacities in Germany



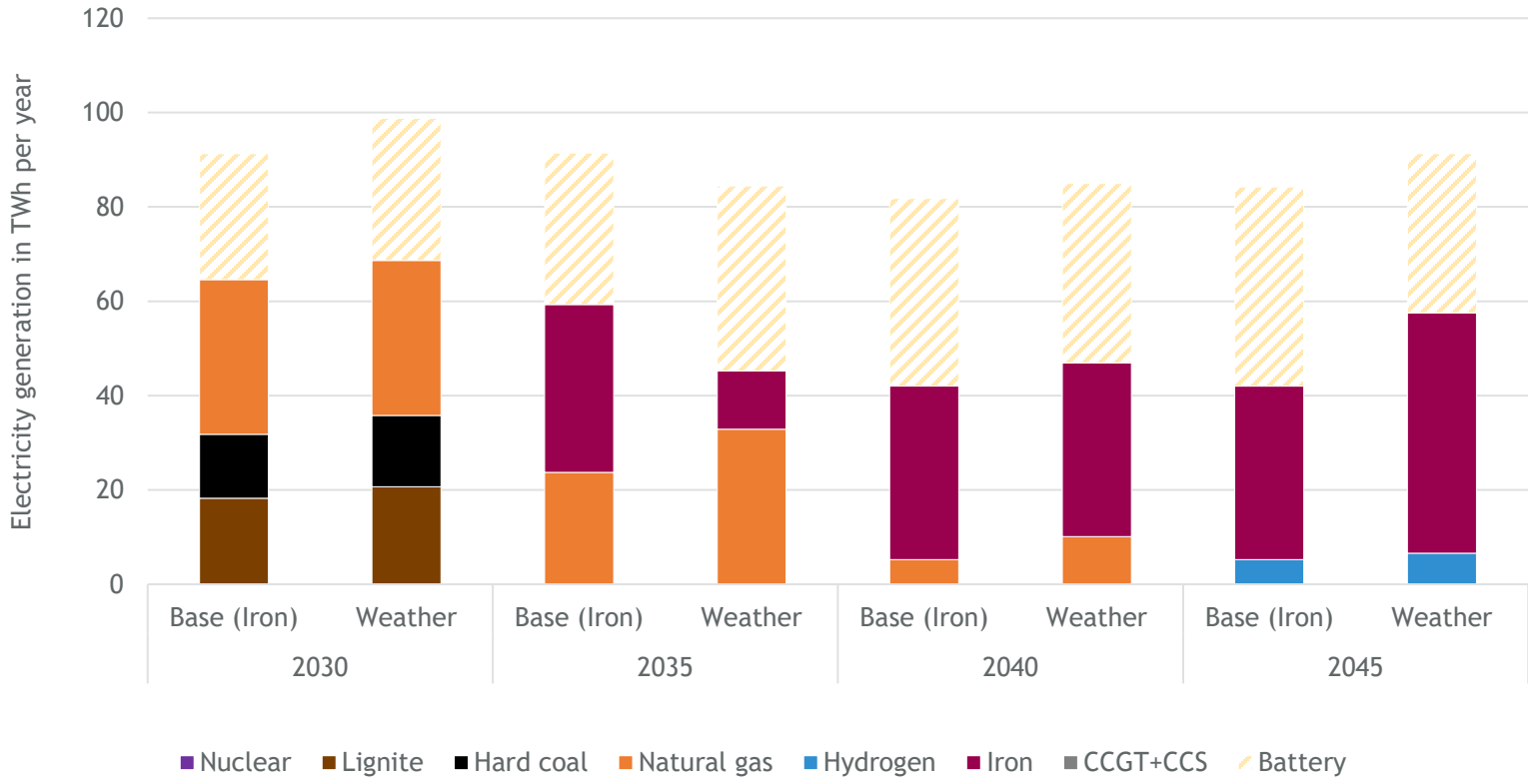
Comments

- The weather sensitivity shows that VRE capacity factors, hydro inflows and temperature-dependent demand significantly affect the resulting capacity mix.
- In 2035, less coal and lignite capacity is retrofitted to iron (12 vs. 36 GW). Instead, natural gas CCGTs remain in the market, and total dispatchable capacity is around 14 GW lower.
- This is consistent with the peak residual demand of this weather year, which is higher in the base weather year.
- In later years, generation capacities exceed the Base Scenario (roughly 63 vs. 58 GW). Natural gas CCGTs remain in 2040, enabling hydrogen CCGT retrofits in 2045. Also, new iron power plants contribute to the capacity mix by 2045.

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Regardless of the weather, iron becomes the dominant endogenous dispatchable source from 2040 onward

Dispatchable el. supply of endogenous generation and storage capacities



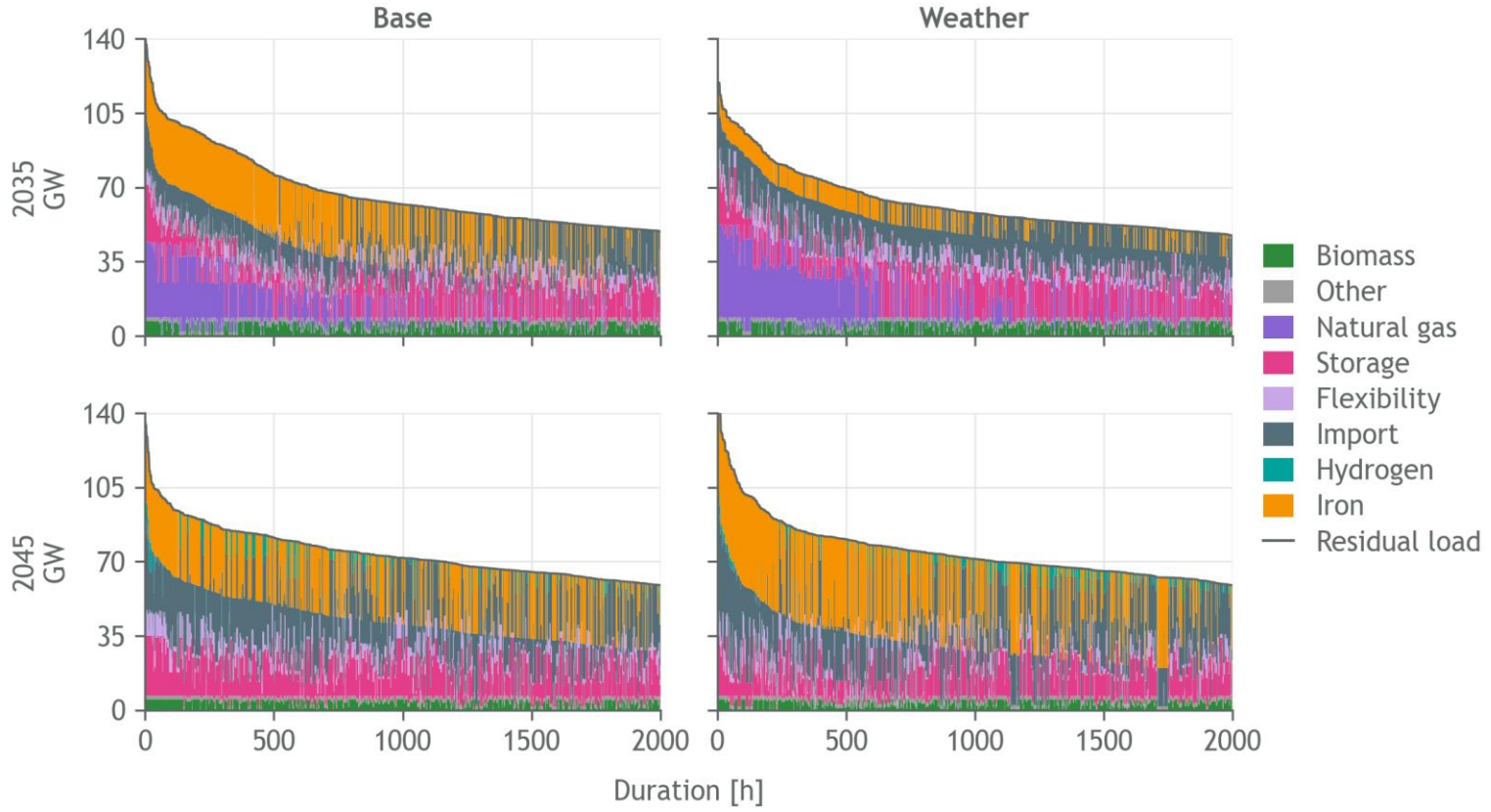
Comments

- Although installed capacities diverge, total dispatchable generation (and storage discharge) are similar in both scenarios in 2035.
- From 2040 onward, iron emerges as the dominant dispatchable technology in both scenarios (37 TWh each in 2040).
- Especially in 2045, iron generation is considerably higher in the weather sensitivity (51 vs. 37 TWh), consistent with the additional new iron capacity built in this sensitivity.
- Batteries provide a significant level of flexibility in both cases, while hydrogen power plants show similar generation levels between 5 and 7 TWh.

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The effect of the weather year also differs by model year: residual load falls in 2035 but rises in 2045

Residual load duration curve in Germany



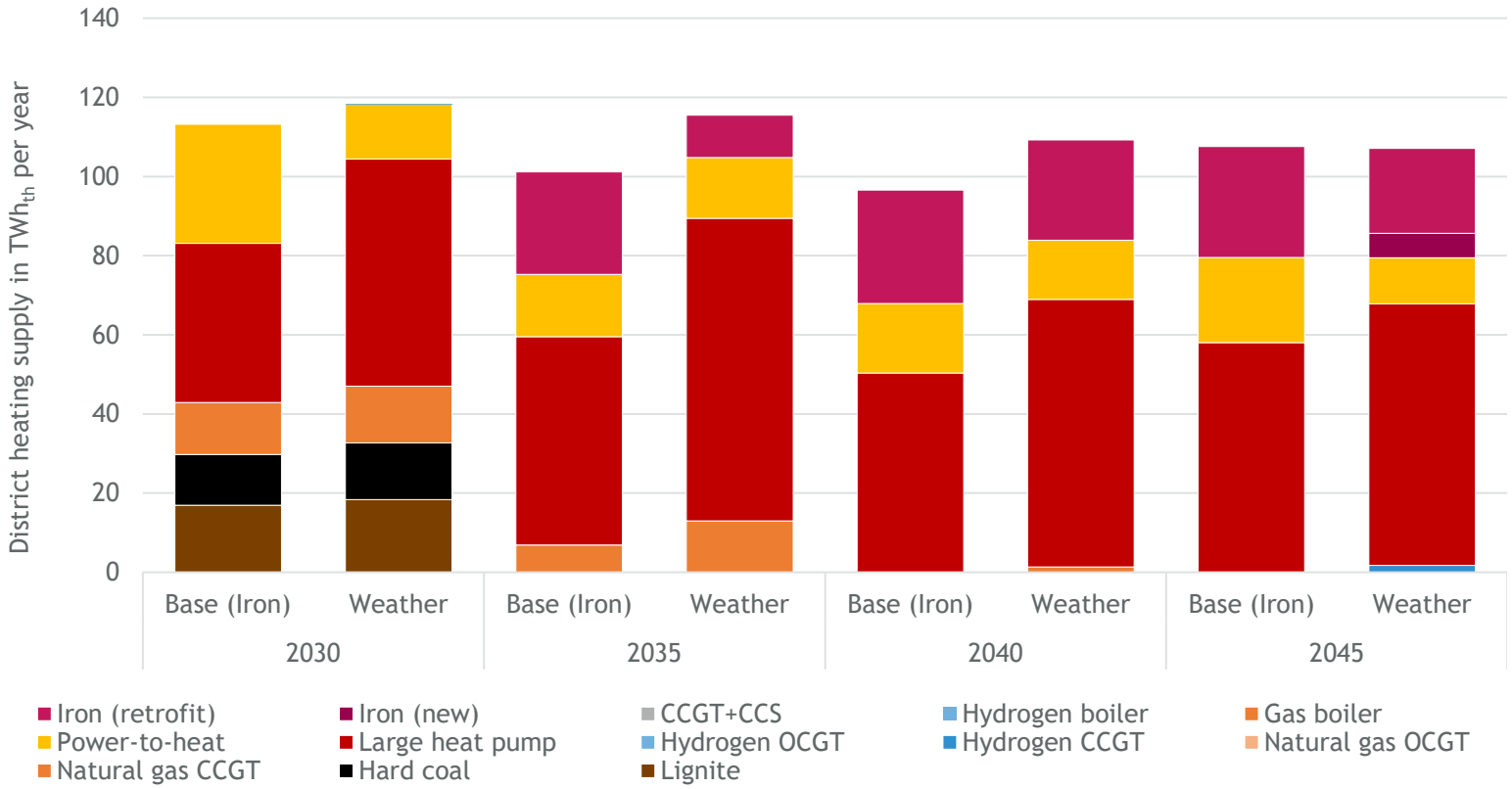
Comments

- Effects of the weather sensitivity are ambiguous across model years, as the base scenario applies a different weather year in each model year while the weather sensitivity keeps one fixed year.
- In 2035, residual load is notably lower in the weather sensitivity, driven by differences in demand and renewable capacity factors (e.g., onshore wind full-load hours are lower in the base in 2035, but higher in 2045).
- In the weather sensitivity, natural gas power plants dominate the German dispatchable supply in 2035, with iron playing only a minor role compared to the Base scenario.
- In 2045, the higher residual load in the weather sensitivity shifts capacity and dispatch towards iron-based generation, complemented by storage, imports and hydrogen.

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The cold weather year 1997 increases district heating demand - the additional demand is mainly covered by large heat pumps

District heating supply in Germany



Comments

- As 1997 represents a particularly cold weather year, district heating demand is higher than in the *Base* scenario – most pronounced in 2035.
- The additional demand is covered in a similar manner as in the *Base* scenario, with large heat pumps providing the main contribution, complemented by power-to-heat.
- Iron CHP plants also contribute to district heating. In 2035, their contribution is lower than in the Base Scenario (11 vs. 26 TWh_{th}), mirroring the delayed iron retrofits, before converging to around 22–28 TWh_{th} in later years.

Summary: The availability of iron as an energy carrier may change the configuration of a future decarbonized energy system



Our model results show that once iron is available, the mix of dispatchable capacities changes: **Iron becomes part of the cost-optimal mix** contributing a relevant share across scenarios and **reducing costs in the model region by up to 18 bn. €/a in 2040 and 2045**. Iron seems to mainly compete with CCGTs equipped with CCS and, partly, with hydrogen OCGTs. If a lower VRE capacity is assumed, all three dispatchable technologies are part of the cost-optimal mix. In **all scenarios except the *weather* scenario**, **iron power plants** solely consist of **retrofitted coal and lignite power plants**. The amount of electricity supplied by iron power plants as well as by the other endogenous dispatchable power plants is relatively small, indicating that their main role is to **provide firm capacity** in times of low renewable generation.



The **district heating demand** is **mostly covered by electricity-based heating systems** across scenarios. Large heat pumps generally provide the largest share and power-to-heat boilers cover peak heat loads. Combined heat and power generation takes a relevant share in all years and scenarios. While coal-, lignite- and natural-gas-fired CHPs supply heat in 2030 and 2035, **iron-fired plants as well as CCGT with CCS contribute a relevant share in the later years**. If iron-fired power plants are available, they contribute around 20% of the district heat demand in Germany compared to CCGT with CCS contributing less than 10%.



Hydrogen and **iron** are **mainly produced domestically in all scenarios**. **With iron available**, **the endogenous commodity demand**, both in the form of hydrogen and iron, **rises sharply with hydrogen used as input for the iron production**. The availability of **iron leads to** the **availability of cheap seasonal storage**, while simultaneously increasing utilization of renewables. While **iron is not imported at all** in the base scenario, some hydrogen is imported through pipelines with minimum utilization in long-term contracts and flexible spot market imports via ship. In the ***reduced VRE* scenario**, domestic hydrogen and iron production decrease while **imports for hydrogen and iron increase**.

The results are subject to several limitations

Model assumptions

- **Linear model:** The strict reliance on linear equations often drives the model toward extreme "winner-takes-all" solutions, where it deploys only the single cheapest technology while completely ignoring slightly costlier alternatives. This fails to reflect reality, where supply limits, risk aversion, and local preferences naturally lead to a more distributed and diversified technology mix.
- **Central planner**: The system assumes a single actor minimizes total costs for everyone, ignoring real-world market dynamics. It fails to capture decentralized decision-making, imperfect competition, and conflicting stakeholder interests.
- **Perfect foresight**: The model optimizes decisions assuming complete, advance knowledge of future weather, demand, and prices. This ignores real-world uncertainty (e.g., dark doldrum, new loads such as data centers or price shocks), often leading to overly optimal investment strategies that do not account for risk.
- **Spatial and temporal resolution**: Aggregating data into country nodes and representative typedays smooths out extreme local demand peaks and weather variations. Consequently, the model may miss short-term capacity shortfalls and highly localized grid bottlenecks.

Implementation challenges

- The implementation challenges are partly investigated with the scenarios and sensitivities. However, some limitations persist.
- **Technology availability**: It is assumed that the entire value chains of hydrogen, CCS and iron reduction are fully available. By this we abstract from technological readiness, that may delay the availability of these technologies. Additionally, we assume that coal capacities active in 2024 can be retrofitted in the future. However, this is only possible if capacities are not deconstructed and kept in good state.
- **Construction of infrastructure**: Delayed and more expensive infrastructure is captured in the *Reduced VRE* and *Iron Expensive* sensitivities. Nonetheless, financing, construction time and social acceptance remain outside the model. Additionally, the assumed availability of (inter-)national hydrogen and CO_2 infrastructure is a simplification: these networks are yet to be built and depend on the ramp-up of hydrogen demand or the regulatory framework, whereas iron can build on existing transport routes.
- **Availability of energy**: With the *weather* sensitivity, varying VRE capacity factors and demand on the energy system are investigated. However, the availability of imports from outside the model region remains uncertain.

Uncertain electricity demand could raise the relevance of iron imports beyond the modeled levels

Electricity demand uncertainty and iron imports

- **Industrial electricity demand:** Future electricity demand from industry is uncertain in both directions. Comparatively high European electricity prices could drive energy-intensive industry abroad, while AI data centers could raise demand sharply in the regions where they are built. Exogenous electricity demand follows the National Trends path in all scenarios and captures neither development.
- **Secondary effects of iron:** The analysis indicates that iron can lower the cost of the European electricity system. Lower system cost should translate into lower electricity prices and thereby stimulate additional electricity demand. As demand is largely exogenous, this feedback mechanism is not captured.
- **Implications for iron import:** Both effects potentially point in the same direction as the Reduced VRE sensitivity. Domestic production is bounded by the exogenously fixed VRE capacity, so additional demand would have to be met by imports. Iron is not imported at all in the Base scenario, but it is the only carrier whose import is not limited by terminal or pipeline capacity. Its import share could therefore rise well beyond the levels shown here.

Further considerations outside the scope of this report[1]

- **Water intensity:** An important differentiating factor between iron and hydrogen imports is the technologies' water cycle. Exporting hydrogen permanently removes water from the producing region, as the water split in the electrolyzer is bound in the hydrogen and released upon consumption in Europe. In the iron route, the water formed during reduction stays at the production site and can thus be returned to the electrolyzer while the iron dust is exported, leading to a much lower water intensity.
- **Role of batteries:** Batteries are modelled in line with the TYNDP assumptions, and they compete directly with iron as potential electricity supply sources. The extent to which battery storage can provide system services such as reactive power compensation, island operation capability or short circuit current is contested. Thermal power plants have demonstrated in the past that they can offer these services.

1: The provided list is non-exhaustive.

Conclusion: Iron as an additional technology option may increase the chances for an affordable, secure and sustainable energy system

1

Our analysis shows that **iron** can be part of a cost-optimal energy system and may therefore **improve all three aspects of the Energy Policy Triangle** compared to current decarbonization plans: sustainability, affordability and security of supply. This contribution, however, partly **depends on the availability of coal and lignite power plants to retrofit**, which lead to low cost of iron-fired power stations. To use this advantage, **decommissioned coal and lignite power plants would need to be preserved**.

2

Iron is especially complementary with a high share of VRE capacities. With sufficient renewable electricity in the energy system, **iron offers a cheap seasonal electricity storage** and can contribute to **decarbonizing district heat**. **With high VRE capacities as well as iron reduction and iron storage available, the dependence on energy imports decreases**. With reduced VRE capacities, iron import becomes relevant.

3

Iron provides a third option for carbon-neutral dispatchable generation next to hydrogen and CCS. An additional technology can **increase the resilience of a decarbonized energy system to the previously defined implementation challenges**. Accordingly, iron could be considered as an **additional technology in the scope of upcoming energy planning studies**.

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EWI – Institute of Energy Economics at the University of Cologne

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Modeling details for final demand, weather year and CO_2-budget

Final demand

Annual final electricity and hydrogen demands for the residential, commercial, industrial, transport and agriculture sectors are taken from the TYNDP National Trends scenario and disaggregated to hourly resolution using the 2025 BDEW standard load profiles.[1,2] Hourly heating and cooling demands are derived from temperature time series via the Heating/Cooling Degree Hour (HDH/CDH) approach. Demand as well as capacity factors are clustered in typedays to reduce model complexity. The typeday resolution is 122 days with 24h per year.

Weather year

The weather year evolves over the modelling horizon, following the same climate projections underlying the TYNDP scenario framework. While TYNDP selects and combines a set of probability-weighted weather years from three different climate models for each target year, this model relies on a single weather year per target year, drawn exclusively from the most prominent climate model CMR5.[3]

CO_2-budget

The CO_2-budget is restricted to the TYNDP's power sector emissions with a steady decline from 2030 to 2050. For Germany, the CO_2-budget is set to zero in 2045 already.

1: ENTSO-S (2026): TYNDP National Trends scenario, 2. BDEW (2025) Updated Standard Load Profiles 3: ENTSOS (2026): TYNDP Methodology Report

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Modeling details of commodity production, district heat generation and electricity generation

Commodity production



Both hydrogen and iron production are modeled daily. Electrolyzer capacity for the start year 2030 is given exogenously based on the TYNDP 2026. Electrolyzer and iron reduction capacity are modeled endogenously for the rest of the time-period. The electrolyzer takes electricity as input, while iron reduction takes both hydrogen and electricity as input.

District heat generation



District heat generation is modeled daily and aggregated as national demand. District heat can be supplied by combined heat and power stations, boilers as well as heat pumps. Coal, lignite, iron power plants as well as CCGT power plants are able to supply district heat along electricity generation. For boilers, natural gas, hydrogen and electrical boilers are available technology options. Heat pumps are modeled as water-based large heat pumps. Capacities are endogenously modeled with a greenfield approach, as the TYNDP does not provide district heat capacities. Due to the daily modeling approach, district heating storages are neglected as the benefit for the model results is low compared to the computational effort.

Electricity generation



Electricity generation is modelled with an hourly resolution. Generation capacities for 2030 are given exogenously based on the TYNDP 2026. Renewable capacities (onshore wind, offshore wind, PV utility, PV rooftop, run-of river) as well as some dispatchable power plants (nuclear, biomass, oil, others) are given for the considered time-period. The model endogenously sets electricity generation capacity for natural-gas-fired and hydrogen-fired OCGT and CCGT, CCGT with CCS and iron-fired power plants. For coal and lignite power plants, the model can endogenously decide when to subtract capacity but cannot add new capacity.

Modeling details of additional restrictions for electricity generating power plants

Retrofit



Instead of investing into new power plants, the model can retrofit existing power plants. Natural-gas-fired OCGT and CCGT can be retrofitted to hydrogen-use and CCGT can alternatively be retrofitted with CCS. Coal and lignite power plants can be retrofitted to use iron as their fuel. The model can invest into the retrofit of power plants in the year, where the existing capacity is endogenously subtracted. For retrofit of lignite and coal, additional decommissioned power stations are available for retrofit if they are still active in the year 2024. Other technologies like Carnot-Batteries could further improve cost efficiency of this technology but are not considered in this report.

Minimum run conditions



The power plants are subject to minimum run obligations in different forms. First, all endogenous power plant capacities need to fulfill minimum full load hours to ensure reasonable investments. OCGT power stations must run for at least 250 full load hours per year. All other endogenous capacities (all forms of CCGT, coal, lignite and iron-fired power plants) must run for at least 1000 full load hours per year. This rule is applied to prevent an unrealistic dispatch of power plants in the linear model (e.g. 5 full load hours). Additionally, nuclear, biomass and “others” power plants are subject to annual minimum run obligations. They can flexibly set the generation within a given operation frame in each hour.

CCS



CCGTs equipped with carbon capture units are counted as 100% decarbonized technology. For every unit of electricity generated, an additional cost for CO_2 transport and storage[1] is considered. For CCS, a CO_2 capture rate of 90% is assumed. The residual emissions are assumed to be captured by direct air capture (DAC) systems. The DAC cost per ton CO_2 is set based on literature values[2].

1: EWI (2025) | 2: Sievert et al. (2024)

Modeling details of demand flexibility, electricity and commodity storage

Demand flexibility



Demand flexibility is accounted for in several ways. For electricity, demand shifting by electric vehicles and heat pumps is considered, as well as price sensitive demand reduction by industrial demand. The demand shifting for electric vehicles is based on Lilienkamp and Namockel (2024)[1]. It is assumed that a quarter of home charging can be shifted. Shifting of heat pumps assumes that 25% of heat pump demand in a given hour may be shifted. However, over the day heat pump demand must be fully met. Demand reduction follows the TYNDP modeling with 6 different demand reduction levels depending on different price levels. For hydrogen, a similar demand reduction is implemented for very high prices.

Electricity Storage



For electricity storage, several technologies are considered. The first to be regarded are batteries, which follow the TYNDP data with a storage duration of 4 hours. Invest and dispatch of batteries is endogenous, giving the model the possibility to invest into short-term flexibility. Additional to batteries, pumped hydro storages and hydro reservoirs are considered. Both are given exogenously with country-specific capacity, storage duration and external inflow data from the TYNDP. Contrary to hydro reservoirs, pumped hydro storages can be charged. All electric storages have a cycle efficiency deducted.

Commodity Storage



Both hydrogen and iron storages are modeled endogenously. The power capacity of iron storages is coupled with the iron-fired power stations, while the energy capacity can be freely set. Hydrogen storages are modeled with an independent invest into injection capacity, withdrawal capacity as well as energy capacity or storage volume due to highly differing cost for these components. Both repurposed as well as newly built hydrogen cavern storages can be built by the model. Both repurposed and newly built caverns are restricted by a country-specific potential.

1: Lilienkamp and Namockel (2024)

Modeling details of non-EU import, trade and distribution

Non-EU Import



Commodity import from outside of the model region is possible for both hydrogen and iron. For both commodities import per ship is possible in two variants: via long-term contract or via the spot market. The commodity amount imported via long-term contracts is fixed per day and must also be imported and paid in later years. This obligation is not given for spot market import, which can be used flexibly. However, spot market import is 20% more expensive and only available from 2045 onwards. For hydrogen, there is an additional long-term contract import way via pipelines, which are subject to an 80% take-or-pay rate, i.e. the model needs to utilize at least 80% of the pipeline capacity each day. Hydrogen import pipeline and terminal capacity are given based on the TYNDP in each year, terminal capacity for iron is unlimited. The given hydrogen import pipeline capacity coupled with the minimum run condition forces the model to import hydrogen.

Trade



Trade between nodes is possible for electricity, hydrogen and iron. Trade of district heating is not possible. While iron trade is unrestricted, electricity and hydrogen trade is restricted by net-transfer capacities and reference transmission capacities of the TYNDP. For both networks additional capacities are added for nodes without any data given, e.g. Norway and UK. Electricity and hydrogen trade are subject to efficiency losses, while transportation costs apply for both hydrogen and iron.

Distribution



Distribution of all commodities, i.e. electricity, hydrogen and iron are neglected within the model, due to high uncertainty of distribution cost for each commodity as well as endogeneity problems. Iron reduction could reduce congestion in the electricity grid by storing local generation surpluses.