International PtX Hub

Supported by:

Federal Ministry for Economic Affairs and Climate Action

on the basis of a decision by the German Bundestag

IKI INTERNATIONAL CLIMATE INITIATIVE

Implemented by

giz Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH

PtX Allocation Study for South Africa

Power-to-X to enable and advance the long-term transformation of South Africa's Energy System

Agora Industry

Fraunhofer IEE

Stellenbosch University Iyunivesithi Universiteit

Supported by:

Federal Ministry for Economic Affairs and Climate Action

on the basis of a decision by the German Bundestag

INTERNATIONAL CLIMATE INITIATIVE

Implemented by

Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH

IMPRINT

As a federally owned enterprise, GIZ supports the German Government in achieving its objectives in the field of international cooperation for sustainable development.

Published by:
Deutsche Gesellschaft für
Internationale Zusammenarbeit (GIZ) GmbH

Registered offices:
Bonn and Eschborn, Germany

International PtX Hub
Potsdamer Platz 10
10785 Berlin, Germany
T +49 61 96 79-0
F +49 61 96 79-11 15

E info@ptx-hub.org
I www.ptx-hub.org

Responsible:
Frank Muenk (GIZ), Zaffar Hussain (Agora Industry)

Researchers:
Lukas Jansen, Estefanía Duque Pérez, Jochen Bard, Benedikt Häckner (Fraunhofer Institute for Energy Economics and Energy System Technology)

Storm Morison, Prof. Bernard Bekker (Stellenbosch University)

The International PtX Hub is implemented by the Deutsche Gesellschaft fur Internationale Zusammenarbeit (GIZ) GmbH on behalf of the German Federal Ministry for Economic Affairs and Climate Action (BMWK). Financed by the International Climate Initiative (Internationale Klimaschutzinitiative, IKI), the International PtX Hub is a contribution to the German National Hydrogen Strategy of 2020 and represents one of the four pillars of the BMUV's PtX action programme initiated in 2019.

June 2025

Disclaimer

The model- and scenario-based analysis in this study contributes to the assessment of South Africa's energy system pathways under different levels of policy stringency and market development. This study developed the first multi-sector, multi-regional and hourly resolved model for South Africa. While the results are based on an innovative approach, it is important to note that the quantitative results of this study depend on the assumptions made for the years 2030 to 2050 in different scenario and sensitivity settings.

The main scenarios defined and analysed are the Current Policy [1] (CP), the Net-Zero (NZ) and the Net-Zero Early Export (NZEE) scenarios. The exogenous assumptions for the final energy demands of these scenarios largely follow existing policy or strategic objectives and inherit a lot from the Just Energy Transition Plan. The first application of a cross-sectoral model with high spatial and temporal resolution also has to deal with missing georeferenced data sets. One challenge, for example, is the spatial disaggregation of final energy consumption. To date, the authors are not aware of any comprehensive, complete, spatially specific datasets on energy or hydrogen consumption today or in the future and therefore had to make estimates.

The scenario results should not be understood as forecasts with probabilities, but as optimisation results subject to boundary conditions and a set of techno-economic assumptions. In general, the energy demand and cost assumptions are estimates from today's perspective. With changing global developments or national regulatory environments, they need to be updated. The most important assumptions were presented and validated in three stakeholder consultation and workshop events during the project.

The study was conducted and written before the publication of the TDP 2024 and the IRP 2024.

In this sense, the analysis provides a comprehensive framework for stakeholders to assess required investments, policy needs, technological innovations required and important to steer the country towards a sustainable energy future.

1 The CP scenario follows the planned coal phase-out path and assumes a more inefficient future energy system. However, the CP scenario does not limit the nation-wide expansion of wind or solar PV.

Content

List of tables

List of figures

Executive Summary

Context and Significance. The global economy and energy transition is driven by the imperative to combat climate change and achieve climate neutrality by 2050. Among the array of solutions, electricity-based sustainable molecules and fuels, commonly referred to as Power-to-X (PtX) products, have emerged as critical components in governments' strategies. These products, which include green hydrogen and synthetic fuels, will play an essential role in the defossilisation of industries, long-haul aviation and shipping and will function as backup energy in power systems with high renewable energy penetration. The International PtX Hub, through initiatives like PtX Pathways, aims to foster the development of sustainable hydrogen and PtX markets in countries with significant renewable energy potential, such as South Africa, Morocco, and Argentina. This allocation study focuses on South Africa, exploring the potentials, challenges, and least-cost or no-regret decisions surrounding the development and utilisation of PtX products.

Background and Scope of the Study

South Africa (SA) is in a crucial phase, facing significant challenges related to energy security and the global shift towards a net-zero economy. The economy and population have suffered frequent power outages for over a decade, with more than 16 TWh of unserved energy due to load shedding experienced in 2023 [1]. The public electricity utility is in an uncertain financial situation, which could delay electricity grid investments required to integrate renewable energies [2]. Additionally, the share of fossil fuel imports increased from 35% in 2020 to 61% in 2023 [3]. With the methane-rich gas from Mozambique expected to be depleted by 2026, this supply will need to be replaced by LNG imports [4]. This situation makes SA more vulnerable to global fossil price shocks. Investments in new infrastructure, generation capacity and detailed planning are thus essential to address the current high level of risks and uncertainties.

Adding to these pressures, the global shift towards net-zero presents substantial risks to SA's carbon-intensive industries that have long been powered by coal. Currently, coal-based electricity generation constituting 80.1 % of total annual electricity production [5], the production of up to 160.000 barrels per day via coal-to-liquid, and further coal-reliant industries are collectively making SA one of the top 20 most carbon-intensive economies globally [6]. As international markets and key trading partners adopt stricter low-carbon policies, South Africa's economic stability and competitive edge are increasingly at risk. Seven major export markets, including the EU, USA and China, have set net-zero targets. The EU has launched the first phase of a carbon border tax mechanism, which, from 2026, will impose a CO_2 levy on products imported into the EU from countries that do not have a CO_2 price equivalent to that of the EU.

However, SA has great potential to unleash a transformation of its energy landscape which could drive economic growth, improve energy security, and enable new export opportunities to international markets. Globally, government strategies have emphasised the pivotal role of green Power-to-X (PtX) molecules, fuels and feedstocks in transforming the industry, transport, and mining sectors and balancing power systems with high wind and solar PV penetration.

According to global net-zero and hydrogen trade studies [7–9], it is estimated that between 150 to 200 million tons per annum (mtpa) of hydrogen and its derivatives will be transported over long distances and across borders depending on various scenarios and assumptions regarding hydrogen adoption, infrastructure development and policy support. Of this traded volume, around 45% would be shipped [9], resulting in a market volume for the shipping portion of internationally traded hydrogen of 68 to 90 million tonnes annually. South Africa is well-positioned to become a key player in the emerging green PtX markets by leveraging its natural and industrial strengths. On the supply and manufacturing side, the country is well-positioned due to its abundant suitable land area, world-class solar and wind resources, expertise and existing assets for synthetic Fischer-Tropsch crude production, and a mature iron and platinum mining sector. In terms of local demand, previous studies highlight significant regional offtake potential for green PtX in hard-to-abate sectors such as the iron and steel industry, as well as its current applications as feedstock in various industries, and in aviation and shipping. According to these studies the projected local PtX demand could become significant by 2030 [10, 11] and will then contribute to the development of business cases and the scaling up of PtX projects. The resulting economies of scale will contribute to achieving cost competitiveness for both local and exported hydrogen. To enable the large-scale implementation of green PtX for both export and domestic applications, however, it is crucial to expand renewable capacities and to invest in national grid and logistical infrastructure.

The study's objective is to provide decision-makers with a model-based exploration of transformation pathways for PtX development. It aims to identify cost-effective, least-regret pathways for scaling PtX production, aligning renewable energy capacity expansion with domestic and export demands for green hydrogen, ammonia, and synthetic fuels.

Key objectives of this project are to:

- Identify and fill relevant knowledge gaps with a focus on PtX in existing transformation studies,
- Develop coherent scenario designs through dialogue with key South African stakeholders,
- Develop an open-source model of the South African energy system for further studies,
- Identify and evaluate promising pathways for the expansion and utilisation of renewable energy and PtX for South Africa,
- Derive insights for South Africa's long-term energy and defossilisation strategy.

The outcome will help explore uncertainties, assess trade-offs, and identify critical enablers for South Africa's energy transition, ensuring alignment with its climate ambitions.

Methodology and Data

The analysis employs a scenario-based approach to model different energy system transformation pathways. The study develops and utilises a sector-coupled PyPSA-RSA-Sec building on the mature open-source electricity system model PyPSA-RSA. PyPSA-RSA-Sec is a high-resolution, cross-sector energy system model tailored to South Africa's needs. The scenarios explore varying levels of PtX adoption, renewable energy deployment, and export potential, accounting for technical, economic, and policy factors. These scenarios are aligned with South Africa's Just Energy Transition Investment Plan (JET-IP) and Generation Connection Capacity Assessment (GCCA), integrating data from global hydrogen trade studies and national infrastructure assessments.

Scenarios

The energy system in South Africa faces significant uncertainties due to global shifts in energy markets, policy directions, and local challenges such as grid reliability and the performance of coal-based facilities. To address these uncertainties, this study defines three scenario pathways, each based on different assumptions about policy measures, market developments, and technology constraints. These scenarios aim to explore medium- to long-term projections and assess the implications for system costs, PtX export opportunities, renewable energy expansion, and overall energy transition pathways.

Table 1: Summary of three main scenario pathways CP, NZ and NZEE explored in the study

Key drivers	Current Policy (CP)	Resilient Net-Zero	NZ + Early Export (NZEE)
CO_2 Policy	No budget limits, CO_2-price, ESKOM plans for coal phase-out	50MtCO_2 in 2050, 8.3 GtCO_2 budget, CO_2 price, Coal phase-out by 2040	= NZ
PtX export	Delayed and low exports (10% of High), Products: Ammonia, Fischer-Tropsch fuels	= CP	High exports for Ammonia and FT fuels, all projects fo online as announced
Wind, PV expansion	2030 -> Limits for four western regions, otherwise free expansion	= CP	Free expansion, assuming on-&off-grid generation
Grid expansion	Limit of +10% existing inter-regional transmission capacities up to 2050	= CP	= CP
Transport sector	Delayed transition to efficiency, modal shift, and new electric vehicles	Ambitious transition to efficiency, modal shift, and new electric vehicles	= NZ
Industry sector	Delayed transition to innovative technologies (e.g. DRI) and efficiency	Ambitious transition toinnovative techs & higher domestic fertilizer production	= NZ

The scenarios are shaped by the following **key drivers** identified in extensive exchange with stakeholders:

- CO_2 Policy: Includes CO_2 limits, carbon pricing, and coal phase-out strategies.
- PtX Export: Defines export volumes and prices based on domestic project developments and global market trends.
- Wind and PV Expansion: Specifies regional and national restrictions on renewable energy growth.
- Grid Expansion: Describes the limits on transmission grid capacity expansion.
- Transport Sector: Determines the development of vehicle fleets and demands for shipping and aviation.
- Industry Sector: Addresses the growth and transformation of industrial production methods.
- Based on these key drivers three scenario pathways the Current Policy Path, Resilient Net-Zero Path and Net-Zero + Early and High Export Path are developed.

Scenario CP: Current Policy

- Reflects current policies with no new CO_2 limits but follows a CO_2 pricing trajectory.
- The phase-out of coal is gradual, and the expansion of renewable energy, while optimized, is regionally constrained, particularly in Cape provinces due to grid limitations.
- Power-to-X (PtX) market development is limited, with exports capped at 10% of the Net-Zero Export scenario.
- Transition to electric vehicles and low-carbon technologies in transport and industry is slow.

Scenario NZ: Resilient Net-Zero

- Focuses on achieving a sustainable transition aligned with global net-zero goals.
- Implements ambitious CO_2 policies, including a coal phase-out by 2040 and a CO_2 budget in line with global IPCC scenarios.
- Renewable energy expansion is constrained regionally like in CP, but transport and industry undergo a rapid transformation with a strong shift toward efficient, low-carbon technologies.
- Gradual replacement of imported fertilizer with domestic green ammonia production.

Scenario NZEE: Net-Zero + High and Early Exports

- Builds on the Net-Zero scenario with a focus on high PtX exports, with all domestic projects expected online by 2030.
- Unrestricted expansion of wind and solar projects, justified by the ability to support both grid-connected and off-grid hydrogen production.
- Rapid transformation in transport and industry sectors, with high adoption of clean technologies.
- Continued replacement of imported fertilizer with domestic green ammonia production.
- These scenarios provide a range of potential pathways for South Africa's energy transition, highlighting trade-offs and opportunities for achieving decarbonization while leveraging PtX technologies and renewable energy.

Conclusions and Recommendations

The model- and scenario-based analysis in this study contributes to the assessment of South Africa's energy system pathways under different levels of policy stringency and market development. This study developed the first multi-sector, multi-regional and hourly resolved model for South Africa. While the results are based on an innovative approach, it is important to note that the quantitative results of this study depend on the assumptions made for the years 2030 to 2050 in different scenarios and sensitivity settings. The main scenarios defined and analysed are the Current Policy [2] (CP), the Net-Zero (NZ) and the Net-Zero Early Export (NZEE) scenarios. The exogenous assumptions for the final energy demands of these scenarios largely follow existing policy or strategic objectives and inherit a lot from the Just Energy Transition Plan. The scenario results should not be understood as forecasts with probabilities but as optimisation results subject to boundary conditions and a set of techno-economic assumptions. In this sense, the analysis provides a comprehensive framework for stakeholders to assess required investments, policy needs, and technological innovations required to steer the country towards a sustainable energy future. The most important conclusions from the model-based analysis and recommendations for action follow.

---

2 The CP scenario follows the planned coal phase-out path and assumes a more inefficient future energy system. However, the CP scenario does not limit the nation-wide expansion of wind or solar PV.

South Africa's energy landscape needs to be prepared for a 2.6x to 4.3x times increase in electricity consumption compared to 2022 on the way to an efficient, climate-neutral system.

Electricity demand increases by a factor of 2.6 to 4 across all scenarios compared to 2022. The increase in electricity consumption is due to direct and indirect (via PtX) electrification for various end uses. The electricity load of today's industry sectors will double by 2050. New electric vehicles will lead to an electricity consumption of 59 to 64 TWh by 2050. Cooling, heating, cooking and other applications in the residential sector will continue to be electrified (+30% from 2030 to 2050).

The green PtX fuels and feedstock economy consumes 95 to 406 TWh of electricity in the three main scenarios by 2050. In 2050, the consumption of H_2 electrolysis at 406 TWh is 4.3 times as high as in CP. The share of electricity consumption of H_2 electrolysis is 50% of the net electricity consumption of 817 TWh (without battery) in the ambitious net-zero and export scenario NZEE.

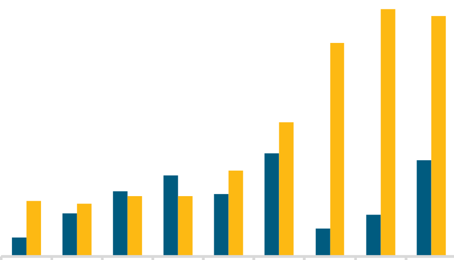
An unprecedented roll-out of wind and solar power capacities is key for both least-cost supply of increased electricity demands and for unlocking the development of green PtX production.

In all scenarios analysed, wind and solar energy confirm their status as cornerstones of the supply of South Africa's growing future electricity demand. At minimum in 2050, the total capacities of wind and solar are around 6.7x times higher than the installed coal power capacity of 2023 (39 GW) [12] and at maximum 10x times higher.

In terms of the ratio of solar to wind generation, the optimisation model recommends a solar to wind generation mix of around 2:3 to 2.5:3 (solar to wind) in NZ and NZEE before 2050, shifting to 3:2 in 2050. This mix is chosen by the model based on CAPEX and the need to curtail renewables. This mix balances the variability of volatile generation over time and space as much as possible. The higher solar shares in NZ and NZEE in 2050 indicate that solar is the cheapest source of electricity and can be well integrated with H_2 electrolysis and smart charging of electric vehicles as they become available in large numbers. Prior to 2050, the emphasis will need to be on procuring wind and solar with the above shares.

In terms of total renewable capacity, NZ and NZEE require 9 to 21 GW more capacity by 2030 than CP (41 GW), and NZEE surpasses NZ with an additional 92 GW by 2050 (30% more than NZ). These substantial installations will require significant grid upgrades to connect and integrate the increased capacity.

To achieve the optimal capacity targets by 2050 in the scenarios focussing on domestic demands (CP, NZ), the average annual build rate for wind ranges from 1.1-3.6 GW/year among periods and from 3.1-14.4 GW/year for solar PV. The expansion of solar PV has to increase significantly for the period 2040 to 2050. The highest wind power build rates are observed for the period 2030-2040. If South Africa aims to capitalize on high export opportunities, the required per anno expansion for wind increases to 3.8 (+52% to NZ), 6.0 (+67% to NZ) and 5.6 GW (+133%). The annual solar build rate is significantly higher (7.8GW/year, +56%) from 2030-2040 but similar to NZ otherwise. These build rates far exceed current national plans, emphasizing the need to incorporate export potential and the results of least-cost optimisations into future energy planning.



	CP	NZ	NZEE	CP	NZ	NZEE	CP	NZ	NZEE
	2023-2030			2030-2040			2040-2050		
Wind (GW/yr)	1.1	2.5	3.8	4.7	3.6	6.0	1.6	2.4	5.6
Solar (GW/yr)	3.2	3.1	3.5	3.5	5.0	7.8	12.4	14.4	14.0

Figure 1: Average annual wind and solar build rates required for the periods 2023 – 2030, 2030 – 2040 and 2040 – 2050 for each of the scenarios.

In comparison to the latest plans, such as the IRP 2023 Draft, the results highlight the significance of NZEE and this PtX-focused study for political and industrial decision-makers and for planning the expansion and investment needs for grid and pipeline infrastructure. It indicates that a rapid expansion of renewable energy, far beyond most existing plans, is necessary to satisfy the projected domestic demands and facilitate early exports.

Substantial battery capacities, as well as moderate gas turbine and LNG import capacities are required to integrate renewable energies and to meet the sectoral methane demands – latter, however, only for a limited time frame.

Given the scenario setting (e.g. no Vehicle-to-Grid) and the model's scope, large scale battery capacities are needed latest by 2040 with 4 – 16 GW, going up to 46 – 50 GW by 2050. Batteries help to integrate solar and wind power generation and to reliably supply the electricity consumption of all sectors. This presents an opportunity for embedding value chains, which has been explored in the South African Renewable Energy Masterplan. Localised manufacture of battery components can be supported by a repurposing of the 12I tax incentive for Greentech manufacturing. [13]

By 2040, between 5 and 10 GW of gas turbines will be built in all scenarios, mainly as backup capacity for peak loads rather than for baseload supply. This raises concerns about the financial viability of this new capacity. It is recommended, as does the Energy Council [14], to promote dispatchable capacity for system stability where (imperfect) market signals alone would not be sufficient to ensure bankable projects.

The total gas consumption of all sectors is at around 40 TWh by 2030 in all scenarios and peaks at 45 TWh by 2040 in the NZ scenario. However, by 2050, natural gas is replaced by synthetic green Power-to-Gas in the main NZ and NZEE scenarios. The gas consumption of our analysis is low compared to other studies, such as the NBI study. The NBI study expects a temporary consumption of 94 TWh in 2040 (around 50 TWh more) [15]. The use of gas for gas-fired power plants depends on the assumed electricity consumption, gas import prices, ramp-up of renewables, and availability of the transmission grid. However, based on the findings and from a national perspective, the currently planned LNG import capacity in Richards Bay of 5 million tonnes (or 77 TWh) is needed. With regard to the technical and economic feasibility of a new fossil gas import and pipeline infrastructure, the time-limited utilisation of gas in the NZ and NZEE scenarios is a challenge. Supply contracts and any planning should be limited to a time frame of 20-25 years, taking into account a net-zero pathway. Furthermore, the switch to synthetic gas should be planned from today onwards.

With regard to PtX, the scenario and sensitivity analysis show that under the emission reduction targets defined for the default net-zero scenarios, synthetic methane is seen as necessary by the model. However, the need and the timing for synthetic and green PtG to meet certain emission levels by 2050 or beyond apparently depends on system-wide or sector-specific CO_2 targets. The slightly higher CO_2 emission level for NZ or NZEE, assuming negative LULUCF emissions and a different fair share budget, reveals that natural gas import shrinks to 16 TWh but is still present. Clarity regarding sector-specific CO_2 targets for 2050 is needed to facilitate planning.

Increased support for the accelerated expansion and integration of renewable energies and battery storage is necessary.

Recently, progress has been made regarding the reformation of the electricity market and the implementation of policy support for renewables, as tracked in the recent progress report of the Energy Action Plan by NECOM [16]. Examples of progress include the removal of the licensing threshold for private power generation, the establishment of a one-stop energy shop to facilitate permits and the initial establishment of a national transmission company (ESKOM NTCSA). These activities should be continued and improved. To further support and accelerate the expansion of solar, wind and batteries the following actions are recommended:

- Fast-track public procurement processes for renewable energy sources (RES) and battery energy storage (BES) to meet NZ and NZEE targets before a functioning electricity market is established, particularly through streamlined approvals and financing support.
- Establish a competitive electricity market and address potential market failure due to market power or hurdles to participate in the market.
- Use auctions and other incentives for renewable projects, such as tax incentives, to encourage capacity expansions in specific zones with available grid capacity.
- Promoting private investment in generation capacity by informing on the removal of the licensing threshold and improving the fast-tracking of approvals in a one-stop shop, which was established in June 2023.

- Improve grid connection capacity in the Cape regions to support the connection of the renewable energy procurement programme's capacities.
- Extension of the programme for controlling the demand for distribution, taking into account electrolysers and battery-electric vehicles.
- Implement the framework of a national wheeling framework to enable the non-discriminatory usage of the transmission grid. Many will benefit from this, including PtX projects.

South Africa's potential in terms of suitable land area and resources is enormous, but major investments to strengthen the power grid's connection capacity in the Cape regions, the transmission grid and H_2 transport capacities are crucial to integrate the Tier 1 renewable regions and unlock competitive PtX production.

For this study, suitable areas with good conditions for renewable energies were identified and hourly generation profiles for wind and solar energy were created using spatio-temporal data sets. The result of this analysis of the area potential shows that the area potential for the construction of solar and wind energy plants is enormous, depending on the region, and far exceeds demand. The identified areas overlap with the Renewable Energy Development Zones (REDZs), but additional well-suited areas are seen in all regions. The REDZs could, therefore, be expanded in coordination with the TDP process. The weighted mean full load hours (FLH) per supply region ranges from 1584 h in KwaZulu Natal to 1898 h in the Northern Cape for solar PV. The weighted mean FLH per supply region ranges from 2268 h in KwaZulu Natal to 3561 h in the Hydra Cluster model region for wind. It should be noted that at a smaller scale, weather conditions could be even better, up to a FLH of around 1950 for solar PV and 4400 for wind.

However, the areas suitable for solar PV and wind are also constrained by the power grid. The latest two Generation Connection Capacity Assessment (GCCA) show that there is little or no capacity for additional capacity in the Cape regions. Furthermore, interregional transmission line capacity to the Northern Cape is limited. The latest Transmission Development Plan (TDP) [3] addresses the problem of a lack of grid infrastructure (substations). In this study, we limit the expansion of the Cape regions in the CP and NZ scenarios based on the plans in the TDP. For NZEE the generation capacity expansion in the Cape regions is not restricted, assuming accelerated investments in grid infrastructure or partly stand-alone PtX systems that are independent of the grid. In addition, in all scenarios the interregional transmission capacities are also modelled.

The model and scenario results show that the Cape regions are significantly expanded – most in the NZEE scenario, in which the capacities go beyond the current plans in the TDP. The sensitivity runs for the transmission grids show that no grid expansion would result in 10% higher energy system costs compared to an expansion of 20% relative to the current transmission capacity. Figure 99 highlights the line improvements recommended by the model. Important expansions include the connections from the North Cape region to the demand centres in order to exploit the exceptional renewable capacities in the region.

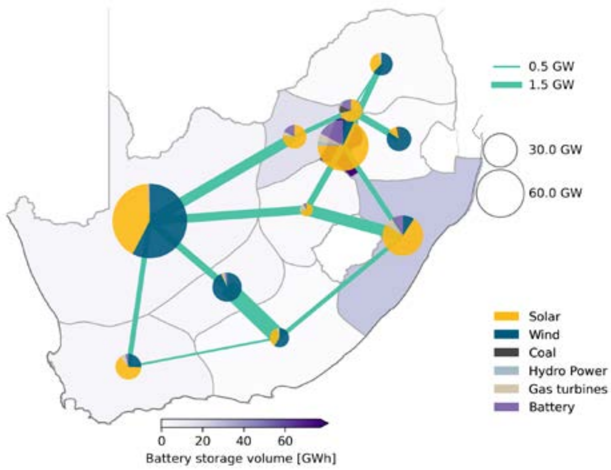


Figure 2: Map of the expanded transmission grid, electricity generation, and storage capacities by 2050 in the sensitivity NZEE-1.2 with a line volume expansion for the transmission lines of 120% compared to today's capacity.

3 Transmission capacity refers to the maximum amount of electricity that can be transported across the grid's transmission lines across regions, while generation connection capacity indicates the maximum amount of electricity that power plants can feed into the distribution grid. The generation connection capacity depends on the capabilities of the power plants, their connection agreements with the grid operator and the available substation capacities. While transmission capacity focuses on the grid's ability to carry power, generation connection capacity deals with how much power can be produced and injected into the grid.

Therefore, the grid infrastructure in the Cape region urgently needs to be improved. Furthermore, it is recommended that the research groups of the next TDP and of ESKOM take potential Power-to-X developments into account.

The expansion of the electricity grid infrastructure should be coordinated with the planning of other transport infrastructures for the other energy carriers and the new PtX fuels and feedstocks. With PyPSA-RSA-Sec, we have made a first move towards an integrated cross-sector and cross-infrastructure planning and are analysing not only electricity transmission capacities but also the necessary H_2 transport capacities. The model results show that transport capacities for H_2 are expanded and co-optimised. As illustrated in the next Figure, the Northern Cape, Gauteng, and Mpumalanga dominate with large H_2 Electrolysis capacities.

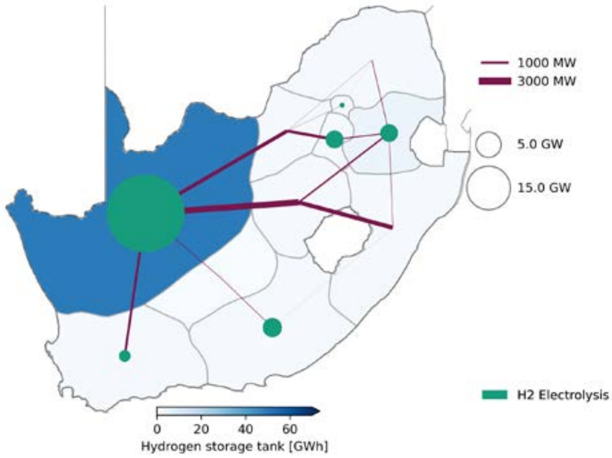


Figure 3: Map of installed hydrogen generation, storage and transport capacities by 2050 in the scenario NZEE.

According to the optimising of the model, this results in a need for H_2 transport from the Northern Cape to the industrial and densely populated regions of Gauteng and KwaZulu Natal to supply the assumed final energy hydrogen demands (e.g. for chemical industry or heavy-duty FCEV). Although the distances for H_2 pipelines are very large (e.g. Northern Cape to Free State is approx. 600 - 1000 km), the volumes with an average flow of more than 60 t/h would justify the economic viability.

A dedicated analysis and roadmap for hydrogen transport via pipeline, rail, or road from production sites to demand centres or synfuel facilities is highly recommended. This should be developed in close collaboration with Transnet, the key pipeline and rail infrastructure provider. It is recommended that relevant stakeholders participate in "Transnet Long Term Planning Framework" [17].

As South Africa and the world move towards Net-Zero emissions, the total demand of PtX fuels and feedstocks in South Africa of 3.5 – 10.5 Mt is driven by industry, international aviation and shipping, freight transport and the PtX export opportunity.

The demand for green PtX in the transport sector is driven by international aviation, shipping, and heavy-duty vehicles. Projected PtX demands range between 52 and 90 $TWhH_2$ by 2050, with key infrastructure needed along mobility corridors (N1, N2, and N3) and at the international airports of OR Tambo, Cape Town and King Shaka International. The high variation in demand is due to uncertainties in international regulatory developments for aviation and shipping, which are largely influenced by the International Civil Aviation Organization (ICAO) and the International Maritime Organization (IMO).

The industrial sector, particularly iron and steel, ammonia, cement, and chemicals, is a major consumer of green hydrogen and PtX, with projected demands reaching 45 to 62 $TWhH_2$ by 2050. It is assumed that the Iron and steel production via DRI-EAF processes using hydrogen as a reducing agent will ramp up by reviving the mothballed assets of ASMA in Saldanha, while green ammonia supports the production of fertilizer for use in Southern Africa.

PtX exports represent the largest potential driver for hydrogen demand, with potentially up to 193 $TWhH_2$ or 5.8 MtH_2 needed by 2050. Companies like Sasol, Hive, Enertrag, and the Prieska consortium are interested in large-scale production in the Northern Cape, Western Cape, Mpumalanga (Secunda) or at Sasolburg. Early export activities by the actors mentioned and by others would catalyse further capacity expansions and export growth, though these would require substantial policy support to overcome existing regulatory and financial hurdles and risks.

28 to 70 GW of H_2 electrolysis, plus large capacities for synthesis processes and CO_2 capture, will be required to produce the volumes of PtX for domestic use and export by 2050.

The installed hydrogen generation capacity reaches 0.5 to 0.6 GWel in the scenarios CP and NZ. It increases to 9.1 GWel by 2040 and 17.2 to 28.3 GWel (65% higher in NZ than CP) by 2050. In the NZEE scenario, the ramp-up of hydrogen capacity is much more ambitious. By 2030, NZEE achieves 5.8 GWel of installed capacity. This capacity increases drastically to 30.6 GWel in 2040 and more than doubles by 2050, reaching 69.7 GWel. The installed hydrogen capacities in 2040 and 2050 are 3.4 to 2.5 times higher than in NZ.

The NZEE scenario requires a substantial ramp-up of hydrogen electrolysis capacity. This is coupled with the need for infrastructure, supportive policies and significant expansion in renewable capacity (396 GW in total). With the hydrogen production levels for domestic use and for export, NZEE is in line with the ambitions of the GHCS uplift scenario and the NBI net-zero study for South Africa.

Green Power-to-Liquid (PtL) fuel synthesis starts to scale significantly after 2030, mainly to meet export demands. By 2040, PtL exports reach 4.5 TWh in both CP and NZ, while NZEE targets an ambitious 45 TWh. By 2050, these export volumes increase further, with CP and NZ at 10 TWh and NZEE reaching 100 TWh (or 8.3MtFT), highlighting NZEE's emphasis on establishing South Africa as a major PtL exporter in global markets. NZ and NZEE scenarios incorporate additional green PtL production to meet CO_2 constraints, with 26 TWh allocated to supply green fuels for aviation and shipping by 2050, representing an e-fuel share of 50%.

By 2050, the NZEE scenario demands extensive CO_2 capture – 21 $MtCO_2$ from industrial processes, with additional capture from biomass and direct air sources – driven by high PtL and PtG fuel production needs.

To meet hydrogen electrolysis needs, desalination requirements rise across scenarios, with NZEE reaching 172.7 million m^3 by 2050 – over four times the CP demand. This substantial water use reflects NZEE's ambitious hydrogen and export targets but remains significantly below the historical water consumption of coal-fired power plants.

While the net-zero and the least-cost export-oriented net-zero paths for the energy system in South Africa exploit the industrial and natural potential to the highest degree, these paths also involve the highest investments, challenges and risks that need to be addressed.

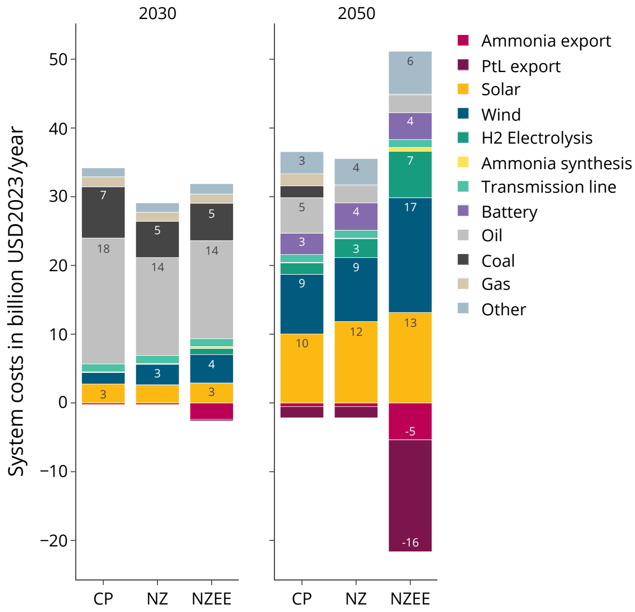


Figure 4: Annualised system expenses (+) and revenues via export (-) for CP, NZ, and NZEE in USD2023[4].

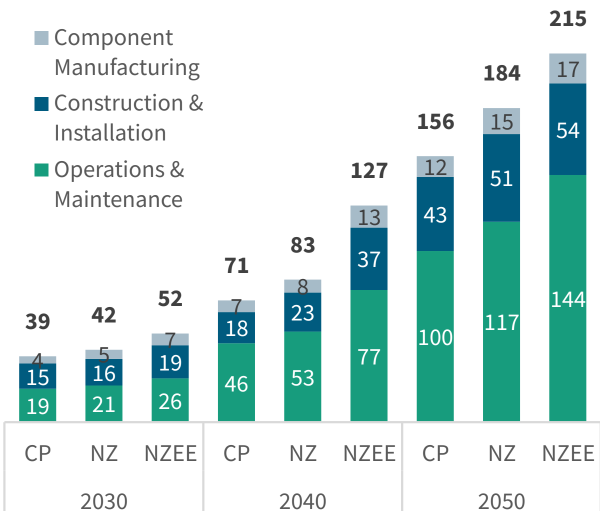


Figure 5: Indicative estimation of potential job creation effect in thousand jobs per year (kjobs/year) for operation and maintenance, construction and installation and component manufacturing for each time horizon and scenario.

Under the assumptions made, the pathways of NZ and NZEE result in the lowest net system costs per year, considering annualised capital expenditure, operating expenditure and export revenue.

The energy system evolves from a fuel-dominated cost structure in 2030, reliant on oil and coal, to a CAPEX-intensive structure by 2050, with significant investments in wind, solar, and H_2 electrolysis technologies. By 2050, total system expenses in NZEE reach 51.2 billion USD – higher than CP and NZ – offset by export revenues of 21.6 billion USD from ammonia and PtL fuels, showcasing the revenue potential of large-scale hydrogen exports.[4]

Due to these high export revenues, NZEE becomes the most cost-effective scenario by 2050, despite being slightly more expensive in 2030. The difference between 2030 and 2050 indicates that the higher proportion of higher-quality PtL fuel exports is more profitable for South Africa than ammonia exports. Under our price and global PtX market assumptions, the competition in the ammonia export market is high making it hard for South Africa to compete by 2030. Conversely, the competitive advantage of South Africa in the PtL export market is significant. Two significant advantages are (1) the available Carbon Capture and Usage options beyond the cost-intensive Direct Air Capture technology, which are not available for non-industry heavy exporters and (2) the available expertise and facilities for the Fischer-Tropsch synthesis of fuels, which were taken into account here by reducing technology costs. Further geographical advantages are a long coastline for seawater desalination and existing global shipping routes from the ports in South Africa.

Beyond the net system cost advantages of the ambitious net-zero scenarios (NZ and NZEE), the high-level estimation of job effects also shows higher job creation potential in the renewable sector in the range of 184 to 215 and lower relative energy generation costs. The expansion and development of a large seawater desalination industry will provide bonus effects for the local population - without relevant additional costs compared to the costs of H_2 production or the energy system.

Despite the arguments in favour of NZEE, several risks and challenges beyond the already mentioned capacity expansion requirements exist and must be addressed.

Other infrastructure challenges relate to the scenario's reliance on new export infrastructure such as the planned Boegoebaai port, the need to improve basic infrastructure such as roads in these new industrial regions, and the associated uncertainties about construction times of those infrastructure projects.

As mentioned, many sources for capturing and using CO_2 (CCU) positions South Africa competitively in the global PtX market. With regard to these by-products, it will be important to keep an eye on the development of the regulatory framework in South Africa and with trading partners in the future.

Concrete recommendations regarding CCU are:

- In order to achieve the ambitious export targets which are possible by 2040, early planning must be a priority for CCU infrastructure as well as carbon transportation pipelines, which should be built during the 2030s.
- Negotiations with the EU to amend the RED & DA on the free allocation of electrons should also be prioritised to allow e-SAF produced at a transitioning Secunda site to be eligible under the RFNBO regulations.
- An international book and claim system for e-SAF would enable the use of the fuel produced at secunda to enter the global aviation market with minimal need for transportation.

Clarity on South Africa's 2050 net-zero target and global targets for international shipping and aviation is important to avoid stranded investments and socio-economic problems.

---

4 The currency exchange rate between USD2023 and ZAR2023 is 18.4527

South Africa submitted its updated Nationally Determined Contribution (NDC) for 2030 in September 2021 [92]. The communicated conditional target range for greenhouse gas emissions is 350-420 $MtCO_2e$ by 2030 incl. negative LULUCF or an estimated 366-436 excl. LULUCF according to Climate Transparency [93]. In addition to the NDC target range for 2030, the President has communicated the commitment to net-zero by 2050 and recently signed the Climate Change Bill into law. This lays the foundations for ambitious long-term CO_2 reductions. However, the CO_2 budget and the specific policy target value for fossil, energy or sector-related CO_2 emissions in 2050 are still unclear or uncertain. Uncertainty factors include the development of LULUCF emissions, the trend in waste and agricultural emissions and the options after 2050.

This study explores the impact of lower and higher limits of 35 $MtCO_2$/year, 50 $MtCO_2$/year and 65 $MtCO_2$/year by 2050 via a sensitivity analyses. These variations aim to assess the "last mile" reduction efforts needed and highlight potential risks of stranded assets from fossil-based investments as the energy system transitions.

The results of the sensitivity analysis show, that lower CO_2 targets (35 $MtCO_2$) significantly increase renewable energy capacity needs, driving additional wind and solar installations in both NZ and NZEE scenarios. For instance, NZ-35$MtCO_2$ demands 332 GW, a 9.2% increase over the main NZ scenario, while NZEE-35$MtCO_2$ needs 436 GW, marking a 10.1% rise above NZEE. Hydrogen electrolysis capacity similarly scales, reaching 44 GW in NZ-35$MtCO_2$ – over 57% higher than the main NZ scenario. Conversely, a relaxed CO_2 target (65 $MtCO_2$) reduces these needs, with NZ requiring only 269 GW of renewables and 17 GW for hydrogen, demonstrating the direct influence of CO_2 targets on capacity planning.

Tighter CO_2 targets (35 $MtCO_2$) drive complete reliance on synthetic fuels for remaining liquid fuel consumption, especially for sectors like shipping and aviation. In NZEE-35$MtCO_2$, synthetic Power-to-Liquid (PtL) demand for export reaches 178 TWh, almost doubling capacity at facilities like Sasol Secunda. In contrast, with a 65 $MtCO_2$ limit, fossil fuel imports persist, covering residual demand for industrial processes and electricity, highlighting the shift from fossil dependence to synthetic fuels as emission targets tighten.

Achieving lower CO_2 emissions results in higher annualized expenditures, underscoring the cost of final emission reductions. For instance, NZ-35$MtCO_2$ incurs annualized costs of 38.7 billion USD2023 (+8.7% over NZ), while NZEE-35$MtCO_2$ reaches 55.8 billion USD2023 (+8.8% over NZEE). Despite these costs, stricter targets enhance South Africa's resilience, reducing fossil fuel import dependence, stabilizing against price fluctuations, and positioning the country to capitalize on green exports under international carbon standards.

Therefore, it is recommended to support future research on a clear definition of sectoral CO_2 targets for 2050.

While green industrialisation in South Africa will increase the competitiveness of the economy in climate-compatible markets, supportive policies are needed to leverage the potential.

The decarbonisation of industry and the PtX fuels and feedstocks required for this are no longer necessary only for a net-zero path in South Africa, but for the development of a sustainable economy. The so-called green industrialisation can enhance South Africa's economic resilience in climate-compatible markets by boosting its competitive edge in green technologies and value chains.

This aligns with South Africa's Just Transition Framework, which prioritises sustainable industry development and the gradual shift from carbon-intensive production. However, support is essential in order to take full advantage of these opportunities. Policies for an inclusive and successful transition are described in a comprehensive policy brief by Trade & Industrial Policy Strategies [18], as well as the strategies (SAREM [19], Just Energy Transition Plan [20], Hydrogen Society Roadmap for South Africa [21]) already mentioned. The recommendations are:

To build a robust local supply chain, policies should incentivize domestic manufacturing of renewable and green hydrogen components, as proposed in the South African Renewable Energy Masterplan (SAREM). Additionally, workforce development through Technical Vocational Education and Training (TVET) colleges and the Sector Education and Training Authorities (SETAs) should focus on emerging technical roles, such as renewable energy technicians and GH_2 specialists, to equip South Africans with skills for a green economy.

Key policy recommendations to support the green industrialisation, as also described in [18], are:

- Establish a green public procurement policy prioritizing local, sustainable products, such as renewable energy components, electric vehicles, and sustainable building materials, to stimulate domestic green industries.
- Introduce dedicated incentives for manufacturers adopting green processes or producing green technologies, including preferential financing and tax benefits for companies contributing to the renewable energy, battery, and electric vehicle sectors. An example of the support of local manufacturing is the tax incentive 12I for Greentech, proposed by the South African Renewable Energy Masterplan to build domestic value chains for energy storage technology.
- Establish or improve designated green industrial zones with specialized infrastructure, tax incentives, and streamlined regulatory processes.
- Gradually phase out fossil fuel subsidies and reallocate these funds toward green industrial policy tools, including tax incentives for renewable energy projects and concessional loans for green technology development.
- Increase funding for R&D in renewable energy, battery storage, and green hydrogen production. Establish partnerships with the private sector to support the commercialization of green innovations.

Promote the development of interlinked roadmaps for national energy and Power-to-X planning

To effectively plan the national energy generation, transmission and Power-to-X (PtX) fuels and feedstock developments, it is essential to establish a comprehensive, interlinked strategy and policy roadmap that integrates strategies for electricity generation, transmission, and related infrastructure. This roadmap should include key elements for PtX value chains, recognizing their cross-cutting impact on land, water, energy, natural resources, logistics, and finance. Coordinated efforts among various government departments, public sector institutions, and private sector stakeholders are essential for a seamless value chain.

The roadmap should align and interlink existing plans such as the Grid Connection Capacity Assessment (GCCA), Transmission Development Plan (TDP), and the Integrated Resource Plan (IRP) with hydrogen-focused strategies like the Green Hydrogen Commercialisation Strategy. This integration will ensure a cohesive approach to grid and transport infrastructure development, supporting both hydrogen projects and the broader renewable energy transition in South Africa.

Track global developments and continuously update roadmaps

The PtX market, PtX and hydrogen market regulation, auction designs and the development of green technologies are currently subject to high dynamics. For instance, the report describes the cost dynamics of H_2 electrolysers, solar and wind. Furthermore, it is outlined that the Export price assumptions are uncertain. It is also unclear when the global demand pull for PtX will happen. Against this background, it is necessary to continuously track global developments and update the relevant roadmaps.

Future research is needed to dive deeper into details on transport routes and infrastructure, potential synergies between neighbouring countries in SADC, different sectoral demand developments, and further aspects.

- Higher spatial resolution (more than 11 regions) combined with improved representation of transporting routes and infrastructure for transporting hydrogen, methane, liquified fuels, water, ammonia, CO_2, biomass water, ammonia, CO_2, biomass.
- Improve the representation of technology constraints, such as the selectivity of the Fischer-Tropsch process or unit commitment constraints on a regional level.
- Extend the analysis of the targeted production of PtX export products to other PtX products such as, for example, green DRI.

- Analysis of the potential of cooperation between SADC countries using a multi-national model for the SADC regions.
- Focus on short-term time horizon with predictive assumptions on the market ramp-up of renewables and power-to-X projects.
- Assessment of further transport and industry demand sector developments (nationally and region-specific).
- Detailed socio-economic assessment, what impacts on a just transition.
- Integrate PtX scenarios and roadmaps into the next Transmission Development Plan.
- Update and adapt South African Hydrogen roadmaps on a regular basis.
- Facilitate further research and sensitivity analysis by promoting open energy data and open-source models.
- Detailed energy system analysis should become a key pillar of future strategies.

1 Introduction

1.1 Background

South Africa (SA) is in a crucial phase, facing significant challenges related to energy security and the global shift towards a net-zero economy. The economy and population have suffered frequent power outages for over a decade, with more than 16 TWh of unserved energy due to load shedding experienced in 2023 [1]. The public electricity utility is in an uncertain financial situation, which could delay electricity grid investments required to integrate renewable energies [2]. Additionally, the share of fossil fuel imports increased from 35% in 2020 to 61% in 2023 [3]. With the methane-rich gas from Mozambique expected to be depleted by 2026, this supply will need to be replaced by LNG imports [4]. This situation makes SA more vulnerable to global fossil price shocks. Investments in new infrastructure, generation capacity and detailed planning are thus essential to address the current high level of risks and uncertainties.

Adding to these pressures, the global shift towards net-zero presents substantial risks to SA's carbon-intensive industries that have long been powered by coal. Currently, coal-based electricity generation constituting 80.1% of total annual electricity production [5], the Fischer-Tropsch crude production of up to 150.000 barrels per day (or 7.5 – 7.7 Mtpa) via coal- and gas-to-liquid [22], and further coal-reliant industries are collectively making SA one of the top 20 most carbon-intensive economies globally [6]. As international markets and key trading partners adopt stricter low-carbon policies, South Africa's economic stability and competitive edge are increasingly at risk. Several major export markets, including the EU, USA and China, have set net-zero targets. The EU has launched the first phase of a carbon border tax mechanism, which, from 2026, will impose a CO_2 levy on products imported into the EU from countries that do not have a CO_2 price equivalent to that of the EU.

However, SA has great potential to unleash a transformation of its energy landscape which could drive economic growth, improve energy security, and enable new export opportunities to international markets. Globally, government strategies have emphasised the pivotal role of green Power-to-X (PtX) molecules, fuels and feedstocks in transforming the industry, transport, and mining sectors and balancing power systems with high wind and solar PV penetration. According to global net-zero and hydrogen trade studies [7–9], it is estimated that between 150 to 200 million tons per annum (mtpa) of hydrogen and its derivatives will be transported over long distances and across borders depending on various scenarios and assumptions regarding hydrogen adoption, infrastructure development and policy support. Of this traded volume, around 45% would be shipped [9], resulting in a market volume for the shipping portion of internationally traded hydrogen of 68 to 90 million tonnes annually. South Africa is well-positioned to become a key player in the emerging green PtX markets by leveraging its natural and industrial strengths. On the supply and manufacturing side, the country is well-positioned due to its abundant suitable land area, world-class solar and wind resources, expertise and existing assets for synthetic Fischer-Tropsch crude production, and a mature iron and platinum mining sector. In terms of local demand, previous studies highlight significant regional offtake potential for green PtX in hard-to-abate sectors such as the iron and steel industry, as well as its current applications as feedstock in various industries, and in aviation and shipping. According to South African studies the projected local PtX demand could become significant by 2030 [10, 11] and will then contribute to the development of business cases and the scaling up of PtX projects. The resulting economies of scale will contribute to achieving cost competitiveness for both local and exported hydrogen. To enable the large-scale implementation of green PtX for both export and domestic applications, however, it is crucial to expand renewable capacities and to invest in national grid and logistical infrastructure.

Latest studies considering the hydrogen opportunity up to 2050 for South Africa

Further studies focussing on or including the hydrogen opportunities for South Africa include the Green Hydrogen Commercialisation Strategy [10], the Hydrogen Society Roadmap for South Africa (HSRM) [21] and the NBI-BUSA-BCG South Africa's Net-Zero Transition study (NBI) [15]. In addition, important assessments with a regional focus were carried out to support the GHCS and the Society Roadmap, such as the South Africa Hydrogen Valley Report [11] and the Northern Cape Green Hydrogen Masterplan ($NCGH_2$) [23].

The Green Hydrogen Commercialisation Strategy (GHCS) was released for public comment in 2022, focusing on six key pillars: export potential, stimulation of the domestic market, development of local industrial capabilities, financing, socio-economic development, and policy and regulatory support. The strategy quantifies import volumes for the main net importers of green hydrogen (GH) by 2050, with Europe accounting for 11 – 15 mtpa, the UK for 0.7 mtpa, Japan for 5-10 mtpa, and South Korea for 1.2 mtpa. Based on an analysis of global net exporters, South Africa's target export volume is set at 1.9 mtpa in the base scenario of the strategy. For domestic consumption, a range of 2 to 3 mtpa (including bunkering) is outlined, with a potential upper limit of 6 mtpa. In the base case, 1.9 mtpa is allocated for domestic use, because it is unclear whether higher volumes would be cost-efficient. To achieve these production levels, the strategy calls for 56 GW of installed solar capacity, 24 GW of wind capacity, and 41 GW of electrolyser capacity to meet both export and domestic demand. In an uplift scenario, South Africa's hydrogen production level increases to 7 mtpa by 2050. However, for the country to be competitive in higher-volume exports to the EU, it will need to contend with strong competition from Morocco and others. According to the report, the forecasted green hydrogen prices in these competitive markets are expected to range from \$2.94 – \$3.24/kg in 2030, dropping to \$1.18 – \$1.47/kg by 2050[5]. To reduce costs throughout the value chain and improve competitiveness and efficiency, cooperation with Namibia to advance the development of GH infrastructure, as well as strong support from the government, public sector institutions, and private sector partners, will be crucial. [10]

The South African Hydrogen Society's roadmap was developed prior to the GHCS in 2021. The roadmap study describes the current energy landscape and relevant value chains associated with hydrogen opportunities. It integrates different aspects including platinum group metals (PGMs), infrastructure, and the principles of a just transition. The roadmap is supported by more detailed analyses for catalytic projects. Key projections from these flagship projects include the deployment of 10 GW of electrolysis capacity in the Northern Cape and 1.7 GW in the Hydrogen Valley regions by 2030, with an estimated annual production of 500,000 tons of hydrogen by that time. This is expected to generate at least 20,000 jobs per year by 2030. On the demand side, the use of hydrogen is anticipated in fuel cell buses and trucks, hydrogen or ammonia-fired power generation turbines, and various industrial applications. [21]

The Northern Cape Green Hydrogen Masterplan aims to establish a large-scale green hydrogen zone with 40 GW of electrolyser capacity by 2050, leveraging its vast potential of solar (11,400GW, capacity factor 26%) and wind (846GW, capacity factor 37%) resources. Key infrastructure plans are the Boegoebaai port, rail project, SEZ (Special Economic Zone), and pipelines. As an initiating investor, Sasol, is considering a 4.8 GW electrolyser and 10 GW of renewable energy in the zone. Additionally, the Masterplan aims to address South Africa's energy crisis and to enhance grid stability. It is estimated that the 40 GW ambition could supply around 15 TWh of surplus energy to the transmission grid annually. Additionally, reducing electrolyser usage during peak times will contribute to load balancing. [23]

5 The cost assumptions in the GHCS study are based on 2021 sources. Since then, it has become clear that hydrogen costs are likely to be higher for a longer period of time and that inflation has further increased the values. (see [24]).

The comprehensive NBI study [15] on South Africa's net-zero transition outlines a pathway for decarbonizing the country's economy by 2050, focusing on several key sectors such as power, mining, petrochemicals, and transportation. The study quantifies that by 2050, 190 GW of renewables capacity will be necessary to achieve net-zero and to meet growing power demand. An additional 170-200 GW of renewable energy is required to meet an annual green H_2 demand of 8.5 – 9.5 million tons (of which 3 to 4 mtpa for export) by 2050, necessitating an overall annual rollout of 18 GW of renewables starting in the 2040s. The study further states that natural gas will play a temporary role, with consumption of up to 340 PJ p.a., but it must be phased out by 2050, with gas turbines built now being H_2-ready. International support will be critical for South Africa to meet these ambitious targets. The estimated capital and operational expenditures for the renewable power system are about 300 billion ZAR p.a. which is significant. However, it is estimated that this investment is still more cost-efficient compared to the future costs of maintaining the current power system.

Latest capacity expansion planning for South Africa

Capacity expansion planning for national electricity and energy systems refers to the strategic process of determining the optimal expansion of energy generation, transmission, and storage infrastructure over time to meet growing energy demand while achieving policy objectives such as decarbonization, energy security, and cost-effectiveness. In general, capacity expansion planning is challenging due to the uncertainties of energy markets, evolving technological advancements, policy changes, and shifts in energy demand patterns. The integration of variable renewable energies into all energy sectors is making the task even more complex. To analyse this complexity, scenarios are defined, and large-scale computer models are used.

In the South African context, the latest capacity expansion planning studies focused on the electricity system until 2030 and addressed critical challenges like frequent load shedding, aging infrastructure, and the necessity to transition towards more sustainable and reliable energy sources in line with national development goals and international commitments to reduce greenhouse gas emissions.

Figure 6 presents the capacity expansion plan of the Integrated Resource Plan 2019. Comparing the numbers of the IRP 2019 with the actual expansion values that were realised up to 2022 (displayed in Figure 7) illustrates the uncertainties and the complexity of capacity expansion planning. Distributed PV additions significantly exceeded IRP 2019 expectations, while other capacity additions, such as wind, grew less than planned due to delays in the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP).

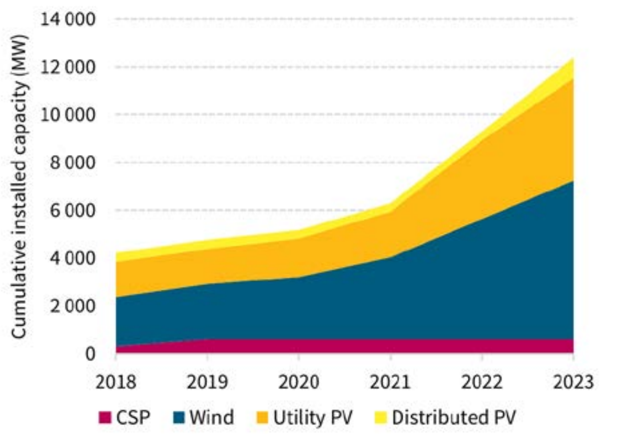


Figure 6: IRP 2019 capacity expansion plan for South Africa [1].

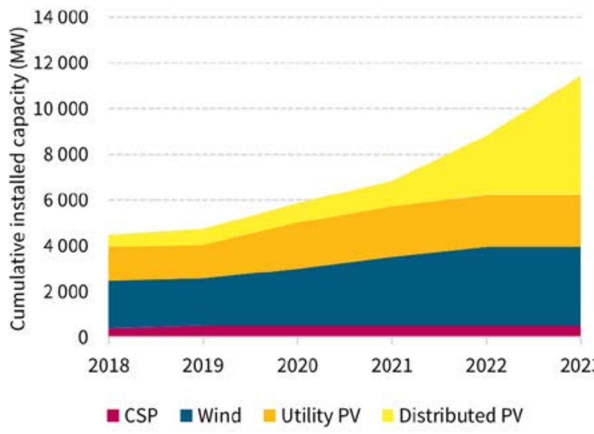


Figure 7: Actual capacity expansion seen in South Africa [26], [4].

Looking ahead, the capacity expansion figures for South Africa also differ significantly between the various published studies and policies in terms of expected or cost-optimal capacity expansions by 2030. Figure 8 illustrates the differences in cumulative capacity up to 2030 for wind, solar PV, storage, gas & diesel and coal published by TDP, IRP, JET-IP and Meridian Economics studies.

These differences in the plans for the expansion of generation capacities are due to different input data, methodological decisions, external influences, scenario assumptions and system boundaries. This underlines the importance of a detailed description and reasoning behind assumptions including input data, modelling approaches and spatial resolution, resource availability, demand forecasts and technology costs, which are presented in the following chapters. Parameter uncertainty is further explored through the development of a range of scenarios to capture the option space and identify trade-offs.

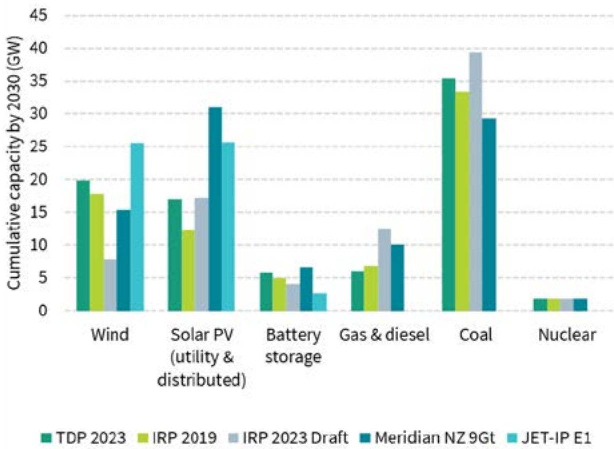


Figure 8: Cumulative installed capacity by 2030 published by the TDP [25], IRP2019 [26], Draft-IRP2023 [27], JET-IP [20] and Meridian Economics [28].

1.2 Scope and Objectives of this Study

Most of the recent South African power system or energy scenario studies focus on the ten-year horizon to 2030/32, motivated by the energy crisis and the need to plan investments in the short term. Such plans include the Integrated Resource Plans (IRP) from 2019 [26], the draft IRP from 2023 [27], Transmission Development Plan (TDP) [2], and the Just Energy Transition Investment Plan (JET-IP) [20]. Nevertheless, analyses are needed to explore the decision space for achieving South Africa's Nationally Determined Contribution (NDC), which sets an ambitious target of 350-375 Mt CO_2eq in 2030 with net-zero by 2050, and to assess the level of support required within the context of existing policies and measures. The latest research lacks a link between long-term, quantitative, high-resolution scenarios for a net-zero energy system in line with the NDC and the short-term requirements and plans to solve the country's energy crisis. In addition, there are uncertainties surrounding grid expansion and sectoral decarbonisation, particularly in relation to direct electrification, the production of renewable hydrogen and its derivatives (PtX fuels) and their export potential. The implementation pathways of decarbonisation strategies have significant implications for South Africa's energy system. With a holistic and systemic approach, this project aims to model and analyse the development of the existing power and energy system from 2030 to 2050 to achieve decarbonisation targets and facilitate defossilisation. Comprehensive energy system modelling of the South African energy system at a high spatial and temporal resolution, capturing its interaction with both electricity and molecule supply and demand, is required. In general, such energy system modelling approaches utilise simulation and numerical optimisation software to evaluate various capacity and technology combinations for meeting energy demands. The modelling process involves optimising these combinations to achieve emission reduction targets at minimal cost while ensuring the security of the energy supply.

To meet the requirements and scope described, a key aspect of this project is the development of a versatile, sector-coupled [6], open-source capacity expansion optimisation model for the time horizon from 2030 to 2050. The model represents the techno-economic renewable and PtX supply potentials at high spatial-temporal resolution while also considering electricity transmission infrastructure. The focus is to identify the capacity requirements needed to achieve defossilisation targets by integrating renewable energies in techno-economically optimised scenarios, highlighting how and where direct electrification, green hydrogen, and PtX fuels can contribute to carbon neutrality.

6 A sector-coupled model refers to an energy system model that integrates multiple energy sectors – such as electricity, heating, transport, and industry – as well as the conversion (e.g. Power-to-X), storage and transport infrastructure options of these sectors. The purpose of sector coupling is to capture the interactions and synergies between the hourly operation and yearly investments in these sectors, enabling a holistic optimization of energy flows, cross-sector flexibility utilisation and defossilisation strategies. This contrasts with traditional sector-specific models, which often consider sectors in isolation.

Furthermore, the study at hand considers the main limitations of the short-term 2030 horizon to understand how long-term targets (2050) translate into short-term priorities or challenges. The developed energy transition pathways and scenarios can be used to inform ongoing and future policy and expert discussions on this subject, helping to explore uncertainties and identify critical enablers for a cost-effective transformation. This will support mid- to long-term planning efforts for a resilient transformation of South Africa's energy system, ensuring alignment with the country's climate ambitions.

To summarise, the **key objectives** of this project are to:

- Identify and fill relevant knowledge gaps with a focus on PtX in existing transformation studies.
- Develop coherent scenario designs through dialogue with key South African stakeholders.
- Develop an open-source model of the South African energy system for further studies.
- Identify and evaluate promising pathways for the expansion and utilisation of renewable energy and PtX for South Africa.
- Derive insights for South Africa's long-term energy and defossilisation strategy.

1.3 Structure of this Report

The remaining chapters of this report are structured as follows. Chapter two sets out the methodology and data, providing details regarding the data collection and the energy system model used. Subsequently, in chapter three the report presents the scenarios and sensitivities, beginning with an overview of the scenario narratives developed in the stakeholder process and then detailing the individual dimensions of each scenario. This is followed by a presentation of the results of the modelled pathways in chapter four, which includes an analysis of the outcomes of the different scenarios and an examination of their implications for the energy system. The report concludes with a summary of the key results and suggestions for future research in chapter five. The report is supplemented by references and appendices that provide additional data, methodologies, and stakeholder insights.

2 Modelling and Assumptions

2.1 General Paradigm

In capacity expansion planning and optimisation exercises it is crucial to account for country-specific factors and practicalities, including availability of various technologies, construction capabilities, grid limitations, import or export capacities and logistical constraints- all while considering emissions reduction targets for the future. With this in mind, the data collection and modelling approach for the project was founded on existing policies and plans developed in South Africa. Through leveraging existing policies and plans, the modelling process could be streamlined to ensure alignment with regulatory frameworks, fostering coherence and synergy between the project objectives and overarching government priorities, while allowing the project team to focus on refining specific aspects of the model relevant to the project's objectives. In addition to this, conformity with national strategies and regulations enhances the project's credibility, resilience, and effectiveness while promoting cooperation and support from stakeholders.

The Just Energy Transition Investment Plan (JET-IP, 2022) [20], Integrated Resource Plans (IRP2019 & draft IRP2023) [26, 27], Transmission Development Plan (TDP, 2022 together with GCCA, 2024) [25, 29, 30], hydrogen roadmaps and strategies [10, 21], Green Transport Strategy for South Africa (GTS, 2018 – 2050) [31] and the Draft Post-2015 National Energy Efficiency Strategy (NEES, 2016) [32] were considered in detail (see Figure 9). Public datasets generated and published by national institutions in South Africa were screened and utilised to prepare the energy system model input data. Through alignment with existing policies, plans, and input assumptions, the project team has been able to build on work carried out in previous studies while contributing to current modelling work for analysing defossilisation pathways for South Africa.

The JET-IP, released in 2022, serves as an important framework for implementation of South Africa's Just Energy Transition. The JET-IP outlines the scale of investments required to achieve South Africa's 2030 NDC target with a net-zero CO_2 goal by 2050 through the inclusion of an overall GHG budget over the period 2021-2050. Due to the absence of an updated Integrated Energy Plan (IEP) and the ongoing revision of the IRP 2023, the JET-IP served as the primary reference for gathering data and modelling assumptions, supplemented by publicly accessible data from Eskom, the University of Cape Town (UCT) [1, 25, 26, 30, 33, 34] and domestic capacity expansion studies [28, 35]. Additionally, assumptions sourced from global and continental references, including projections from the International Energy Agency (IEA) [36, 37] and geospatial data sets from the likes of ERA5 and the World Port Index [38, 39] were used.

Figure 9: South African energy plans and policies. Illustration based on [10, 20, 21, 25–27, 30–32].

The energy system analysis was conducted using the Python package for Power System Analysis (PyPSA). To ensure consistency with prior research for South Africa, an existing PyPSA model of the electricity system was used as the basis for the modelling work of this study. The PyPSA model, PyPSA-RSA, an open-source electricity system model designed for South Africa, has been used in various studies for national energy planning [40]. Using an open-source model enhances transparency, traceability and facilitates scientific cooperation and further analysis. Further details on the model and the data prepared for the study are described below.

2.2 Model Overview

The project team joined the collaborative PyPSA community, leveraging recent advancements initiated by the Meridian Economics team in developing the PyPSA-RSA model [40–42]. PyPSA was chosen for its comprehensive modelling capabilities across different scales of energy systems. It incorporates generation, storage, transmission, and conversion technology components for various energy carriers and non-energy commodities. Additionally, PyPSA is designed to be modular and extensible. Therefore, it could be customised according to the project's specific requirements. The software generally uses linear optimisation to find a least-cost investment and dispatch of assets to meet expected energy and non-energy demands while considering restrictions on annual expansion and/or CO_2-budgets. Building upon prepared input data and the existing model features of PyPSA-Eur and PyPSA-Earth-Sec [43, 44] (see overview Figure 10), a cross-sector expansion planning version PyPSA-RSA-Sec was developed. The model and the data are open source and can be downloaded and used in accordance with the specified licences [7].

---

7 The code, the licences, together with an explanation of how the required input data can be downloaded, is provided here: https://github.com/ljansen-iee/pypsa-rsa-sec

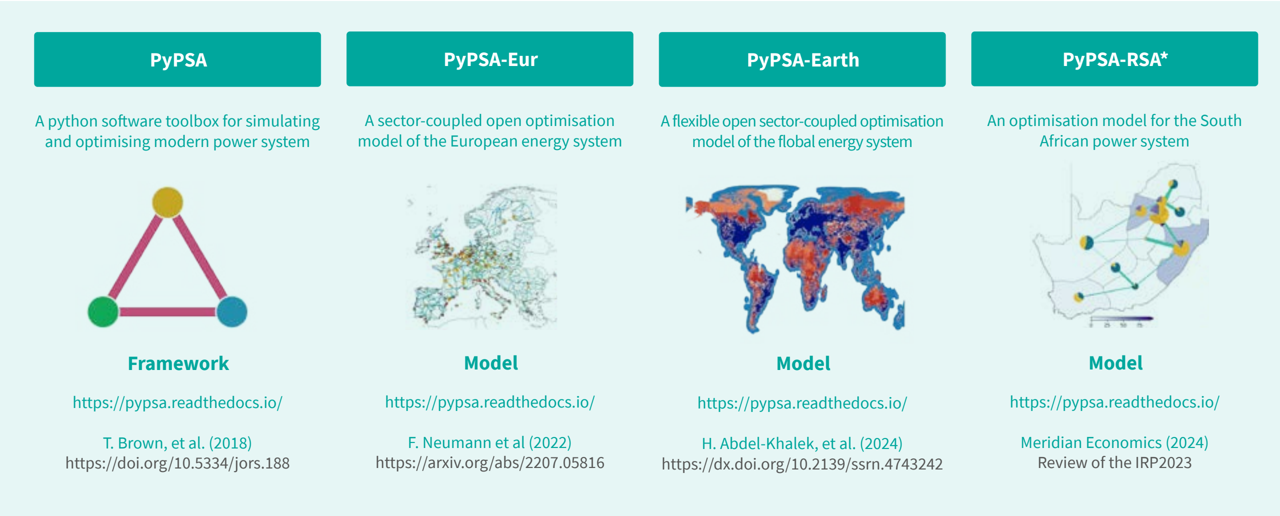


Figure 10: The PyPSA software toolbox [42, 45, 46] and existing PyPSA power and energy system models [28, 41, 43, 44, 47]. Own illustration based on the overview on pypsa.org.

The model instance PyPSA-RSA-Sec simultaneously optimises operational and investment decisions for the generation, storage, transport and conversion technologies of the South African energy system, to meet the future energy and non-energy demand for each of the planning years 2030, 2040 and 2050 at an hourly resolution. Interconnections with neighbouring countries (transmission grid or pipeline) in the Southern African Development Community (SADC) region are currently not explicitly modelled and are not considered in this analysis. With regard to electricity imports, PyPSA-RSA-Sec, like PyPSA-RSA, can import a limited amount of hydropower electricity and a fixed electricity export of 10TWh is assumed.

As illustrated in Figure 11 relevant model inputs for the scope of the study include technology costs and efficiencies, fuel costs, characteristics of existing (coal-fired) power plants, capacities and limitations of the electricity transmission grid, renewable generation potentials and restrictions, technology-specific hourly profiles, final energy demands per subsector and geospatial information for the demands. Exogenous specifications are made for final and end-use industrial (based on tons produced per subsector and technology process utilised), transport (share of fuel cell and battery electric vehicles), commercial, agricultural and residential sectors. Important inputs, such as the potential areas for renewables and the corresponding profiles for those renewables, or the final energy demand projects are simulated via so called satellite models as part of this study or taken from available datasets generated by previous studies from others. Figure 12 demonstrates the link between the final energy demand projection of UCT generated by the SATIMGE modules [48] and the PyPSA-RSA-Sec model, as well as the link between the regioATNS and energyANTS used by Fraunhofer IEE [49] for the identification of renewable energy areas and for the simulation of renewable profiles. Further details on the generation of the inputs for the optimisation model are provided in the following chapters. For example, the level of detail, data sources and approach for the demand inputs is described in section 2.8. The demand quantities, which are based on previous work by the University of Cape Town for the Just Energy Transition Plan using special models, are illustrated in Section 3.5.

The numerical optimisation of the system costs is subject to technical, socio-economic, and policy constraints. One of the primary technical constraints of the model is its requirement to cover the electricity, heat (space, water, process), methane, liquid fuel, hydrogen, etc. demands of the residential, commercial, public, agricultural, industrial, mining, transport sectors, including PtX export volumes for each time step (hour) and each spatial region. In addition, the equations of the model ensure that the energy markets of the model are connected via conversion or transport technologies, that the storage systems and demand side flexibility options (Battery electric vehicles) are operated technically correctly, and that regional expansion limits or system-wide CO_2 budgets are respected.

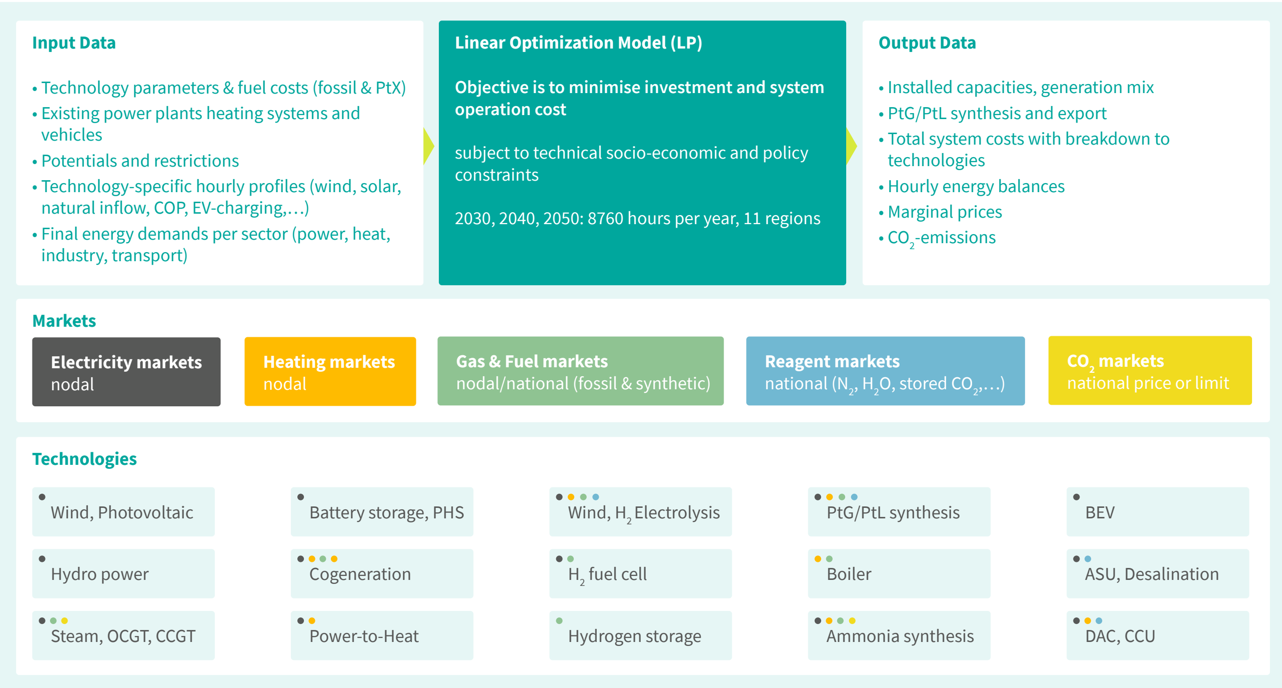


Figure 11: Scope of the cross-sector expansion system optimisation model (PyPSA-RSA-Sec) developed for this study.

Note, that specific data workflows or simulation models were used to generate the inputs renewable potentials, renewable profiles, final energy demands per sector. Own illustration.

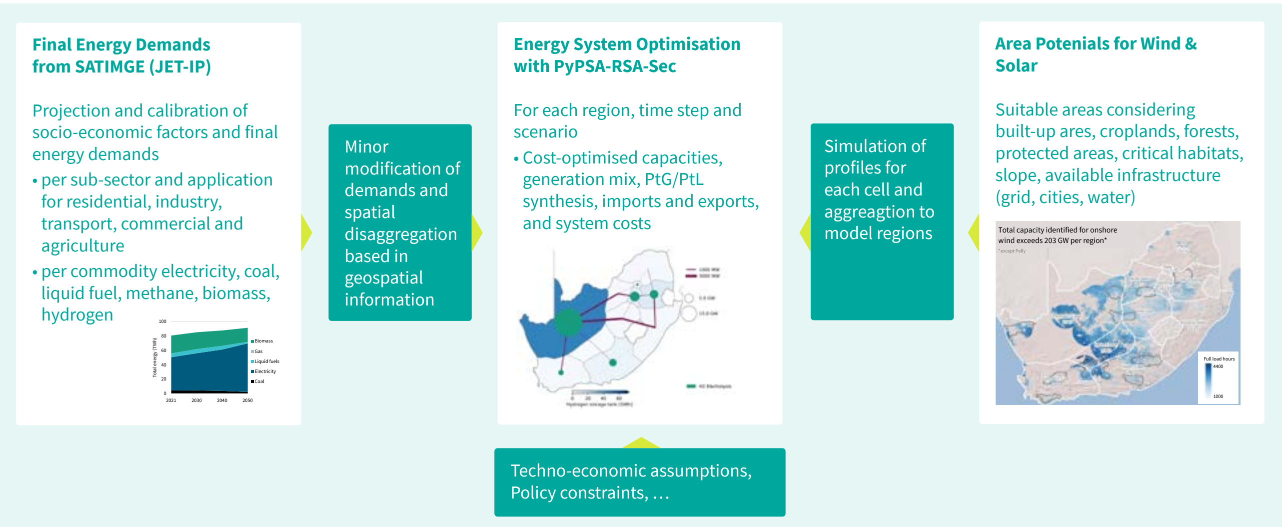


Figure 12: Link between the final energy demand projection of UCT generated by the SATIMGE modules [48] for the JET Investment Plan study and the PyPSA-RSA-Sec model, as well as the link between the regioATNS and energyANTS used by Fraunhofer IEE [49] for the identification of renewable energy areas and for the simulation of renewable profiles. Own illustration.

For this study particular emphasis was placed on the representation of PtX related technologies and energy or feedstock markets. Therefore, in addition to hydrogen, the following derivatives were also considered: synthetic green Fischer-Tropsch and methanol fuels (as an alternative to fossil petrol, diesel, kerosene and naphtha, green methane, green ammonia, nitrogen, desalinated seawater, and usable carbon dioxide (feedstock) were considered. The technology characteristics for producing Power-to-X products are detailed in the next chapter. Within the described scope, the model incorporates weather-dependent, sectoral, technical and spatial dependencies crucial for assessing the feasibility of electrification levels across sectors, and for determining hydrogen and PtX requirements.

The model outputs include installed generation, storage, transmission and conversion capacities and production decisions (e.g., for electricity, Power to Gas and Power to Liquid production and export), total system costs, hourly and annual energy balances, marginal prices for each energy carrier and CO_2 emissions. These are determined for each planning year, every hour within these years, and each scenario. As a result, the outputs are cost-optimised pathways for energy transition scenarios and export ramp-up under pre-defined climate policy targets and sectoral developments. The pathways provide insights regarding the impact of climate policy targets, annual expansion limits, grid expansion restrictions, domestic PtX demand and PtX export volumes, on capacity expansions and the development of final energy demands.

The workflow interface for modelling the energy transition in South Africa allows for certain parameters such as emission limit, investment costs, renewable or electrolyser capacity limits, etc. to be configured flexibly and evaluated via sensitivity or scenario analyses. Most of the data for modelling South Africa's energy system has been prepared in the form of a data bundle. Given that Meridian Economics is currently maintaining the PyPSA-RSA code, it is planned to publish and maintain the sector coupled model on their repository at **https://github.com/MeridianEconomics**. The model version used for this work is published at: **https://github.com/ljansen-iee/pypsa-rsa-sec**. Required datasets can be made available on request and are described in the installation instructions. As such, the model can be transferred to other local institutions.

Aspects outside the model's scope

- The potential for cooperation with neighbouring countries in the SADC region through imports or exports is not considered.
- Special technical (unit commitment) boundary conditions for the operation of plants, such as minimum up time, minimum part load, ramp up rates, are available as an option in PyPSA-RSA, but were neglected for the expansion planning of this study, as the calculations here are not based on units but on aggregated technology classes.
- The expansion of transmission lines is continuously optimised with an N-1 approximation, but PyPSA-RSA-Sec does not consider vertical infrastructure such as substations, transformers and switchgear, nor does it model system services such as reactive power support and inertia reserve.
- The PtX products generally available for export with the current codebase are gaseous or liquified hydrogen, ammonia, Fischer-Tropsch fuels. Out of the model's scope is the targeted production for export of other PtX products such as for example green DRI.
- Site-specific assessments of PtX production processes: The model used here aggregates and simplifies aspects that would be analysed in detail for a site-specific assessment for PtX. For instance, the model uses average feed-in time series per model region, which may differ from the actual site-specific time profiles of wind or solar plants.
- The output of Fischer-Tropsch synthesis is always several different liquid fuels (naphtha, diesel, kerosene). For instance, it's not possible to produce only e-kerosene with FT. The model neglects this technical constraint, known as the selectivity of the synthesis pathway assuming that other PtL products than e-kerosene are also used in South Africa.
- Socio-economic impacts such as job effects are not directly addressed or constraint by the energy system model.

2.3 Technologies and Parameters

2.3.0 Available Technologies Overview

The cross-sector analysis embodies a wide range of technologies. Below we delineate the generation, conversion, storage and transport technologies to be considered within the defined system boundaries of the model.

Electricity, heat generation and storage solutions

- Solar-utility scale PV, onshore wind, reservoir, and run-of-river hydropower,
- Thermal power plants including Open Cycle Gas Turbine (OCGT) and Combined Cycle Gas Turbine (CCGT),
- Hydrogen fuel cells,
- Nuclear power plants[8],
- Combined Heat and Power (CHP) systems, Heat Pumps (HP), gas boilers and electric boilers,
- Usage of biomass and biogas for high temperature heating
- Storage units, such as Li-ion batteries, Pumped Storage Hydropower (PHS), H_2 storage steel tanks,
- Salt cavern storage excluded (non-existent in South Africa).

Conversion technologies relevant for Power-to-X

- Proton Electrolyte Membrane (PEM) Electrolyser,
- PtX synthesis technologies such as methane (CH4), ammonia (NH3) and FT synthesis,
- Carbon Capture and Usage for unavoidable process emissions of cement production, and biomass/biogas capturing,
- Complementary technologies, such as Direct Air Capture (DAC), Air Separation Units (ASU) and seawater desalination.

Transmission and transport of energy and non-energy demands

- Simplified electricity transmission grid,
- Simplified new hydrogen pipeline network,
- No transport costs and transport infrastructure considered for methane, carbon-dioxide, freshwater, biomass, ammonia, or other products.

2.3.1 Parameters for PtX Technologies

Further assumptions regarding the investment and the input/output parameters of the PtX technologies under consideration are described below. The capital expenditure, fixed operation and maintenance costs, lifetime, and process efficiencies are defined for the years 2030 and 2050. The values for 2040 are interpolated. The cost assumptions for the power generation technologies are explained in detail in section 2.5.

8 For the study the addition of new nuclear power plants is deactivated before 2040 in the model due to long planning and construction periods of nuclear power. Note, that it was not possible to analyse the complexity (regulatory, construction time, and other practicability) of a nuclear power plant park expansion in detail within the scope of this study.

H_2 electrolysis is the most important component of any PtX process. The future cost of this technology is highly uncertain. All types of electrolysers (Alkaline, PEM, AEM, SOEC) are still under development, and both literature and manufacturers' reports show a wide range of anticipated future investment costs. The estimated costs of PEM electrolysers reported in literature for 2050 vary from <236 USD2023/kW [50] 1,107 USD2023/kW [51]. For 2022, the IEA Global Hydrogen Review of 2023 [37] reports a CAPEX range of 1700 – 2000 USD2022/kW. However, the same study estimates that, based on the announced projects and economics of scale, the costs could go down to 720-810 USD/kW by 2030. Furthermore, one manufacturer in 2024 offers an electrolyser system for 1000 EUR2024/kW [52] indicating a significant cost reduction compared to the cost levels of 2022, which were caused by material shortages.

The GHCS aims to capitalise on South Africa's unique advantage in the global supply of PGMs. This speaks to a preference for PEM technology in the future GH economy to localize PEM electrolysis technology equipment and components. Additionally, costs for this technology are projected to decrease by 2030, making it the most suitable technology for accommodating variable renewable energy sources. Consequently, this study considers large-scale PEM electrolysis systems (>100MW to Gigawatts). The CAPEX is estimated at 1,004. USD2023/kW, decreasing to 632 USD2023/kW in 2050. The efficiency increases from 63.6% in 2030 to 71% in 2050.

Furthermore, electrolysis requires fresh or pure water as input for the process and cooling. The stoichiometric ratio is 9 litres per kg of hydrogen. Manufacturer specifications range from 10.01 to 22.4 litres/kgH_2. This study assumes 20 litres/kgH_2 which corresponds to 0.6 m3/MWhH_2.

Table 2: H_2 electrolysis parameters (PEM). Based on [37, 53, 54].

Parameter	Unit	2030	2050
CAPEX	USD2023/MWH_2	1,003,509	632,238
FOM	%/year	5.0%	5.0%
Lifetime	Years	20	20
Efficiency	MWhH_2/MWhel	63.6%	71%
Freshwater input	m3/MWhH_2	0.6	0.6
Heat output	MWhH_2/MWhel	0.204	0.13

South Africa already operates around 10 desalination plants, stretching from Lambert's Bay in the west to Richards Bay in the east, to combat water scarcity. As fresh water will become increasingly scarce in the future, seawater desalination plants are used in the model to produce as much freshwater as the H_2 electrolysis consumes. In this study, the CAPEX costs for seawater desalination plants decrease from 45,030 to 28,793 USD2023/m3/h (or 5.63 to 3.6 USD2023/m3/a) and the electricity consumption for the water pumps is 4.0 kWhel/m3 of water. Because water pumps are generally a mature technology, it is assumed that electricity consumption will remain constant. The operating costs are assumed to be 4% of the annual CAPEX, with a lifetime of 30 years.

Table 3: Seawater desalination parameters. Based on [55].

Parameter	Unit	2030	2050
CAPEX	USD2023/m3/h	45,030	28,793
FOM	%/year	4.0%	4.0%
Lifetime	Years	30	30
Electricity input	kWhel/m3	4.0	4.0

The Haber-Bosch technology for ammonia synthesis is considered a mature technology. Therefore, the CAPEX for ammonia production is listed as USD 774,870 per MW of ammonia capacity for both 2030 and 2050 – assuming plant sizes larger than 40t/h. These investment costs equate to 3,9 million USD/t/h. The efficiency of the process is 83%. Besides hydrogen as an input, the process also needs 0.158 tN2/MWhNH3 or 0.81tN2/tNH3 nitrogen and consumes 64 MWh electricity per tNH3 (0.125 MWhel/MWhNH3). The specified electricity consumption includes the Air Separation Unit (ASU).

Table 4: Ammonia synthesis (Haber-Bosch). Based on [56].

Parameter	Unit	2030	2050
CAPEX	USD2023/MWNH3	774,870	774,870
FOM	%/year	2.0%	2.0%
Lifetime	Years	20	20
Efficiency	MWhNH3/MWhH_2	83%	83%
Electricity input	MWhel/MWhNH3	0.125	0.125
Nitrogen input	tN2/MWhNH3	0.158	0.158
Heat output	MWhth/MWhH_2	0.064	0.064

The CAPEX costs for the nitrogen feedstock production via air separation unit are 1.91 million USD2023/tN2.

Table 5: Air Separation Unit. Based on [56].

Parameter	Unit	2030	2050
CAPEX	Million USD2023/tN2	1.91	1.91
FOM	%/year	2.0%	2.0%
Lifetime	Years	20	20
Electricity input	Included in ammonia synthesis process		

In 2030, the capital expenditures (CAPEX) for hydrogen storage tanks including costs for compressors are estimated to be USD 61,500 per MWh of storage capacity. By 2050, this cost is expected to decrease significantly to USD 28,758 per MWh. This corresponds to 2049 USD/kgH_2 or 959 USD per kgH_2 in 2050.

Table 6: Hydrogen storage tank incl. compressor. Based on [57].

Parameter	Unit	2030	2050
CAPEX	USD2023/MWhH_2	61,500	28,758
FOM	%/year	1.0%	2.0%
Lifetime	Years	30	30

For the Power-to-liquid (PtL) synthesis, the Fischer-Tropsch process is considered. The next tables describe the costs and efficiency parameters of the PtL synthesis. With Sasol's proprietary Fischer-Tropsch (FT) technology, South Africa is a leader in this field. Sasol's FT technology can also be used with green hydrogen and sustainable CO_2 to produce jet fuel, for example. The Sasol Climate Change Report 2023 estimates that reusing existing plants saves 30% of the cost of building a new greenfield plant [58]. The authors of the study do not have further details on Sasol's Fischer-Tropsch costs. Therefore, we use the assumptions from the literature, which assume that scaling effects reduce costs from 2030 to 2050. We reduce the CAPEX estimates in the literature by 30% for 2030 and by 10% for 2050 to take into account technological knowledge and existing assets in South Africa. Thus, we thus assume that South Africa has an advantage regarding Fischer-Tropsch technology and is advanced on the learning curve compared to other countries. However, future studies are recommended to explore this in greater detail.

Table 7: Fischer-Tropsch synthesis (PtL). Based on [51, 59, 60].

Parameter	Unit	2030	2050
CAPEX	million USD2023/MWFT	0.80	0.52
FOM	%/year	5.0%	5.0%
Lifetime	Years	20	20
Efficiency	MWhFT/MWhH_2	0.72	0.76
CO_2 input	tCO_2/ MWhFT	0.326	0.276
Electricity input	MWhel/MWhFT	0.007	0.007
Heat output	MWhth/MWhH_2	0.077	0.077

Methanol synthesis based on the Sabatier process is a well-established method for synthesizing methane (CH_4) by reacting hydrogen (H_2) with carbon dioxide (CO_2) over a catalyst. The investment cost (CAPEX) per MWH_2 capacity, measured in million USD2023/MWH_2 is projected to be 0.57 million USD2023/MWH_2 by 2030, decreasing to 0.44 million USD2023/MWH_2 by 2050.

Table 8: Methanol synthesis. Based on [51, 60, 61].

Parameter	Unit	2030	2050
CAPEX	million USD2023/MWH_2	0.57	0.44
FOM	%/year	5.0%	5.0%
Lifetime	Years	20	20
Efficiency	MWhCH4/MWhH_2	0.747	0. 789
CO_2 input	tCO_2/ MWhCH4	0.198	0.198
Heat output	MWhth/MWhH_2	0.085	0.085

Methanol synthesis involves converting hydrogen (H_2) and carbon dioxide (CO_2) into methanol (CH_3OH). This reaction offers a valuable pathway for producing methanol, a versatile chemical used as fuel, in plastics, and as a base material for various other chemicals. By 2030, CAPEX is projected at 0.66 million USD2023/MWH_2, with a decrease to 0.44 million USD2023/MWH_2 by 2050. Efficiency, expressed as MWhMeOH/MWH_2, indicates the effectiveness of the hydrogen-to-methanol conversion. The efficiency is expected to improve from 0.749 in 2030 to 0.791 in 2050, reflecting better energy conversion and process optimization over time.

Table 9: Methanol synthesis. Based on [60, 62, 63].

Parameter	Unit	2030	2050
CAPEX	million USD2023/MWH$_2$	0.66	0.44
FOM	%/year	5.0%	5.0%
Lifetime	Years	20	20
Efficiency	MWhMeOH/MWhH$_2$	0.749	0.791
CO_2 input	tCO_2/ MWhMeOH	0.248	0.248
Electricity input	MWhel/MWhMeOH	0.271	0.271
Heat output	MWhth/MWhMeOH	0.085	0.1

The capturing methods for producing CO_2-feedstock implemented as options in the model are carbon capture from methane combustion or biomass burned for industrial process heat, carbon capture of process emissions or direct air capture. The next tables describe the costs and efficiency parameters of direct air capturing.

Table 10: Direct Air Capture (DAC). Based on [64].

Parameter	Unit	2030	2050
CAPEX	million USD2023/tCO_2/h	9.35	5.81
FOM	%/year	4.0%	4.0%
Lifetime	Years	30	30
Electricity input	MWhel/tCO_2	0.315	0.255
Heat input	MWhth/tCO_2	1.62	1.312
Heat output	MWhth/tCO_2	0.2	0.2

Availability of CO_2 feedstock

Another important issue for PtX production is the availability of CO_2 as a feedstock. It is unlikely that DAC technology will be commercially available until 2040. This study draws on the NBI report titled "Decarbonising South Africa's petrochemicals and chemicals sector", and the most recent study on Carbon Sources for the Production of PtX Products and Synthetic Fuels in South Africa, to establish the basis for available quantities and associated prices of CO_2 from alternative sources.

Table 11: Potentials for captured CO_2 from Mineral, Petrochemical, Iron & Steel, and Power sectors, considering different pathways and assuming that carbon capture is applied to unavoidable emissions. Source: [65].

Sector	Process emissions share (unavoidable emissions)	2030 $MtCO_2$	2040 $MtCO_2$	2050 $MtCO_2$
Mineral (cement / lime)	65%	6.0-6.9	3.8-9.6	3.3-13.7
Petrochemical (CTL/petr. refining)	50%	29.9-38.7	11.4-36.0	7.1-34.6
Iron and steel	12%	1.1-1.3	0.9-1.4	0.5-1.6
Power	0%	170.9	126.2	155.4

2.4 Temporal and Spatial Resolution

When modelling an energy system with a high share of renewable energies, spatio-temporal aspects and cross-sectoral interactions need to be adequately considered. PyPSA-RSA is designed to conduct power capacity expansion planning studies at differing spatial and temporal resolutions, including 1, 11, 27 nodes with full time chronology (8760 h per year) for either a single year or multiple years with perfect foresight. This allows for variability in renewable energy generation to be accounted for in the optimisation process.

Within this project's scope, planning the capacity expansion over several horizons was computationally intensive, which is why the spatial resolution of 11 nodes was selected. This model resolution divides South Africa into 11 supply regions, corresponding to the Generation Connection Capacity Assessment 2023, namely Pelly, Western Cape, Limpopo, North West, KwaZulu Natal, Northern Cape, Gauteng, Mpumalanga, Hydra Cluster, Free State, Eastern Cape [30]. Since most publicly available demand datasets are not broken down sub-nationally, additional assumptions and data sets for the distribution of electricity and fuel demand (e.g. gridded gross value-added data) were used. This is discussed in more detail in Section 2.8.5. The model is solved in ten-year steps from 2030 to 2050 with 8760 hours per year. The computation time for this model resolution is between 7.5 and 12 hours per scenario and per planning year. The multi-zonal and geospatially explicit model will serve to complement existing South African PLEXOS and SATIMGE models.

2.5 Data for PtX Export Assumptions

2.5.0 Potential Export Volumes

As part of the scenario definition in this study, we define predetermined export targets (target-setting). This allows us to analyse the feasibility and infrastructure requirements of strategic targets. As a basis for defining the export target (see 3.3), the planned important projects up to 2030 and the hydrogen volumes of the existing hydrogen strategies or scenarios for South Africa are described below.

The short- to mid-term future potential export volume is influenced, among other factors, by the successful implementation of domestic projects and by the global ramp-up of PtX demands. To estimate the volume of planned projects, the major hydrogen, ammonia, and synthetic fuel projects with announced sizes and commissioning dates before 2030 were collected and are listed in Table 12. The main sources for this list are the Strategic Integrated Projects of „Infrastructure South Africa" [66, 67] and the IEA's global PtX project database [68]. Some of the project sizes are stated with installed capacity, and some with planned annual production capacities. Converted, the estimated project total electrolyser capacity up to 2030 is 4.3 GW of or 750 ktH_2/year. Export ports which have been published in concept and feasibility studies include the newly planned Boegoebaai Port, Coega port, Richard Bay (HySHiFT) and Saldanha bay.

Table 12: PtX production projects with announced sizes and planned commissioning date before 2030. Based on [66–68].

Name	Project Status	Infrastructure South Africa	Date	Product	Announced Size
Anglo-American Mogalakwena mine	Operational	-	2022	H_2	3.5MW
Boegoebaai Green Hydrogen Development Programme - Phase I	Feasibility study	registered	2028	H_2	1200MW
HIVE Ammonia Project	Feasibility study	registered	2028	Ammonia	900kt NH3/y
Sasolburg Green Hydrogen Programme	Feasibility study	registered	2024	H_2	60MW
Secunda SAF HySHiFT Project – Phase I	Feasibility study	registered	<2030	FT fuels	40MW
Secunda SAF HySHiFT Project – Phase II	Feasibility study	registered	?	FT fuels	200MW
Prieska Power Reserve Project – Phase I	Feasibility study	registered	2025	Ammonia	72 kt NH3/y
Prieska Power Reserve Project – Phase II	Concept	registered	2030	Ammonia	500 kt NH3/y
Enertrag Indigen Project (e-methanol)	Concept	awaiting	2027	MeOH	120MW

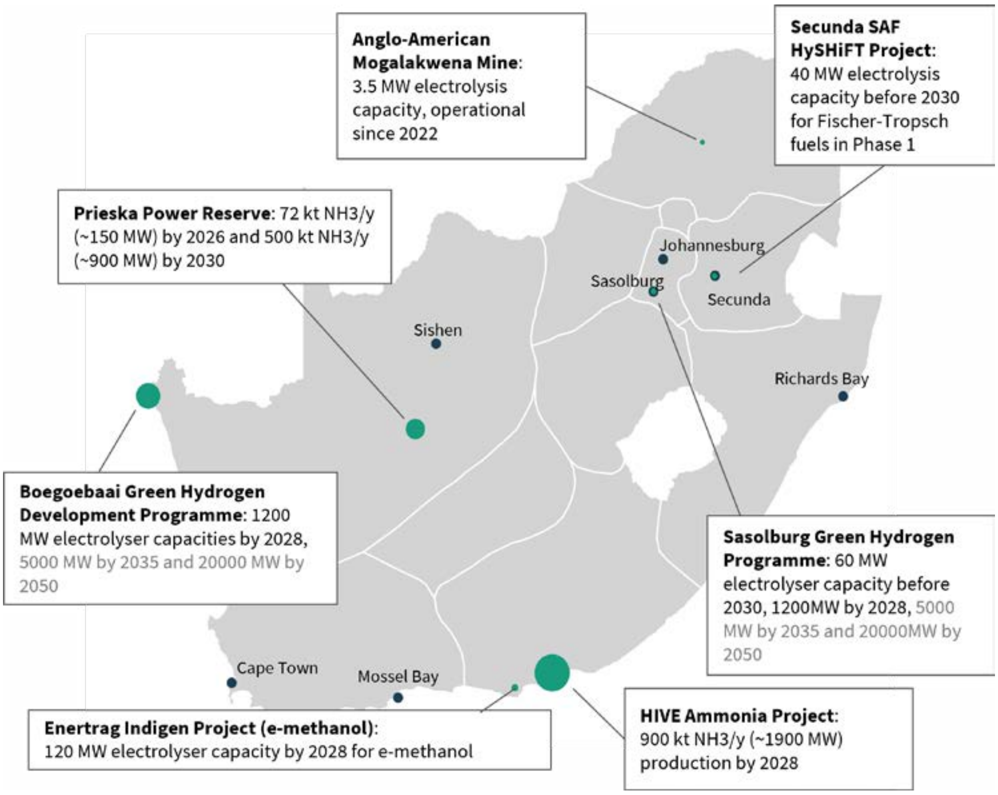


Figure 13: Announced projects for PtX by 2030 (green H_2, ammonia and FT-SAF). Based on [66–68].

The announced PtX projects by 2030 (for green H_2 and ammonia) based on IEA PtX Project database [68] and Infrastructure Projects Gazette [66] are geographically illustrated in Figure 13. The Boegoebaai Green Hydrogen Programme and Prieska Power Reserve are indicative of the region's (Northern Cape) abundant renewable resources, positioning it as a future global leader in green hydrogen. In the Eastern Cape the HIVE Ammonia Project highlight the strategic location for export-oriented production, utilizing ports and existing infrastructure to access global markets. The Enertrag Indigen and Sasols projects at both Sasolburg and Secunda demonstrate South Africa's commitment to diversifying its hydrogen economy, integrating both e-methanol and green Fischer-Tropsch fuel production.

The abovementioned list of PtX production projects does not include larger projects that will not come online until after 2030, or for which we have no information on dates or capacities. Projects in this category include Secunda SAF HySHiFT Project - Phase II with 200MW and the Boegoebai plan with up to 20 GW by 2050, or the Hydrogen Valley Programme, which provides no information on dates or generation capacities. However, the Hydrogen Valley study quantifies green H_2 consumption in three regions. In the accelerated scenario of this study, demand for 2030 is expected to be 74 kt in Johannesburg/Pretoria, 70 kt in Durban/Richards Bay and 41 kt in Mogalakwena and Limpopo.

According to the JET-IP, local demand for green hydrogen is expected to still be limited by 2030, with approximately 0.2 mtpa driven by sustainable aviation fuels, vehicle mobility, and green steel. Domestic potential is estimated at 2–3 Mtpa by 2040, reaching up to 6–10 Mtpa of demand for local production by 2050. The investment plan also stated that if supply can scale in line with forecasts, export demand could reach 0.5 to 0.7 mtpa by 2030, up to 2 mtpa by 2040 [3].

South Africa's green hydrogen export potentials (Mt H_2) were also assessed in various scenario definitions by the IHS Markit analysis, Industry research report, Engie global IEA Net Zero study, and Sasol [10] as illustrated in Figure 14. However, the latest most notable scenario assessment was conducted as part of the GHCS, overseen by the Department of Trade, Industry and Competition (DTIC) and developed through multiple work clusters. The strategy agreed upon is depicted in Figure 15, which foresees a green hydrogen production and demand uplift scenario to scale up South Africa's green hydrogen production to 3.8 Mtpa by 2040 and 7 Mtpa by 2050. [10]

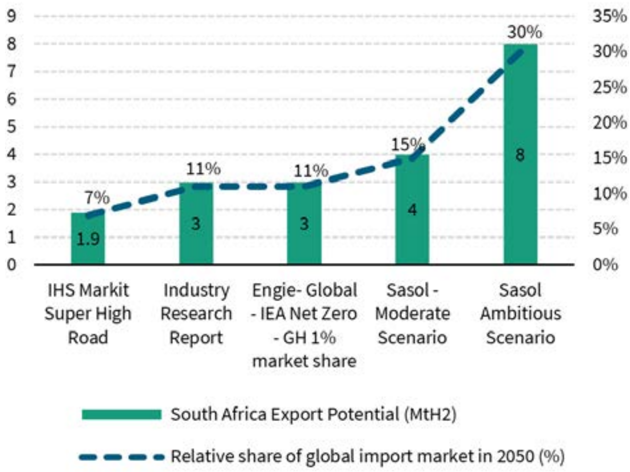


Figure 14: Export potential derived from market shares in scenarios of IHS Markit analysis, Industry research report, Engie global IEA Net Zero, and Sasol for South Africa. Own illustration based on [32].

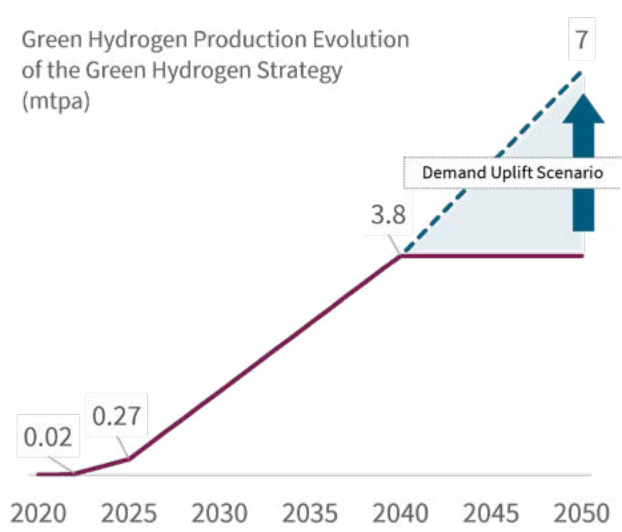


Figure 15: Illustration of the green hydrogen production and demand uplift scenario of the Green Hydrogen Commercialisation Strategy to scale up the GH production of South Africa to 3.8 Mtpa by 2040 and 7 Mtpa by 2050. Source: [10].

With numerous projects spanning green hydrogen, ammonia, and e-fuels, and an official strategy of 2022 the country is embracing a multi-faceted approach that capitalizes on its natural resources and aligns with global sustainability trends. By meeting these targets, South Africa is poised to bolster its energy independence, reduce carbon emissions, and play a pivotal role in the global hydrogen supply chain by 2030 and beyond. The sectoral and infrastructural dependencies of pathways with a high or low hydrogen share are analysed in the model-based scenario analysis of this study. The assumed export volumes of the scenario can be found in chapter 3.3 and are aligned with the GHCS. The results analysis also assesses the current spatial location of the planned projects.

2.5.1 Export Price Estimates

Literature and current strategies expect that the main net importers of hydrogen and hydrogen-derivatives (PtX fuels) will be the European Union, Japan and South Korea. Due to the distances between South Africa and these importers, South Africa will likely export higher value PtX fuels and products directly or indirectly (via book and claim for international shipping and aviation). In this study, we consider ammonia and Fischer-Tropsch fuels as export options.

When estimating PtX prices, it is assumed that prices will be higher than the production costs at the very best locations globally. Demands in Europe, USA and Japan will exceed the production capacities at the world's leading facilities. As such, current trade relations and trade plans indicate that importers are keen to diversify their energy imports. For this study, prices were estimated based on a simplified global market modelling approach (with market and trade ramp-up constraints) and on literature. Projected green H_2 production costs for suitable sites are illustrated in Figure 16 based on the global PtX site assessment conducted by Fraunhofer IEE [49]. The assessment tool calculates production costs for different PtX fuels at multiple representative sites around the globe. Following the full-cost approach, the production costs form a supply curve while demand quantities are taken from the literature. The market prices are determined by the intersection of supply and demand, subject to the constraints of regional capacity expansion and fuel transportation costs.

However, these derived price estimations need to be interpreted with caution. In the coming years, PtX prices will mainly be determined via direct contracts and subsidised auctions. It's uncertain how future PtX product prices will develop due to the conditions of these auctions and contracts. Prices could be dominated by the future market power (oligopoly) of individual players. On the other hand, production costs will heavily depend on investment costs for electrolysers, solar PV and wind power plants. Electrolysis costs in particular have recently been higher than expected, and it is uncertain when they will decrease. For instance, if H_2 electrolysis costs remain elevated in 2030, the market prices for H_2 derivatives worldwide would also remain high. Conversely, if costs decline due to technological advances or economies of scale, prices would be lower[9]. The price assumptions that were used for the exports of NH3 and Fischer-Tropsch fuels in this study are summarised in Table 13.

The estimated price for H_2 (gaseous) is included as a reference, although it cannot be exported directly with the selected model configuration.

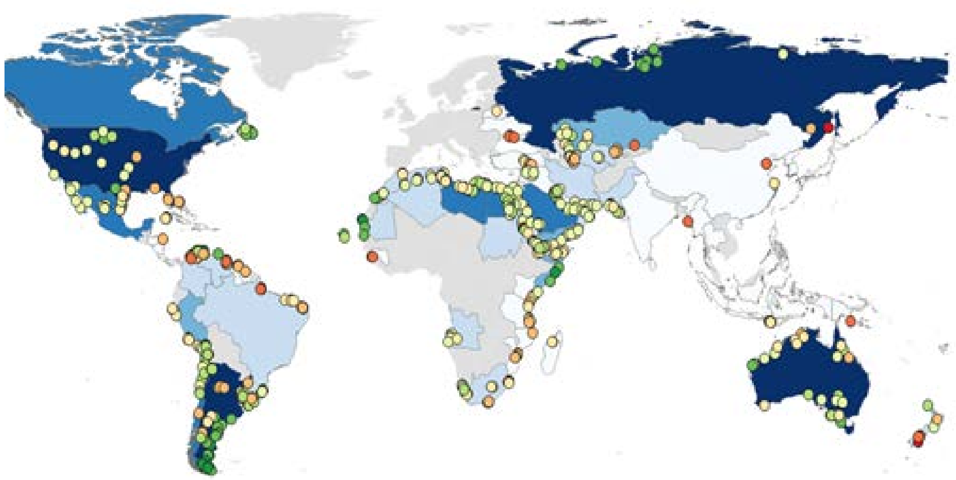


Figure 16: Global GIS based assessment of suitable H_2 production sites and corresponding costs (green: low costs; red: high costs) in 2050. Production costs range from 60 USD2023/MWhLHV (dark green) to 137 USD2023/MWhLHV (red). Area potential ranges from <5000 km2 (light blue) to >100.000 km2 (dark blue). Sources: Based on [49, 70].

Table 13: Pre-trade (without shipping costs) price estimates for H_2, NH3 and FT in South Africa. Own assumptions based on [70].

PtX product price	Unit	2030	2050
Green H_2	USD2023/MWh	113	78
	USD2023/t	3,752	2,612
Green NH3 liquid	USD2023/MWh	142	112
	USD2023/t	735	579
Green Fischer-Tropsch fuels	USD2023/MWh	207	158
	USD2023/t	2,559	1,953

9 Recently, reports indicate that the cost of Chinese electrolysers has fallen sharply [69].

2.6 Capital Costs for Wind and Solar

The energy system model's objective function encompasses the total capital, operational, and fuel expenses associated with capacity expansion within the projected timeframe spanning from 2024 to 2050, with future costs discounted at a rate of 8.2% [20]. Given that the emerging expansion plan is a least-cost optimisation, it is crucial for cost and efficiency assumptions to be transparent and agreed-upon amongst relevant stakeholders.

Regarding new-build power plant technology cost assumptions in the South African context, several cost assumptions which were used as inputs in the draft IRP 2023 raised concerns amongst stakeholders in the energy sector. One such concern was the exclusion of future technology learning in the long-term capacity expansion plan. It is essential to account for technology cost dynamics in energy planning processes, particularly when considering the cost of new renewable energy generation technologies in contrast to more mature conventional generators.

A comparative analysis of technology and cost assumptions including the IRP 2023 data was published in early 2024 [35, 71] including data from various power system studies and several technology cost assumption sources [28, 71–77]. We incorporated Fraunhofer IEE's cost assumptions in the published comparisons. Comparative capital costs for wind and solar PV are presented in Figure 17 and Figure 18 respectively. Given the varying roles of technologies in the power system, comparisons using LCOE are typically considered within each technology category. While incorporating both CAPEX and O&M assumptions into LCOE is valuable, the resource potential for renewable energy generators varies geographically in a multi-nodal model. As a result, there will be a range of LCOE values for renewable energy generators based on the varying capacity factors at each node. Therefore, we present a comparison of capital costs.

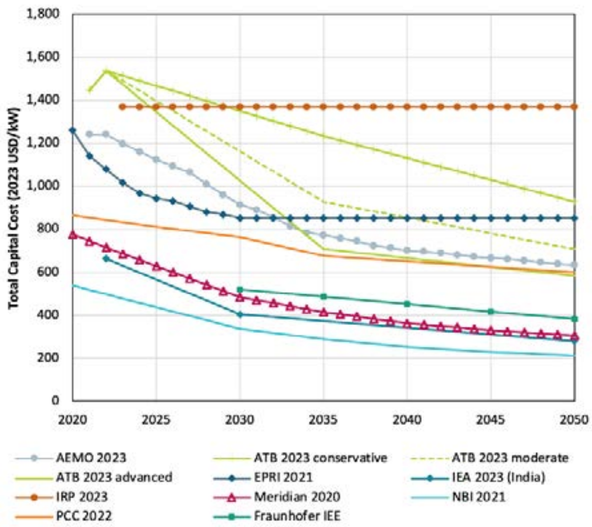


Figure 17: Solar PV cost comparison. Own illustration based on [35].

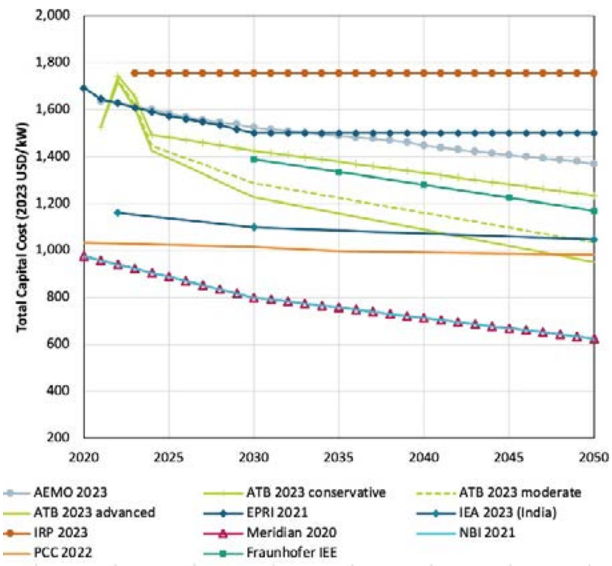


Figure 18: Wind capital cost comparison. Own illustration based on [35].

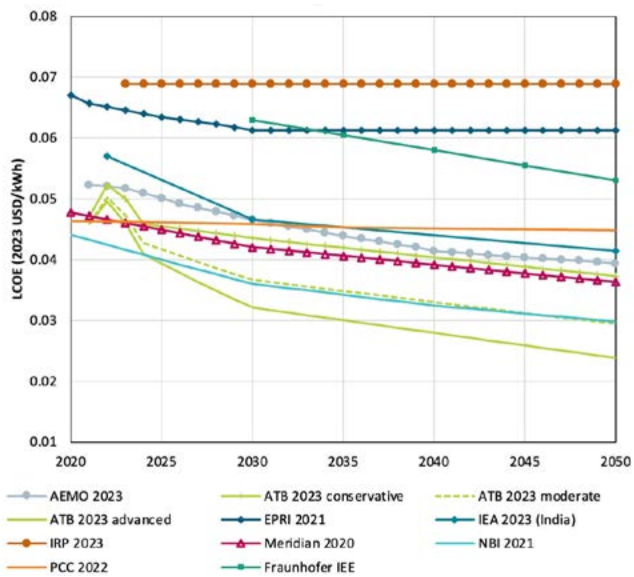


Figure 19: Comparison of wind LCOE values. Own illustration based on [35].

In most cases the Fraunhofer IEE cost assumptions fall within a reasonable range of the reported studies, with the exceptions of nuclear and coal technologies. The nuclear costs used in the IRP 2023 draft were obtained from vendors through a Request for Information (RFI), representing values which are non-binding and low compared to other data sources [35].

For this study, locally informed renewable energy cost assumptions published by Meridian Economics were utilised. Meridian Economics has released several publications aimed at establishing a platform where local analysts and researchers can share input data and assumptions, modelling approaches, tools and study results. This project intended to support these initiatives and align with local modelling inputs. Although the wind capital costs from Meridian fall within the lower range, the wind LCOE used by Meridian Economics falls within a higher mid-range of the reported sources with an assumed capacity factor of 36.1%, interest rate of 0.3% and fixed O&M based on the IRP 2019 [35]. Constant capital costs were assumed for conventional technologies up to 2050.

2.7 Fossil Fuel Prices

The model in this study does not differentiate between different types of end consumers (large industrial off-taker, household customer) in terms of oil and gas prices. Hence, the cost optimisation of this study neglects various taxes or levies besides a CO_2 price. For the modelling exercise at hand, fuel prices are own assumptions based on average values of the World Energy Outlook Scenarios: Stated Policies and Announced Pledges. The resulting price trends are declining slightly. The numbers shown in the table do not consider CO_2-pricing. A CO_2 price on fossil fuels will in turn make them more expensive based on the specific CO_2-emissions per fuel type.

Table 14: Oil and gas prices for 2030 and 2050 without a CO_2-price component. Own assumptions for South Africa based on [76].

Fossil fuel	Unit	2030	2050
Crude oil	USD2023/MWh	55	49.5
(Border price)	USD2023/barrel	89.6	80.6
Natural gas	USD2023/MWh	33.7	33
(Plant gate price)	USD2023/MBtu	9.9	9.7

2.8 Representation of the Electricity System

Data collection for the electricity supply system was obtained from the JET-IP datasets compiled by ESRG for the reference year data (2021), as well as for the definition of realistic electricity capacity expansion scenarios.

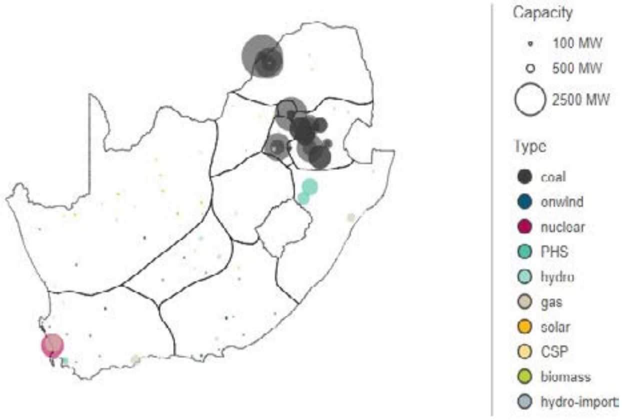


Figure 20: Map for existing Eskom and non-Eskom power plants. Own illustration based on [1, 40].

2.8.0 Existing Power Stations

PyPSA-RSA uses a geo-specific power plant list including power stations in operation of Eskom together with power plants (PV and Wind) built and operated by other parties (including those promoted by the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP)). Data pertaining to existing conventional and renewable power stations was obtained and validated from various sources including data from Eskom Holdings [34], the Department of Mineral Resources and Energy [78], OpenStreetMap [79], CSIR [42] and Meridian Economics [40].

2.8.1 Annual energy availability factor (EAF)

The model also considers the plant-specific Energy Availability Factors (EAF) of the Eskom plants. The EAF is given as the difference between the maximum availability and all unavailability (planned and unplanned), expressed as a percentage. The average annual EAF of all coal plants from 2020 to 2021 was 0.57, while the average EAF for nuclear plants was 0.73 and for OCGT plants was 0.96. The Draft IRP 2023 considers the total Eskom fleet EAF, which is inflated due to the higher EAF contributions from other technologies (including peaking plants with availabilities over 95%, and nuclear with a higher EAF following completion of the life extension). The annual average coal EAF was calculated by Meridian Economics by estimating and removing the contribution from the nuclear and peaking stations [28]. A slow recovery in the coal fleet EAF of 58% by 2030 (similar to the 2020-2021 performance), 62% by 2040, and 72% by 2050 is assumed.

2.8.2 Area and Renewable Potential

Potentials and restrictions for Wind, PV and PtX were calculated using exclusion and weighting criteria. They include, but are not limited to, protected areas, land-use data, distance to settlement areas, geospatial water-risk indicators, distance to water sources, pipeline and port locations, and meteorological data. The parameters together with respective buffers for wind and PV and datasets used are summarised in Table 15. The approach also considers the availability of infrastructure as indicated in Table 16. Infrastructure requirements can be fulfilled either via Condition A or Condition B.

Based on feedback received from the stakeholder engagements, the following criteria were considered among others when assessing suitable areas and Full Load Hours (FLH) for wind and solar PV:

- Exclusion of built-up areas, protected areas, slopes and low FLH.
- A distance to the electricity grid of less than 60 km.
- Distance to cities with more than 20,000 inhabitants of less than 100 km.

FLH is a metric used to measure the equivalent number of hours a power plant operates at its maximum capacity over a year. It's a useful way to express the actual output of a power plant relative to its potential maximum output (ratio of annual energy output over installed capacity).

Table 15: General assumptions and datasets for buffer zones pertaining to wind and solar PV installations.

Parameter	Buffer Wind [m]	Buffer PV [m]	Dataset
All protected natures (marine, wetlands, onshore..)	100	100	OSM-Data, World Database on Protected Areas
Critical Habitats	Not used	Not used	Global Critical Habitat Screening Layer
Coastline	1000	1000	Exclusive economic zones v11
Rivers, water bodies and wetlands	0	0	OSM-Data, Global Waterbodies Dataset (ESA), ESA/Copernicus LandCover
Wetlands	100	100	OSM-Data, ESA/Copernicus LandCover
Croplands of any kind	Not used	0	OSM-Data, ESA/Copernicus LandCover, Global Food Security-Support Analysis Data
Forests	0	0	OSM-Data, ESA/Copernicus LandCover
Telescopes	4000	200	OSM-Data
Buildings	1000	300	OSM-Data, ESA/Copernicus LandCover, World Settlement Footprint
Roads (primary, secondary)	200	100	OSM-Data
Railway	250	150	OSM-Data
Powerlines and substations	300	150	OSM-Data
Major airports	5000	1500	OSM-Data
Landing strips	1000	0	OSM-Data
Military Areas	2000	1000	OSM-Data
Telecommunication towers	6000	200	OSM-Data
Slope (>4°)	0	0	Shuttle Radar Topography Mission (SRTM) 30

Table 16: Conditions and datasets for the availability of infrastructure.

Infrastructure Parameter	Condition A	Condition B	Dataset
Water availability	Distance to coastline < 100km (desalination)	Distance to fresh surface water < 100km + absence of water scarcity	Exclusive economic zones v11, OSM-Data, Global Waterbodies Dataset (ESA), ESA/Copernicus LandCover, WIR Aqueduct Water Risk Atlas 4.0
Distance to cities (availability of qualified staff, infrastructure and local demand centres)	Distance to cities (>20k inh.) < 100km		world cities, simplemaps
Distance to major roads	Distance to primary/ secondary roads < 100km		OSM-Data
Distance to electric grid	Distance < 60km		OSM-Data
Wetlands	100	100	OSM-Data, ESA/Copernicus LandCover

Hourly generation profiles for onshore wind, and photovoltaic for one representative year were created with the tools windANTS and pvANTS using spatio-temporal weather data from ECMWF's ERA5 [39]. The time series data is generated for each ERA-model-pixel to ensure high spatial resolution and accuracy. Some of the considered parameters of windANTS are up-to-date wind turbine specifications, power curves, wind speeds, and shading effects. For the photovoltaic profiles, global horizontal irradiation, ambient temperatures, and orientation parameters are considered.

The weighted mean FLH per supply region ranges between 1584 h in KwaZulu Natal to 1898 h in the Northern Cape for solar PV. The daily capacity factor averaged from hourly data for the Northern Cape is illustrated in Figure 21. The weighted mean FLH per supply region ranges between 2268 h in KwaZulu Natal to 3561 in the Hydra Cluster model region for wind. The daily capacity factor averaged from hourly data for the Hydra Cluster is illustrated in Figure 22.

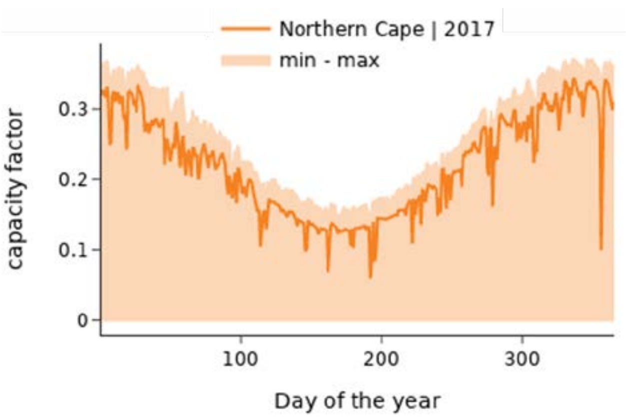


Figure 21: Daily solar PV capacity factor averaged from hourly data for the Northern Cape. Own illustration.

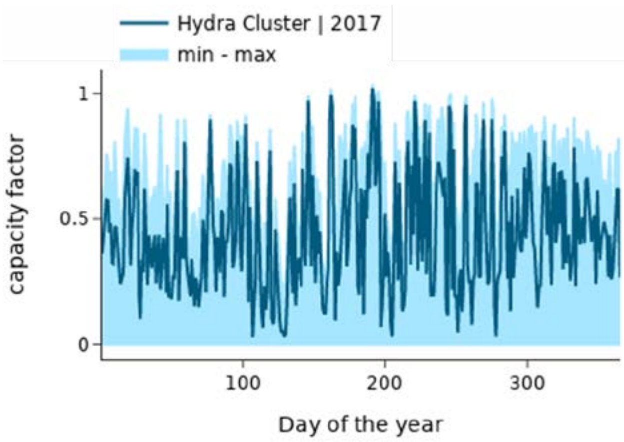


Figure 22: Daily wind capacity factor averaged from hourly data for the Hydra Cluster. Own illustration.

The total available capacities identified for solar PV and onshore wind based on the potential area analysis (considering buffer zones, infrastructure requirements and resource potential) and are illustrated in Figure 23 and Figure 24. The total emerging potential capacity are higher or equal to 121 GW per region for solar PV, and the total capacity identified for onshore wind exceeds 203 GW per region apart from Pelly.

The results of the potential area analysis exhibit promising potential for both solar PV and onshore wind. The Hydra Cluster appears to have exceptionally good weather conditions. However, during a workshop there were concerns about the availability of water, water pipes and adequate roads. The construction of a water pipeline across the mountains to the sea was viewed with scepticism. Therefore, the Hydra Cluster is excluded for sustainable H_2 electrolysis in this study.

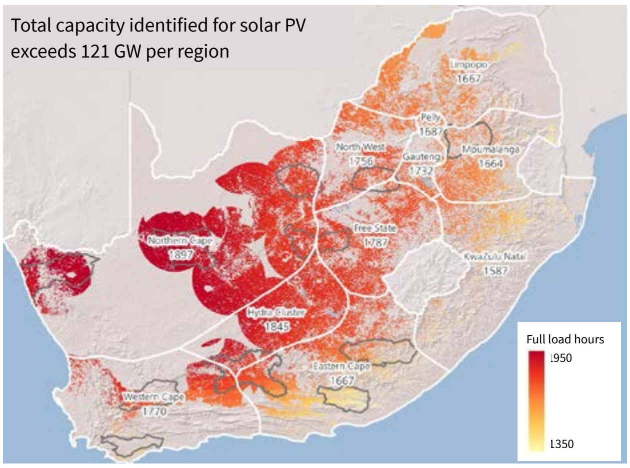


Figure 23: Representation of solar PV full load hours with consideration of exclusion criteria. Own illustration.

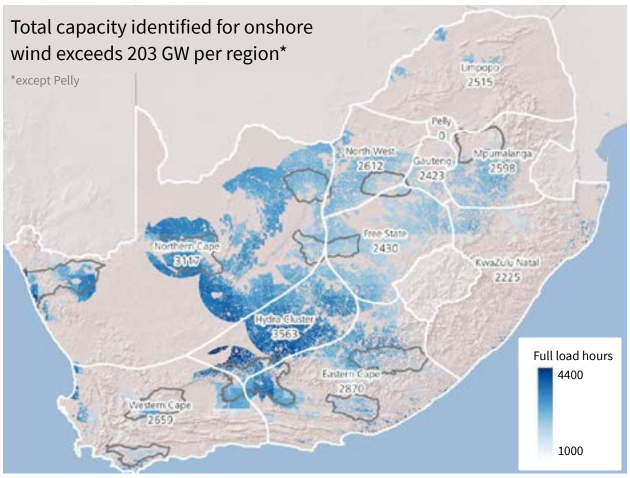


Figure 24: Representation of onshore wind full load hours with consideration of exclusion criteria. Own illustration.

2.8.3 Grid Constraints

When investigating the effect of grid constraints on wind and solar PV capacity expansion up to 2030, we considered the Generation Connection Capacity Assessment (GCCA) and the Transmission Development Plan (TDP) [10]. The GCCA 2024 provides details of the generation connection capacity of the planned transmission network with all the projects that are expected to be commissioned by 2025. Network redundancy is assumed for integration of distributed generation (DG), inverter-based resources (IBRs), or distributed energy resources (DERs) at an aggregated transmission level in the GCCA. To conduct an analysis of the generation connection capacity of the planned transmission network, a detailed study with network redundancy would need to be done and given that the GCCA provides the estimated generation connection capacity in the short-term (up to 2025), we investigated the TDP to get an indication of the planned transmission expansion and connection capacity over the time horizon up to 2030.

The TDP covers a period from 2023 to 2032 and seeks to meet the requirements of electricity consumers in South Africa by maintaining the legislated adequacy and reliability of the transmission grid. The planned projects and major assets are published in terms of transformers, overhead lines, capacitor banks and reactors. The TDP also publishes provincial cumulative generation up to 2032, which considers the following criteria:

- Exclusion of sensitive areas following outcomes of the strategic environmental assessment (corridors) regarding areas suitable for solar and wind,
- Maximum PV that can be installed within a 60 km radius of a substation,
- EIA applications from IPPs in the past few years,
- Applications for grid connection by IPPs in the past few years,
- CSIR survey of IPPs regarding which technologies may be installed at different locations in the next few years,
- GCCA 2024 results indicating where there is capacity on the grid,
- Projected dates of major strengthening projects,

A summary of the cumulative provincial allocation of generation by technology up to 2032 published in the TDP 2023 is illustrated in Figure 25.

---

10 Transmission capacity refers to the maximum amount of electricity that can be transported across the grid's transmission lines across regions, while generation connection capacity indicates the maximum amount of electricity that power plants can feed into the distribution grid. The generation connection capacity depends on the capabilities of the power plants, their connection agreements with the grid operator and the available substation capacities. While transmission capacity focuses on the grid's ability to carry power, generation connection capacity deals with how much power can be produced and injected into the grid.

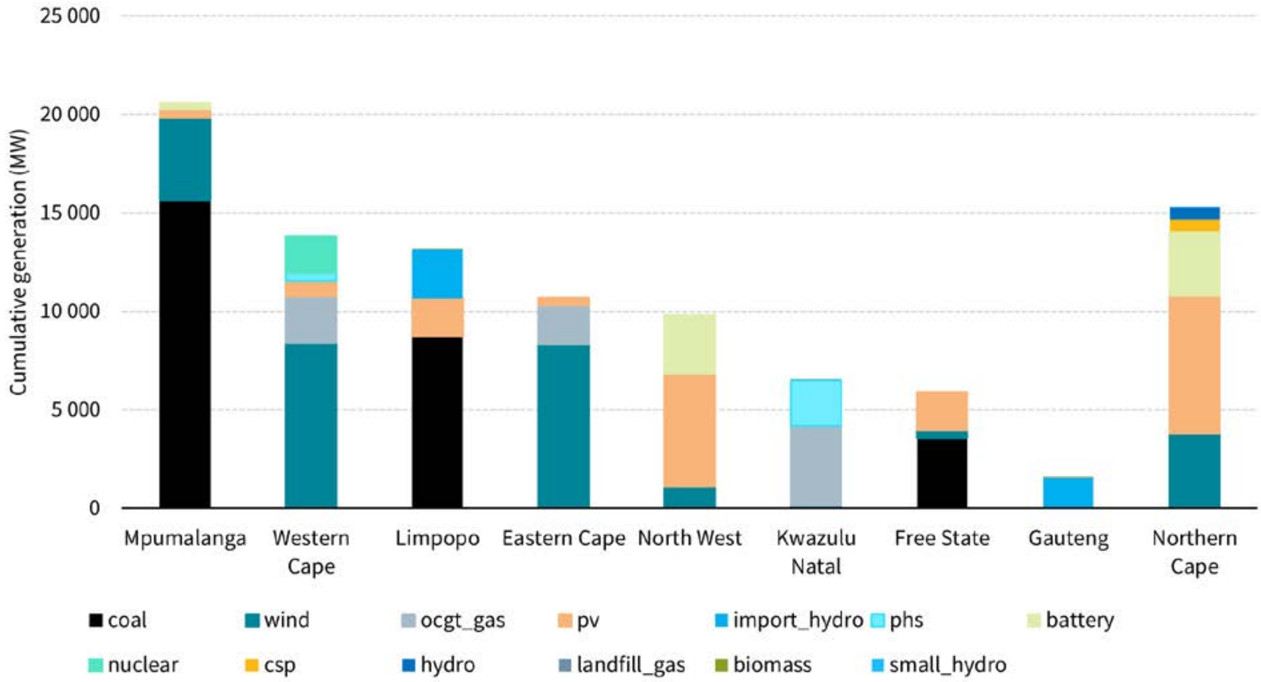


Figure 25: Cumulative provincial allocation of generation by technology up to 2032. Based on [2].

2.8.4 Modelling the Transmission Network

The South African IRP utilises a copper plate model, which neglects the constraints of the transmission network (single node PLEXOS model). This project leverages a spatially disaggregated model with multiple nodes and transmission connections in order to consider grid constraints.

When condensing the grid into a simplified network model, the regional resolution of the study is aligned with the grid connection capacity assessment (GCCA 2024) for South Africa. The four-level hierarchy published within the GCCA is used to aggregate and disaggregate the granularity of the grid considering the following levels:

- substation level (the transformation capacity at the substation)
- substation area level (which is limited by the loss of any single line connecting the substation to the rest of the grid)
- local area level (the transmission network connecting transmission substations in a local area, which is limited of under the loss of any single line in the local area)
- and supply area level (the transmission network connecting all local areas within a supply area, which is limited by the loss of any single line in the supply area)

The hierarchy is such that a substation lies within a substation area, several substation areas lie within a local area, and several local areas lie within a supply area. A condition of the hierarchy is that the combined substation area limits may not exceed the local area limit, and the combined local area limits may not exceed the supply area limit; that is, and the generation connection capacity would consequently be limited by the lowest capacity at all the levels [80].

Publicly available GIS shape files representing spatial data published by Eskom were used to demarcate the supply regions and existing transmission lines [29]. Digitised geo-referenced images from the TDP were used to obtain the approximate locations of the planned transmission lines by Meridian Economics [81].

The amount of power that a transmission line can safely carry depends on several constraints, which can be categorized into two main types: Thermal constraints and Surge Impedance Loading (SIL) [82]. The power transfer capacity of a transmission line is mainly restricted by three factors: stability, voltage, and thermal limits [83]. The St. Clair curve, on the other hand, integrates the three primary factors that limit transmission capacity (thermal limitations, voltage drop limitations, and steady-state stability limitations) into one straightforward relationship which enables the estimation of a transmission line's maximum capacity based solely on its length [84]. To calculate the line loading potential of the future grid (inter-regional transfer capacity), the St Clair curve is used in the PyPSA-RSA model to determine the maximum loadability.

We employ a spatially disaggregated version of PyPSA-RSA that allows for 11 nodes. The hourly resource profile is based on a spatially aggregated profile of each selected province assuming only suitable areas in the Potential Area Analysis, while also considering Planned Power Corridors, Renewable Energy Development Zones and existing EIAs. The inter-regional transmission lines are clustered according to the supply areas, as illustrated in Figure 26 and Figure 27, with clustered transmission lines represented by different transmission capacities.

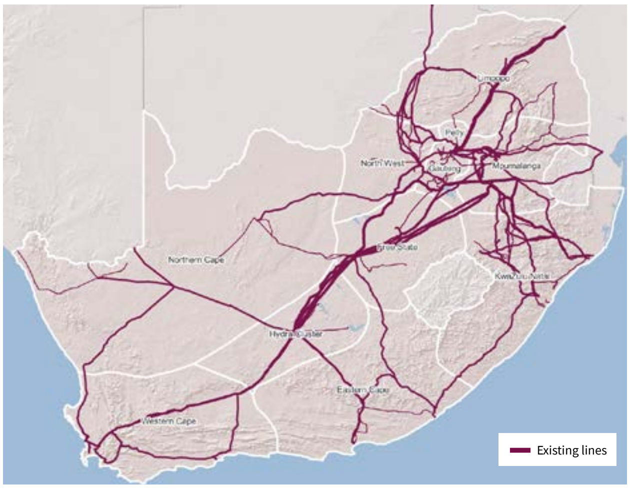


Figure 26: Dataset on the existing lines. Own illustration based on [29].

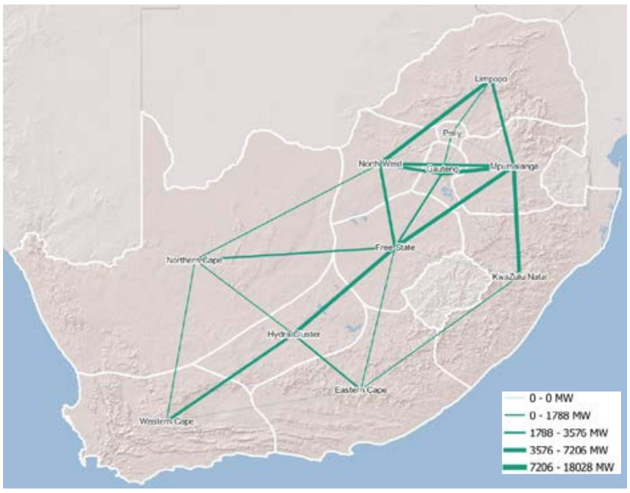


Figure 27: Clustering of inter-regional transmission lines. Own illustration based on [29].

The main transmission system (MTS) substations on the Eskom transmission network are grouped into one node per region. Lines that cross the regional boundaries contribute to the inter-region transfer capacity of the given region. Using the voltage and length of each inter-region transfer line, the St Clair calculation is computed for each line, and summed per node to determine the total inter-region transfer capacity. To consider N-1 constraints, either the largest capacity will be removed or thermal de-rating factors of 50% – 70% is applied (reducing the total transfer capacity by 30 – 50%) [81].

2.9 Representation of Sectoral Demands

Sectoral demands are critical inputs in energy system models as they provide insights into the specific energy requirements of various sectors (which in turn guides

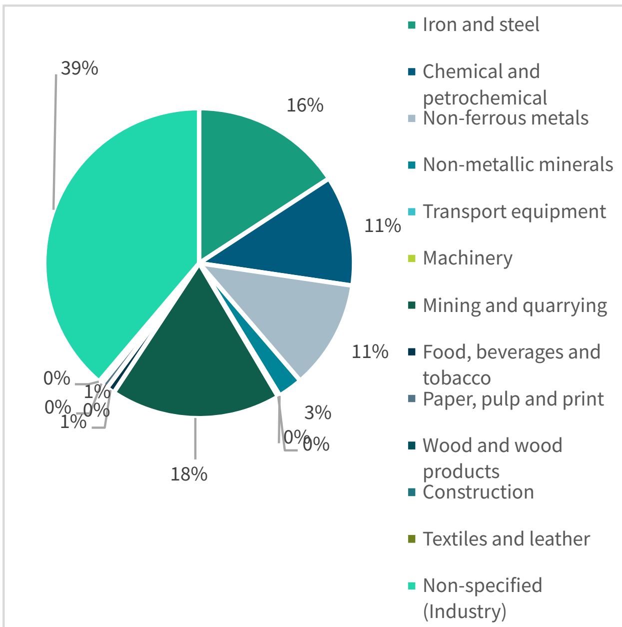


Figure 28: Share of Final Industry Consumption – DMRE Energy Balance 2021. Source: [85].

planning, policy formulation, infrastructure development, and technological innovation in the energy sector). The South African Department of Mineral Resources and Energy (DMRE) publishes annual commodity flows and energy balances, representing final sectoral energy demands. An example of the final energy consumption shares for the industry sector is presented in Figure 28. It can be seen from the figure that a large proportion of the demand is non-specified (53%). In addition to this, the data is published on an annual basis, whereas we require hourly temporal resolutions for the current study. This necessitated the use of additional published national statistics and studies to establish the shares of final hourly energy consumption per sector for base-year demand data.

Table 17 presents a summary of additional published national statistics related to energy demands for the transport, industrial, agricultural, residential and commercial sectors. These datasets can be utilised to adjust the DMRE energy balances through various bottom-up approaches to yield more complete approximations for the base-year energy balance data [45].

Table 17: Summary of sectoral demand data sources. Based on [48]

Sector	Data Sources
Transport	DMRE, NAAMSA (National Association of Automobile Manufacturers of South Africa), eNatis (National Traffic Information System), Natmap (National Transport Master Plan), SOL (State of Logistics report), South African Petroleum Industry Association (SAPIA), International Energy Agency (IEA)
Industrial	DMRE, Eskom electricity sales (by Standard Industrial Classification (SIC) codes), National Energy Regulator of South Africa (NERSA) municipal electricity distributed to industry, StatsSA, industry associations, annual reports, IEA
Agricultural	DMRE, IEP (Integrated Energy Plan, 2003), SAPIA, Eskom sales
Residential	DMRE, electricity consumption surveys, Stats SA, Eskom, National Income Dynamics Study (NIDS), All Media & Products Survey (AMPS), NERSA, SAPIA
Commercial	DMRE, Low Emissions Pathways Technical Report (2011), LTMS GHG mitigation strategy (2000), StatsSA, CBECS (2003), Annual City of Cape Town survey for registered industrial and commercial buildings, Eskom sales

The project team established a collaborative partnership with the Energy Systems Research Group (ESRG) at the University of Cape Town (UCT), who have worked extensively on the development of bottom-up approaches for projecting sectoral demands in South Africa to support generation expansion planning. The ESRG has built and continue to maintain the South African TIMES model (SATIM), a bottom-up energy system optimisation model which finds least cost energy pathways to meet future energy demand (with end-use technologies) given various constraints. SATIM includes a detailed representation of key components of the energy system, such as coal supply to power plants from mines, representation of intensive energy industries in terms of their process flows, representation of residential energy consumption for different income levels and electricity access, as well as commercial, agricultural and transport demands [33].

Hydrogen is included as a commodity in SATIM, produced and integrated into the energy system via several production pathways including coal gasification, natural gas or steam methane reforming (SMR), and water electrolysis with a platinum-based polymer electrolyte membrane (PEM)), distribution, and utilisation. This enables the analysis of hydrogen's role in meeting future local sectoral energy demands [48]. Due to the technical and process detail incorporated in the SATIM modelling framework, results have applied to the development of national policy responses to climate change [20, 33, 48, 86]. SATIM was also leveraged to provide technical support to the Presidential Climate Commission (PCC) in the development of the Just Energy Transition Investment Plan (JET-IP). The methodology for the JET-IP was based on previous technical support provided to the Department of Forestry, Fisheries and the Environment (DFFE) in updating South Africa's NDC in 2020/21, and initial analysis of long-term low-emissions development pathways towards net-zero CO_2 emissions around 2050. In addition to this, the ESRG group developed the demand projection model in support of the Draft IRP 2023.

While SATIM provides demand forecasts based on technologically detailed resolution, it currently runs as a single-node model for representative time slices [86]. Thus, it does not capture the spatial diversity of supply and demand. Given the existing bottlenecks in the transmission network, spatially disaggregated planning is advantageous when incorporating grid constraints. Moreover, the varied evolution of different sectors across geographic locations, influenced by growth and climate impact assumptions, further underscores the need for spatially detailed analyses. Not capturing this diversity affects the optimisation of the energy system, as power plants located far from demand centres do not incur a transmission penalty. Therefore, SATIM would benefit from being soft-linked with more geographically detailed models, presenting an opportunity for model coupling between PyPSA-RSA-Sec and SATIM.

In collaboration with the UCT team, the goal was to utilise validated input assumptions and develop consistent scenarios aligned with the JET-IP, reflecting the dialogue of key South African stakeholders and building upon progress made thus far. This approach ensures transparent presentation of energy demand across all sectors and allows for a reasonable estimation of electrification levels. Demand projection results from the JET-IP, which were obtained using the SATIM model, were used as inputs into the sector-coupled PyPSA-RSA-Sec model as already illustrated in the overview chapter in Figure 12. The following sections provide an overview of the representation of sectoral demands and the methodology employed leveraging SATIM to derive the demand profiles and projections.

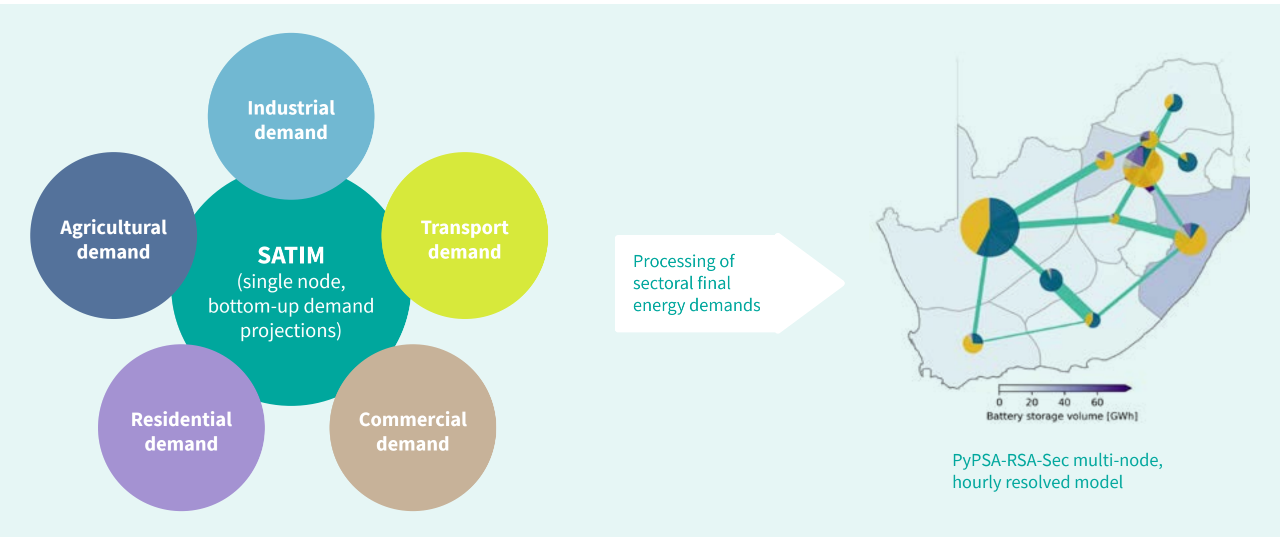


Figure 29: Demand projection results from SATIM used as inputs into sector-coupled, multi-node, hourly resolved PyPSA-RSA-Sec.

In South Africa, various data sources provide insights into secondary electricity, final electricity demand, and useful energy, each playing a distinct role in the energy system. Secondary electricity represents the sum of electricity sent out from large generators to the transmission and distribution grid, with hourly data published by Eskom [1]. Final electricity demand encompasses the consumption by various electrical devices and machinery, tracked by Eskom through monthly sales data categorized by Standard Industrial Classification (SIC) codes and reported annually [34]. As previously mentioned, the DMRE publishes annual commodity flows and energy balances (available up to 2021) [44]. The overall sectoral energy consumption published for 2021 is illustrated in Figure 30.

Municipalities report sales with varying detail and frequency, but NERSA has not published municipal sales data since 2012 [33]. Increasing on-site generation further complicates the observation of final electricity demand from a single data source. Useful energy, which drives final energy demand, is linked to indicators like population and GDP, and can be inferred from final energy data, appliance stock, vehicle and machinery efficiencies, and fuel use surveys [33].

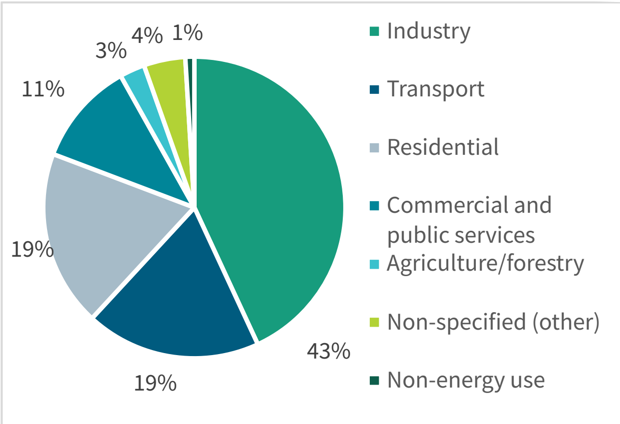


Figure 30: Share of Total Final Energy Consumption by Sector published by DMRE. Source: [85].

SATIM is a multi-sector, multi-period, single region (national), least-cost optimisation model that can be applied to solve future energy demand projections. The model, based on the TIMES (The Integrated MARKAL-EFOM System) framework, is a bottom-up, end-use model that simulates the entire economy's energy-related emissions, including pollutants such as NOx, SOx, CO_2, CH4, N2O, and PM10 [48].

The modelling approach considers the complex interactions between sectors and major drivers such as population and economic growth, as illustrated in Table 18. Five demand sectors (industry, agriculture, residential, commercial, and transport) along with two supply sectors (electricity and liquid fuels) are considered. Within each sector, energy demand is expressed by technology or fuel grouping, with sectors disaggregated into end-uses at technology level, depending on data availability [Energy Systems Research Group, "Developing an Integrated Energy Plan in the South African context-a methodological framework," 2024.], [48]. The base year and projected energy demands are exogenously defined, focusing on the useful energy requirements for each sector and anticipated energy service demands over time.

Future final demands are endogenously shaped by efficiency, technology and fuel costs, learning rates, retirement schedules, economic interactions, population growth and income growth within the model. [48, 86]. Figure 31 provides a schematic summary of the SATIM model components.

The high-level sectoral detail in SATIM aligns with the energy balances published by the DMRE where feasible. Energy consumption in the base year deviates from the DMRE energy balances when other national statistics suggest necessary adjustments, ensuring accurate classification and representation of base year demands [48, 86]. Reference year data for year 2021 is summarised in the following sections of this chapter for the transport, industry, commercial, residential and agricultural sectors. The trajectories of these demands based on selected scenario pathways is discussed in further detail in section 3.5.

Table 18: Summary of economic sector representation in SATIM and their main drivers [45].

Economic sector	Subsector disaggregation	End-Use disaggregation	Demand driver
Agriculture	None	Irrigation, heating, processing, traction, other (lighting, cooling etc)	Sectoral GDP
Residential	High, medium and low- income electrified households	Cooking, water heating, space heating, refrigeration, lighting, other	Population, household income, electrification rate
	Medium and low-income non-electrified	Cooking, water heating, space heating, lighting	
Commercial	None	Cooling, space heating, cooking, lighting, refigeration, water heating, public lights, public water	Sectoral GDP, building stock
Industrial	Iron and steel, ferroalloys	Tonnes produced by industrial processes	Sectoral GDP
	Aluminium, non-metallic minerals, pulp and paper		
	Mining, chemicals, food, beverages, tobacco, precious and non-ferrous metals, general manufacturing	Boiler and process heating, cooling, HVAC, lighting, fans, pumping, compressed air, electrochemical and other electrical services	
Transport	Air, freight and pipeline	Freight tonne km by rail and road (one light vehicle class, nine heavy vehicle classes)	Transport GDP, population, household category and income
	Private passenger	Passenger km travel by cars, SUV, motorbikes	Household income
	Public passenger	Passenger km travel by bus, train, minibus, BRT	Household income

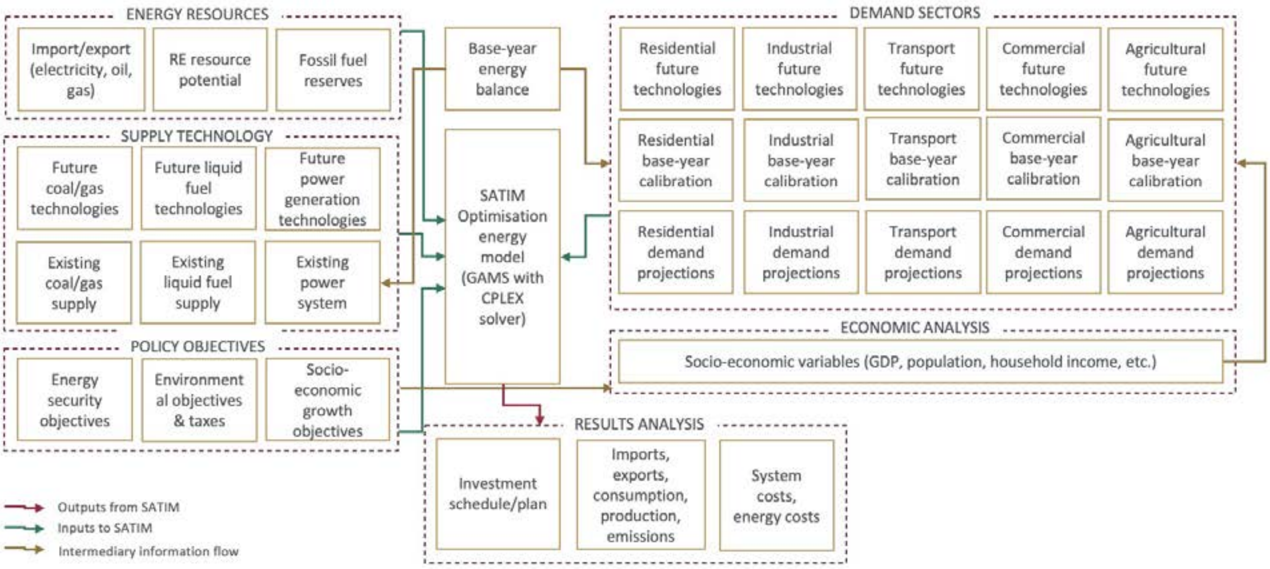


Figure 31: Schematic representation of SATIM redrawn from [48].

2.9.1 Transport

The transport sector encompasses energy consumption for passenger and freight transport via road and rail, as well as for pipeline transfers and aviation. Freight road transport is categorised by vehicle class (LCVs and HCVs class 1 to 9) and fuel type (diesel, petrol, electricity, or hydrogen) in SATIM. Passenger road transport is divided into private and public transport, further classified by vehicle class and fuel type. Passenger rail is assumed to be fully electric. Passengers are segmented by income levels (high, medium, and low), with specific assumptions regarding private vehicle ownership, number of vehicles owned per person, average occupancy of private vehicles, annual mileage, annual travel time, and average speed of both private and public vehicles. Freight rail is assumed to be currently powered by a combination of diesel and electricity, with all new freight rail projected to be electric. Aviation is treated separately, without distinguishing between passenger and freight transport [27, 48, 87].

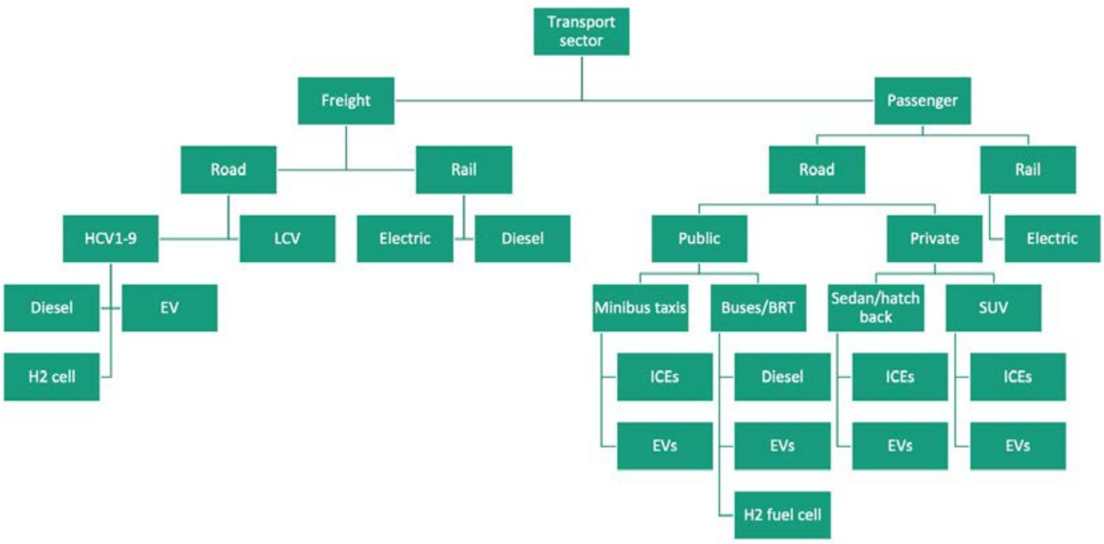


Figure 32: Transport sector categorisation in SATIM. Own illustration based on [88].

The energy demand for passenger and freight transport is primarily influenced by vehicle-kilometres travelled and travel efficiency. Vehicle-kilometres are driven by societal and economic needs to transport people and goods. Conversion efficiency varies by vehicle type, fuel, vehicle age, and utilisation patterns [48, 87]. Energy service demand is measured in passenger-kilometres (pkm [11]) and tonne-kilometres (tkm [12]) [88]. Passenger demand is mainly driven by population and household income, influencing car ownership and the private/public transport share.

Freight vehicle-kilometres are linked to sectoral GDP growth, with rail freight included in the "Traction" sector [33, 48]. For both passenger and freight road vehicles, constant occupancy and load factors were assumed, while vehicle efficiencies are projected to improve by 1% annually [48]. The electrification of road transport is managed to ensure vehicle charging occurs outside peak demand times. The pace of electrification is expected to accelerate post-2030 due to GDP growth and increased transport electrification. SATIM determines the optimal fuel type for new vehicle purchases annually to meet demand, updating the country-wide vehicle stock accordingly [33, 48, 87, 88]. An overview of the transport sector model is provided in Figure 33.

Scrappage factors remove aging vehicles from the fleet, with vehicle activity declining through decay rates. As fleet numbers and activity decrease, new vehicles are purchased based on discounted costs (including vehicle and fuel expenses) to meet vehicle-kilometre demand. The model selects from available vehicle types within each class. For aviation, fuel demand correlates with GDP without modelling specific technologies [48, 87].

The energy sources for transport technologies in the reference year are shown in Figure 34. Historical values for international marine bunkering and domestic navigation were obtained from the United Nations Statistics Division (UNSD) to approximate shipping energy demands [89].

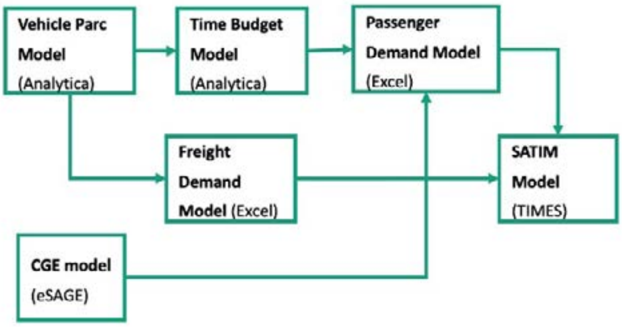


Figure 33: Overview of transport sector model. Own illustration based on [48, 87].

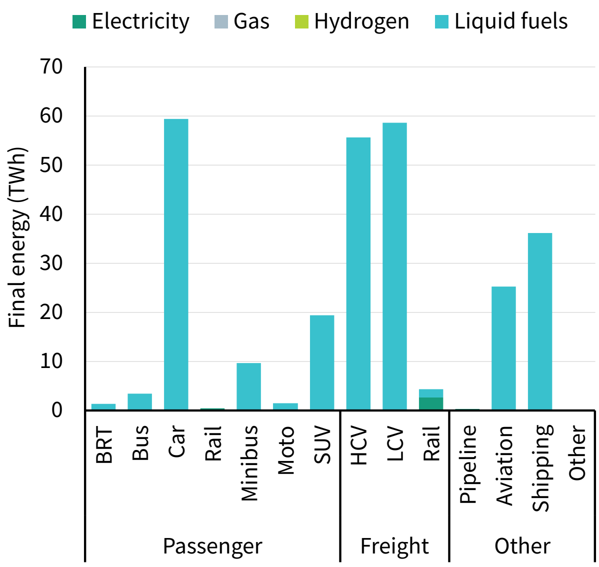


Figure 34: Reference demand for the transport sector (2021). Own illustration based on [20].

2.9.2 Industry

Industry modelling by the ESRG is divided into two methodologies. Methodology one applies to large, energy-intensive facilities where processes are characterised, while methodology two applies to smaller, more dispersed industries. The sub-sectors for these categories are listed in Table 19. Methodology one covers large operations like blast furnaces, cement kilns, and paper mills, which are reported in terms of fuel use, energy intensities, and operations. Methodology two classifies smaller sectors by energy end-use requirements such as process heating, pumping, machinery, and lighting, calibrated with national energy balance data [86, 88].

11 where 1 pkm is equivalent to 1 passenger travelling 1 kilometre
12 where 1 tkm equals 1 tonne transported 1 kilometre

Table 19: Methodologies used to model industrial consumption. Based on [86, 88].

Method	Sub-sector	Details
One	Iron and steel	All primary, and secondary producers of crude steel, coke production included here (which is sold to chrome industry)
	Ferro alloys	FerroChrome, and FerroManganese
	Aluminium	One company and one facility in South Africa: South32's Hillside smelter near Richard's Bay
	Pulp and paper	
	Non-metallic minerals	Cement, bricks, lime, glass
	Platinum Group Metals (PGMs)	Includes mining of the ores
Two	Mining	Includes coal mining, excludes PGM ores
	Chemicals	Energy use for chemicals, including petrochemicals, but not liquid fuels; the subsector is closely linked to, and dominated by, the operations of Sasol
	Other precious and non-ferrous metals	Gold, copper, nickel, zinc, and others, excludes PGMs
	Food and beverages	Processing of agriculture products into food products, includes sugar industry
	Other general manufacturing	Production of general other goods (textiles, clothing, pots and pans etc.)

The Ferroalloys sector includes the production of Ferro-Chrome, Ferro-Silicon, Ferro-Manganese, and other Manganese alloys. Ferro-chrome (which dominates ferro-alloy production in South Africa) is used in the manufacture of stainless steel. The majority of energy consumed in the production of ferro-alloys is used in electric arc furnaces, which heat a mixture of ore, fluxes and reducing agents (coke and/or coal) for smelting into metal alloy products [45]. Process inputs include electricity, coal and coke. Due to the difficulty of accessing information and data for this sector, the ferroalloy industry (excluding aluminium) is represented by a single technology, the electric arc furnace, in SATIM [48].

The iron and steel sector produces steel using various technologies and fuels. Input materials include electricity from the grid, coking coal, coal, gas, oil products, biomass and waste fuels. Existing technology capacities and new technology additions are explicitly represented in the SATIM model. Existing technologies include the Blast Furnace (BF), Basic Oxygen Furnace (BOF), Direct Reduced Iron (DRI), Electric Arc Furnace (EAF), MIDREX (a gas-based shaft furnace process that converts iron oxides (pellets or lump ore) into DRI), CONARC (combines electrode arc melting with the oxygen steelmaking process), onsite generation, combined heat and power (CHP) units and coke ovens. Existing plants can be retrofitted for improved efficiencies, while new technologies enable higher production efficiency at new plants in the model. Gas DRI-EAF and BF-BOF with Carbon Capture and Storage (CCS) are additional new technology options available in SATIM for future steel production [48].

Table 20: Efficiency and utilisation assumptions for the iron and steel industry. Based on [90, 91].

Iron & Steel Technology Description	Efficiency (sum OUT/IN)	Utlisation (Fraction)
Elec Heating - Electricity	1	0.114
Compressed air - Electricity	0.05	0.116
Lighting - Electricity	0.3	0.125
Cooling - Electricity	2	0.130
HVAC - Electricity	0.9	0.132
Pumping - Electricity	0.8	0.121
Fans - Electricity	0.8	0.109
Other motive - Electricity	0.8	0.131
Electrochemical - Electricity	0.76	0.132
Boiler/process heating - Coal	0.64	0.154
Boiler/process heating - Gas	0.72	0.154
Boiler/process heating - Oil HFO	0.68	0.154
Boiler/process heating - Oil LPG	0.72	0.154
Boiler/process heating - Electricity	0.76	0.154
Boiler/process heating - Waste	0.6	0.154
Ancillary - Coke	1	0.154

The Aluminium sector is distinct within the non-ferrous metals category in SATIM and is represented as a single technology primarily using electricity to produce aluminium, along with related process emissions. This sector is a significant electricity consumer and operates independently from the broader non-ferrous metals industry and the South African economy. It is assumed that aluminium production in South Africa remains stable, with most of the output exported. Variations in export and domestic demand are expected to balance each other out. The non-metallic minerals sector includes the production of cement, glass, lime, and bricks [48, 86].

The pulp and paper (P&P) sector produces paper, paper products, and dissolving pulp. Steam is a critical component of the energy and process systems for the P&P sector. Biomass residue and production waste are often used as feedstocks for boilers in the pulping process [48].

The estimate of reference year demand for final energy services is calculated for each industry subsector in SATIM, drawing assumptions from literature, energy audits, and surveys [48, 86]. The primary energy uses are process heat and machinery operation. Machinery operation relies largely on electricity, while process heat is supplied by a combination of coal, gas, electricity, and liquid fuels. Although electricity might increasingly be used for low-grade heating with heat pumps, coal remains economically advantageous for medium to high-grade heat demands. The use of natural gas in industry could grow if infrastructure develops but will need to make economic sense relative to locally abundant coal [88].

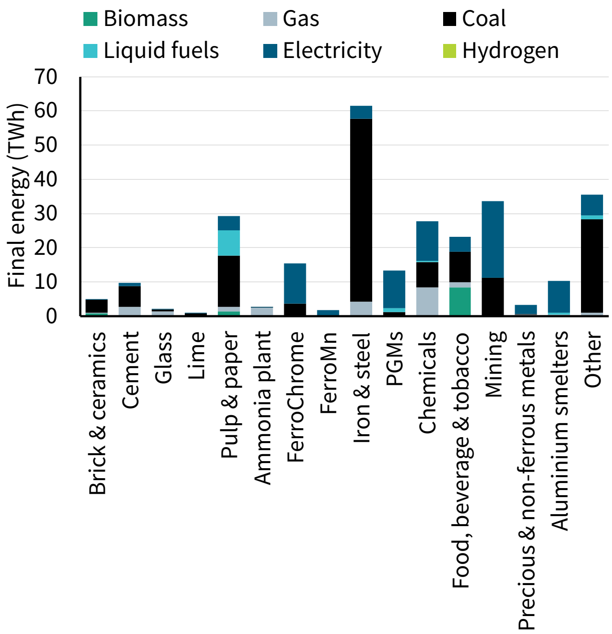


Figure 35: Reference energy demand for industry sub-sectors (2021). Own illustration based on [20].

2.9.3 Commercial

The commercial sector encompasses wholesale, retail, motor trade services, warehouses, industrial spaces, office buildings, banking facilities, schools, hospitals, hotels, and recreational facilities. Public sector floor areas include public services like lighting and water. Energy demand is estimated based on energy intensity per square meter, floor area growth, and improvements in energy efficiency from building codes. Final energy demand is calculated considering the efficiency and penetration of technologies providing energy services. Buildings are categorised into existing and new, with new buildings adhering to updated regulations and contributing to the overall stock while replacing aging infrastructure. Growth in floor area correlates closely with GDP growth, lagging by about two years, with floor area changes reflecting approximately 70% of GDP growth limitations [48, 86].

Energy services in new buildings are more efficient due to newer technologies, while older buildings face limitations [33, 48]. New building floor area therefore increases at the rate of commercial floor area growth plus the loss in existing floor area. Energy services are disaggregated into cooling, space heating, cooking, lighting, refrigeration, water heating, public lighting, public water supply, and other appliances. Figure 36 illustrates the final energy demand for each energy service represented.

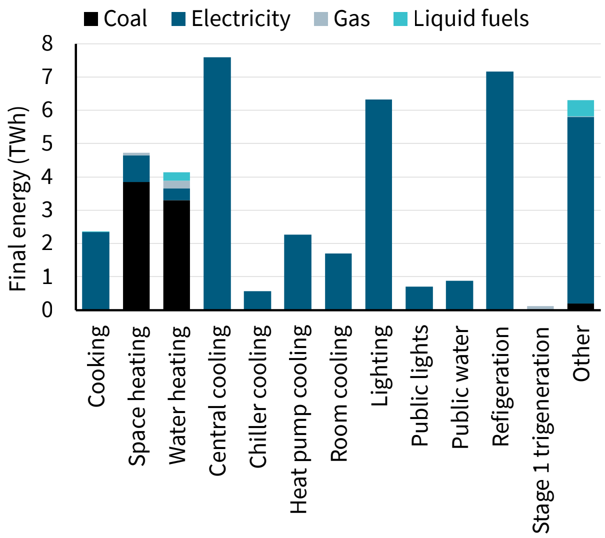


Figure 36: Reference demand for the commercial sector (2021). Based on [20].

2.9.4 Residential

The residential sector in SATIM captures changes in fuel, technology-use and energy service demands, which are all influenced by variations in income levels. Each household group has distinct energy service demands, technology penetrations and associated average efficiencies. SATIM disaggregates households into three levels by income and electrification status, allowing for the incorporation of policy interventions and mitigation actions targeting specific groups such as increased electricity tariffs for high consumers or solar water heating programs for lower-income households. High-income households have higher electricity demands and appliance ownership than middle and low-income groups, with the latter often using multiple fuels with low overall consumption. [48, 86, 88]

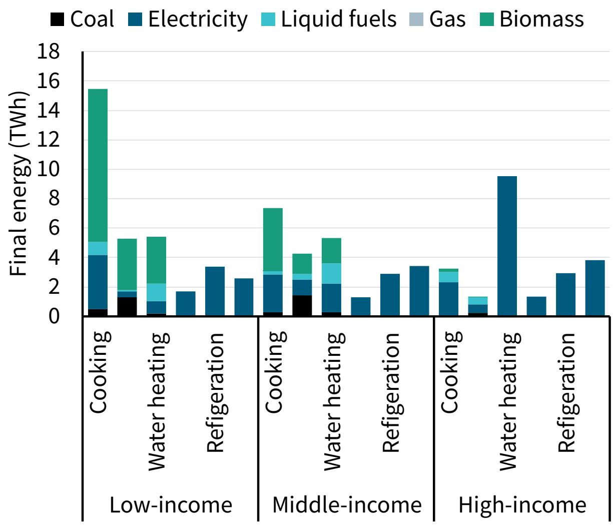


Figure 37: Reference demand for the residential sector (2021). Own illustration based on [20].

The residential sector's representation is limited by data availability. Energy demand projections consider population and income growth, household size, and electrification program success. Data is primarily sourced from national surveys (including the IES and Census). Large national surveys are combined with smaller, behaviour-focused surveys to match income groups to fuel-use and appliance ownership. An exogenous projection of electrification rates is necessary to derive household splits between electrified and unelectrified households, based on historical trends and future targets. [48, 88]

Table 21: Electrification rates by income group. Based on [48].

Income group	2020	2030	2040	2050
Low income	71%	80%	85%	95%
Medium income	83%	90%	95%	100%
High income	100%	100%	100%	100%
Overall electrification	81%	90%	95%	99%

The energy sources supplying each end-use per income group for the residential sector are categorised into cooking, space heating, water heating, lighting, refrigeration and 'other', as illustrated in Figure 36.

2.9.5 Agriculture

Although the agricultural sector has a relatively small energy demand, it plays a crucial role in the South African economy. The sector's energy use is categorised into five services, including traction, irrigation, heating, processing, and miscellaneous purposes such as lighting and cooling. Diesel is the predominant energy source, accounting for over half of the sector's consumption [86]. Electricity exclusively supplies the 'processing' and 'other' categories, while traction relies on diesel but can transition to electricity after 2025. Heating is mainly provided by paraffin, with minor coal usage, which can shift to electricity, gas, or alternative fuels post-2025. Irrigation is primarily powered by electricity, supplemented by diesel, with a potential complete transition to electricity by 2030 [88].

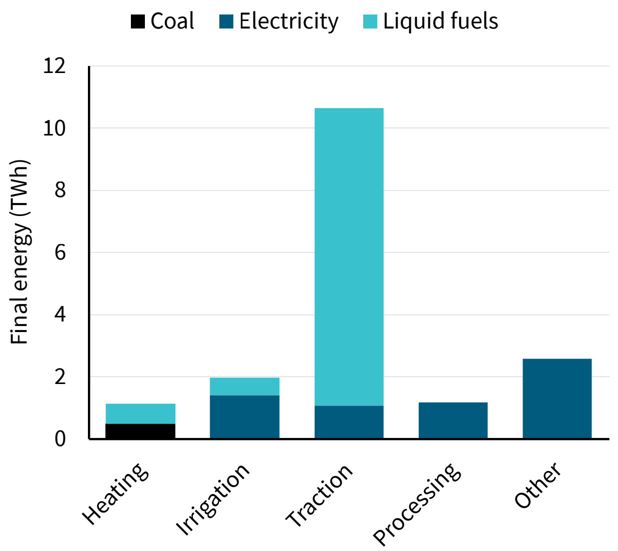


Figure 38: Reference demand for the agricultural sector (2021). Own illustration based on [20].

2.9.6 Spatial Information for the Regional Allocation of Demand Data

The national demand projection data obtain from ESRG for the JET-IP analysis was not sub-regionally resolved, therefore we regionalised the data with geospatial datasets. Geospatially explicit locations and capacity information was used to spatially disaggregate the cement industry, iron and steel industry, aviation, and maritime transport as illustrated in Figure 39 and Figure 40. Gridded population and gross value-added datasets were utilised to distribute all other sectoral demands into the model nodes.

It was assumed that the export volume targets for NH3 and Fischer-Tropsch fuels can be met via all regions with a coastal line, where the necessary export infrastructure will be built in the future at existing ports or at a new port in Boegoebaai.

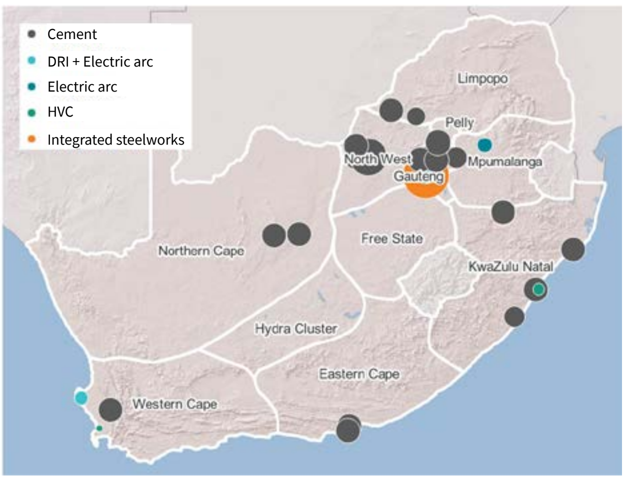


Figure 39: Illustration of geospatial asset-level information for industries used for the regionalisation of sectoral demands. Own illustration based on [92–95].

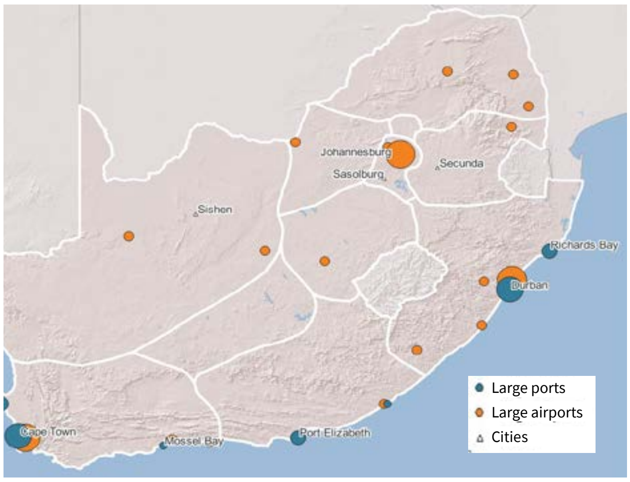


Figure 40: Illustration of geospatial asset-level information for ports or airports used for the regionalisation of sectoral demands. Own illustration based on [96, 97].

3 Scenario Definition

3.1 Overview

The existing state of the energy system is marked by significant uncertainty as the global energy landscape undergoes transformative shifts. This uncertainty is further compounded at the local South African level by concerns regarding the performance of Eskom's generation fleet, grid reliability, regulatory frameworks, and policy directions. Effective planning in such uncertain environments emphasizes the importance of bolstering system resilience.

As described in the previous chapter in detail, the optimisation process aims to minimize investment and operational costs while adhering to specified constraints tailored to a given scenario pathway. Exploring alternative pathways grounded in different assumptions is crucial for expansion planning, particularly given the inherent uncertainty involved in forecasting parameters like technology expenses, evolution of sectoral demands, renewable energy expansion limitations, grid constraints, coal plant performance, fuel costs, export potentials and potential future climate policies and instruments, such as carbon taxes. To quantify the impact of uncertainties in medium to long-term projections, we explored three scenario pathways together with a set of sensitivities. Each scenario reflects a different set of assumptions about policy measures, market developments, and technology expansion constraints. The scenario results will be essential for exploring various pathways and their implications on the total system costs, export opportunities, expansion requirements and the suitability of the energy transition.

The pathways developed demonstrate how and which PtX products can contribute to the decarbonisation of power, transport, and industrial sectors, as well as considering the export potential of PtX products. Table 22 highlights and explains the identified key drivers considered when defining relevant scenarios.

Table 22: Description of the identified key drivers and configurations of the scenarios.

Key configuration	Description
CO_2 Policy	Defines the annual CO_2 limit, the CO_2 price and the coal phase-out path for the ESKOM coal-fired power plants
PtX export	Defines export volumes and prices considering domestic project realisations as well as global market demand and ramp-up scenarios
Wind, PV expansion	Defines the national or regional restrictions on the expansion of wind power, photovoltaics and other generation, conversion or storage technologies

Grid expansion	Sets out the restrictions on the expansion of the electricity transmission grid based on total line volume (TWkm)
Transport sector	Defines the development of the passenger and freight vehicle fleet, and of shipping and aviation demands.
Industry sector	Defines the development of the industrial sectors, the growth of the sectors, and the demands per production route.

Table 23 illustrates the three scenario pathways that were defined for the study, which are the Current Policy (CP), Resilient Net-Zero (NZ) and NZ + High and Early Export scenarios.

Scenario CP: Current Policy

The Current Policy scenario adheres to existing policies without introducing stringent new CO_2 limits. The scenario incorporates the planned CO_2 price trajectory (see below), and envisages a gradual phase-out of coal-fired power plants as planned by ESKOM. The coal phase-out is slower compared to the other two scenarios. However, it is important to note that the expansion of renewables was not limited globally (wind and solar PV expansion is regionally constrained, particularly in the four western regions of South Africa, reflecting current substation and distribution grid limitations) and is optimised under the defined conditions. The transmission grid under this scenario is expected to see only a modest increase in capacity, with a 10% expansion of existing inter-regional transmission capacities, aimed at supporting gradual integration of new capacities by 2050. This expansion volume is considered feasible and is the same in all three main scenarios. The scenario sees a slow progression of the PtX market, with limited exports capped at 10% of the export-oriented scenario NZEE. This impacts the expansion of these technologies domestically. In the transport and industry sectors, transitions to efficiency and new technologies are delayed, suggesting a slower adoption of modern technologies like electric vehicles, efficiency improvements and low-carbon technologies such as DRI in steel production.

Scenario NZ: Resilient and Efficient Net-Zero

The Resilient and Efficient Net-Zero scenario (NZ) is designed with a strong focus on achieving a sustainable transition of South Africa's energy system, aligned to a global net-zero path. This is achieved by implementing a robust CO_2 reduction policy that includes annual CO_2-targets in line with a global net-zero ambition and an accelerated phase-out of existing coal-fired plants by 2040. The annual targets are taken from the modelled pathways presented by the Climate-Action-Tracker [98]. It should be noted that the pathway consistent with a global net-zero trajectory (in compliance with the IPCC global warming report for the net-zero scenarios) rapidly reduces emissions but still allows for South Africa to emit CO_2 in 2050 (see next section for further details). Despite these ambitious CO_2 policies, the scenario assumes a conservative stance towards the development of the global PtX market potential, mirroring the Current Policy scenario's projections. The wind and solar PV policies also reflect those of the CP scenario, with regional expansion constraints in the western regions. The transmission grid expansion is aligned with the CP scenario's approach, maintaining the of 10% existing inter-regional transfer capacity expansion by 2050. The transport and industry sectors under this scenario are characterized by an ambitious shift towards more efficient, cleaner technologies, a proactive adoption of electric vehicles and energy-efficient industrial technologies, marking a significant deviation from the CP scenario. In contrast to the CP scenario, this scenario assumes a gradual replacement of fertiliser imports by domestic green ammonia and fertiliser production.

Scenario NZEE: Net-Zero + High and Early Exports

In the Net-Zero + High and Early Exports scenario, the ambition for a net-zero future is maintained as in the NZ scenario, but with a significant emphasis on boosting the PtX market through high exports. All domestic PtX export projects are expected to come online by 2030 as announced, which positions South Africa as a major player in the global PtX market. This scenario allows for the unrestricted expansion of wind and solar projects. This is justified through the possibility of both grid-connected and off-grid generation [13] for hydrogen production. It is also conceivable that PtX projects in regions with limited substation and grid capacities support the expansion of these. Despite the ambitious strategies for renewable energies and PtX, the limit for the overall expansion of the transmission grid of 10 % does not deviate from that of the CP scenario. This allows the comparative analysis to focus on the influence of the other parameters. On the other hand, it is assumed that the regional expansion of the distribution grid and the construction of substitutes are prioritised. As with the NZ scenario, the transport and industry sectors are poised for rapid transformation, focusing on transitioning to newer and cleaner technologies that support South Africa's net-zero emissions goal. Similarly, fertiliser imports are replaced by domestic green ammonia and fertiliser production.

Table 23: Summary of three main scenario pathways CP, NZ and NZEE explored in the study.

Key drivers	Current Policy (CP)	Resilient Net-Zero (NZ)	NZ + Early Export (NZEE)
CO_2 Policy	No budget limits, CO_2-price, ESKOM plans for coal phase-out	50MtCO_2 in 2050, 8.3 GtCO_2 budget, CO_2 price, Coal phase-out by 2040	= NZ
PtX export	Delayed and low exports (10 % of High), Products: Ammonia, Fischer-Tropsch fuels	= CP	High exports for Ammonia and FT fuels, all projects go online as announced
Wind, PV expansion	**2030 →** Limits for four western regions, otherwise free expansion	= CP	Free expansion, assuming on- & off-grid generation
Grid expansion	Limit of + 10 % existing inter-regional transmission capacities up to 2050	= CP	= CP
Transport sector	Delayed transition of efficiency, modal shift, and new electric vehicles	Ambitious transition to efficiency, modal shift, and new electric vehicles	= NZ
Industry sector	Delayed transition to innovative technologies (e. g DRI) and efficiency	Ambitious transition to innovative techs & higher domestic fertilizer production	= NZ

13 Off-grid generation is not explicitly modelled in the model, but the model results show that a large proportion of the electricity generated for PtX generation is also consumed in the regions themselves.

3.2 Carbon Policy

The Paris Agreement and increasing impacts of climate change are driving a global climate mitigation agenda, influencing markets and ultimately impacting economic competitiveness. Efficient, inclusive and fair CO_2 regulation is particularly important for South Africa with its carbon-intensive economy.

The carbon policy instruments considered in this study, which can be defined for each of the planning horizons, are annual CO_2 caps, CO_2 prices and a phase-out of coal-fired power plants. It should be noted that the modelled system considers CO_2 for fossil fuels and not the other greenhouse gas emissions.

3.2.0 CO_2 Limits

Experience has shown that CO_2 budgets or upper limits for specific years is one of the main constraining and decisive parameters for an energy system optimisation and planning exercise. At the same time, the definition of GHG emissions (greenhouse gas emissions) and the derivation of target values for CO_2 emissions is a politically and methodologically challenging task. As with most assumptions, the CO_2 limits for 2030 to 2050 in this study are defined as far as possible based on existing policy targets, South African specific approaches reported in literature and available data.

Existing policy targets and literature

South Africa submitted its updated Nationally Determined Contribution (NDC) for 2030 in September 2021 [99]. The communicated conditional target range for greenhouse gas emissions is 350-420 $MtCO_2e$ by 2030 incl. negative LULUCF, or an estimated 366-436 excl. LULUCF according to Climate Transparency [100]. This goal is subject to conditions and depends on the level of international funding. The ESRG technical report on South Africa's NDC targets for 2025 and 2030 [101], prepared for the Presidential Climate Commission and the DFFE, used the Climate Action Tracker (CAT) and the Climate Equity Reference Calculator (CERC) to initially define a "fair share" budget [14] for their modelling exercise. These two instruments are also used in other studies and are well established. The main part of CAT methodology is to derive country-specific GHG budgets based on global IPCC scenarios [15].

In addition to the NDC target range for 2030, the President has communicated continued commitment to net-zero by 2050 and recently signed the Climate Change Bill into law. This lays the foundations for ambitious long-term CO_2 reductions. However, it is still unclear what the 2050 commitment means in the context of South Africa's fair share of a global net-zero pathway. The following uncertainties thus need to be considered on the path to net-zero:

- How will LULUCF emissions develop? According to CAT, the average value for LULUCF from 2011 to 2020 is -17 MtCOeq/yr, but the range across all years listed is from -33 MtCOeq/yr in 2016 to +14.8 MtCOeq/yr in 2008.
- What is the trend in GHG emissions from agriculture and waste, which are difficult to avoid without behavioural changes?
- Since the CAT budgets are derived from IPCC scenarios, they assume limited overshoot and CO_2 removal methods. How much removal will be achievable in South Africa and globally?
- A report by E. Tyler et al. in 2022 on deriving sub-global net-zero targets raises the question of whether net-zero target dates should be treated flexibly for South Africa. Additionally, given the long-term uncertainties beyond the 2050 time horizon, should CO_2 budget allocations for energy system analyses also extend to 2060 or beyond? [102]

---

14 There are no established guidelines defining what constitutes a fair contribution to the global climate effort that considers aspects such as equality, responsibility, capability, and cost effectiveness [98].

15 CAT started to use the IPCC AR6 scenario database from September 2023 and updated the numbers for South Africa in March 2024 [98].

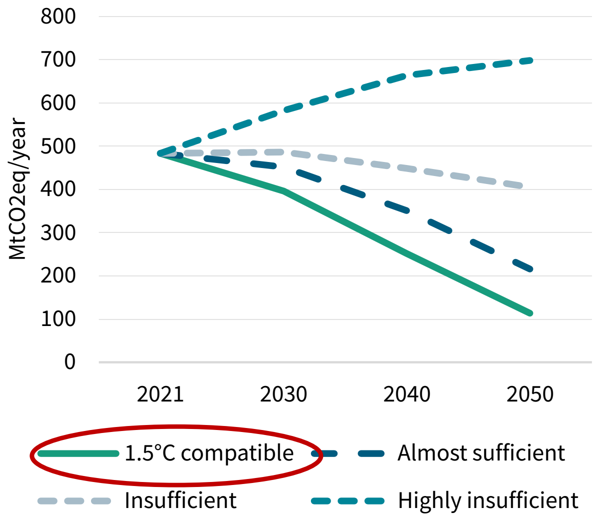


Figure 41: CAT assessment of the emission trajectories for South Africa for different modelled domestic (based on global) pathways in CO2equivalents. Own illustration based on [98].

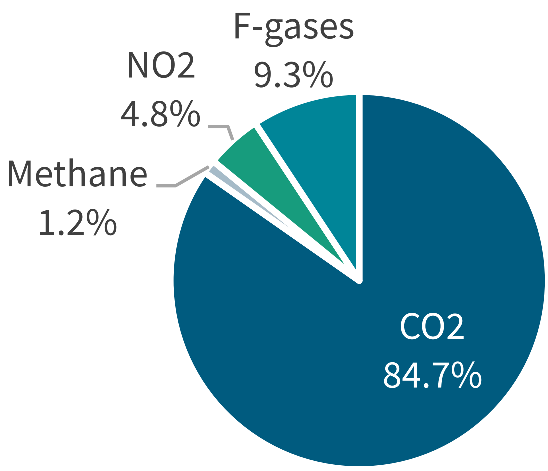


Figure 42: South Africa's shares of the various greenhouse gas emissions in 2017. All gases were converted to CO2eq. Own illustration based on [102, 103].

Deriving CO_2 limits and targets for the net-zero scenarios (NZ, NZEE) of this study

As in the ESRG technical report for the 2021 NDC update, this study will use the Climate Action Tracker sub-global downscaled pathways. Figure 41 presents the Climate Action Tracker's (CAT) assessment of historical emissions in $MtCO_2$/yr together with modelled pathways excluding LULUCF for 1.5°C compatible, almost sufficient, insufficient, and highly insufficient scenarios. As presented in the Stakeholder workshops during this project, the 1.5 °C compatible modelled pathway (later called CAT MP) with an ambitious, national budget of 8.3 $GtCO_2$ (9.7 $GtCO_2$eq) from 2020 until 2050 in compliance with the IPCC global warming report for global net-zero scenarios [98] is selected for this study.

For the system boundary of the model, the CO_2 emissions from fossil resources are derived from these GHG emissions in CO_2eq. Then, a range for net-zero CO_2 targets by 2050 is proposed. Finally, we pick a trajectory from this range. The calculation involves the following steps and the trajectories are visualised in Figure 43:

- Subtract GHG emission of agricultural excl. energy (39.6 $MtCO_2$eq/yr) [100], waste emissions.
- (25 $MtCO_2$eq/yr) [100] and negative LULUCF emissions (-17 $MtCO_2$eq/yr) from the 1°5C compatible GHG emissions pathway (CAT MP).

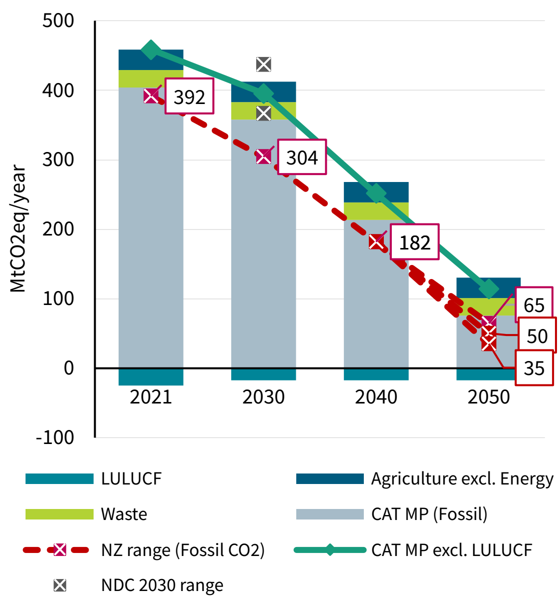


Figure 43: Trajectories for the GHG emissions of LULUCF, agriculture excl. energy, waste, derived CAT modelled pathways (CAT MP), and the calculated CO2 emission trajectory for net-zero ambitions (NZ range).

- Next, the CO_2 fraction of the GHG trajectory is calculated using the South African specific statistics presented by DFFE (see Figure 42). This results in 65 $MtCO_2$/yr).
- Finally, uncertainties in the evolution of LULUCF, waste and agriculture are considered in two steps. This results in targets for 2050 of 50 Mt/yr and 35 Mt/yr.

According to this CO_2 pathway, derived from the pathways modelled by CAT, South Africa will still be emitting 35-65 Mt CO_2 per year in 2050. However, according to the IPCC scenarios, which extend to 2100, South Africa could need to continue to reduce emissions in the following years. Furthermore, it would be optimistic to assume the highest value of the range for the main scenarios in this study due to the uncertainties listed before. Hence, **the CO_2 trajectories for the main scenario of this study end at 50 Mt per year**. The impact of higher or lower emissions **(65 and 35 Mt/yr)** is analysed in a **sensitivity run**. This sensitivity is important as it illustrates the 'last mile' efforts needed for lower emissions or for just after 2050. The sensitivity run could reveal the effects of stranded investments that could result from long-term investments in fossil-based assets during the transition process.

It should be noted that the trajectories of the CAT model paths were last updated in March 2024. This update was only considered after the last stakeholder workshop for this project.

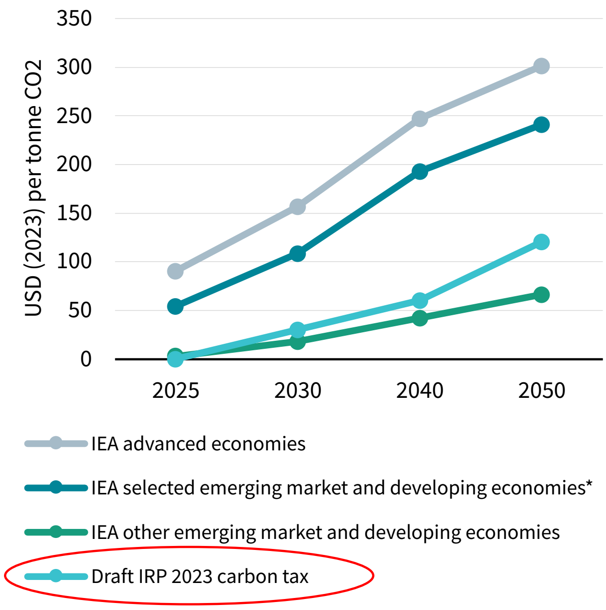


Figure 44: Carbon pricing published by the IEA and Draft IRP 2023. Own illustration.

3.2.1 CO_2 Price

In alignment with South Africa's carbon tax policy and the anticipated influence of international carbon pricing, we apply a carbon price that follows the headline tax rate based on the National Treasury's guidance, in line with the IRP 2023 draft carbon tax [27]. The South African carbon tax rate is significantly lower than international carbon prices in countries with net-zero targets [28, 104]. Using the headline rate provides a conservative estimate of future carbon pricing. This is likely to affect South African exports, as electricity will be subject to carbon pricing both domestically and internationally.

3.2.2 Coal Fleet Decommissioning

Expected capacities for coal, nuclear, OCGT, CCGT, pumped storage, and hydro were published in the JET-IP up to 2026, with consideration of the planned Eskom coal plant retirements. However, publications have since been released that signal a departure from these forecasts, with potential continued operation of coal-fired power stations in the longer-term [27, 105]. The Draft IRP 2023 provides Eskom's decommissioning schedule at a unit-level per station (typically with six units per station). The units were grouped to represent stations as two to three generators with different decommissioning dates to reduce computation costs and complexity in the PyPSA-RSA model [28].

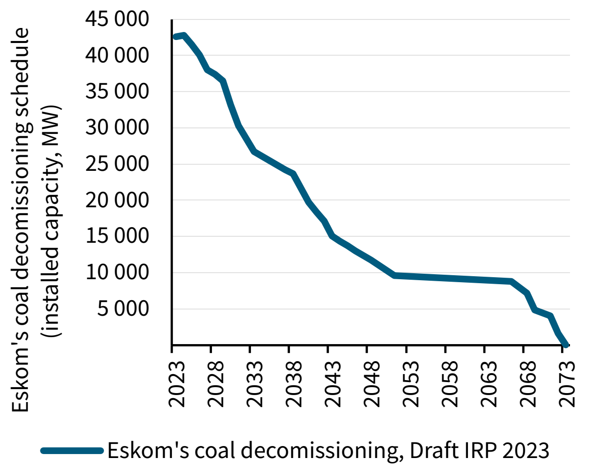


Figure 45: Eskom's coal decommissioning schedule as published in the draft IRP 2023. Own illustration based on [27].

An alternative decommissioning schedule is implemented for the net-zero scenarios (CO_2 budget of 6.7Gt from 2020 to 2050), with an accelerated retirement of the coal fleet, phasing out all coal by 2040, to facilitate a faster decarbonization of the power system. Decommissioning of all other existing technologies is based on the technical lifetime of the projects.

3.3 PtX Export

We align the export volumes of the NZEE scenario with optimistic values of the GHCS and reported export ranges published in literature, such as the NBI studies [10, 20, 68]. The potential export values amounted to 3mtpa (99 TWh/a) by 2040, with up to 5.8mtpa (193 TWh/a) in the longer-term by 2050 [10] for the high and early export (NZEE) scenario. Table 24 provides a summary of the ammonia (NH3) and Fischer Tropsch (FT) values together with the corresponding amount of equivalent hydrogen for the NZEE scenario. As can be seen from the table, we are focussing on ammonia and Fischer-Tropsch (FT) fuel exports in this study. In the future, other options such as methanol, dimethylether (DME), DRI or sponge iron (also potentially as a carrier) should also be analysed.

As South Africa already has large FT synthesis capacities with Sasol Secunda, which produces 7.5 to 7.7 Mt of Fischer-Tropsch crude annually [22], the study is focussing on FT export in the long term. This is slightly optimistic regarding the availability of green CO_2 feedstock and the possibility of transforming Sasol‘s large park. A key challenge faced by Sasol is that the European Renewable Directive (RED) II and the Delegated Acts (DA) on renewable fuels of non-biological origins (RFNBO’s), which includes Fischer-Tropsch fuels, does not allow for the flexible allocation of green electrons toward specific products. This poses a challenge for transitioning large scale Fischer-Tropsch facilities which aim to export their products into the EU market. Furthermore, the focus on FT after 2030 is supported by stakeholder feedback received during the during the initial workshop which emphasised that ammonia will also be needed for local use after 2030 (see appendix 8.3).

Table 24: Export quantities for NZEE. For CP and NZ, the export values are a pessimistic 10% of the values shown.

Export	Unit	2030	2040	2050
NH3 (NZEE)	TWh	21.3	32.0	47.9
FT (NZEE)	TWh	1.4	45.0	103.2
H_2 (NZEE)	TWh (Mt)	28 (0.83)	99 (3)	193 (5.8)

In the CP and NZ scenarios, a cautious outlook regarding the implementation of announced projects is assumed. These scenarios consider various challenges that may impede the ramp-up at both the national level and globally, assuming global demand does not grow as rapidly as current strategies predict. Consequently, only 10% of the export volumes indicated in Table 24 are considered in these two scenarios. The export prices are the same for all scenarios and explained in section 2.4.1.

3.4 Wind, PV and Grid Expansion

As detailed in section 2.7.3, two types of grid restrictions are taken into account via limitations in the model and in the scenarios. Firstly, the grid connection capability (GCC) and, secondly, the power transmission capacity of the cross-regional transmission grid.

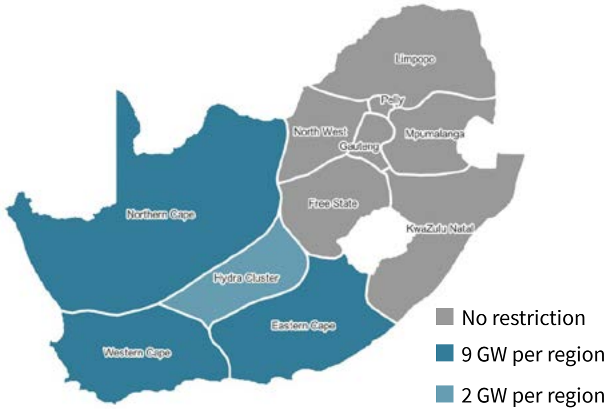


Figure 46: Renewable (Wind or solar PV) generation connection capacity limits for 2030 based on the TDP. Own illustration based on [25].

Regional limits for wind and solar PV expansion

The GCCA's of 2024 and 2025 show that the western regions currently face connection bottlenecks. Therefore, wind and PV expansions are limited for 2030 in the western regions according to the TDP planned grid and generation capacity expansion to account for real-world connection constraints in the time horizon up to 2030. The provincial cumulative allocation of generation by technology in these regions was used to estimate the probable generation connection capacity in 2030 by subtracting the existing capacity per province from the projected cumulative generation by 2032. The emerging connection constraints that were implemented are summarised in Figure 46. Accordingly, 9 GW can be added by 2030 in the Northern Cape, Western Cape and Eastern Cape respectively. In the region labelled Hydra Cluster, only 2 GW.

Inter-regional transmission line expansion limit

Regarding the expansion of the transmission grid in the longer-term, a limit of 10% growth of the current existing inter-regional transmission capacities (see section 2.7.4) up to 2050 was applied for all three scenarios. The impact of this factor on the system costs is analysed with an extra sensitivity calculation (see section 3.4).

3.5 Sectoral Final Energy Consumptions

According to the JET-IP, the electricity sector accounts for 43% of total emissions, followed by liquid fuels production, mainly coal-to-liquids (CTL), at 12%, and road transport at 11%, with road transport making up 96% of overall transport emissions [20]. Almost all GHG emissions in the liquid fuels manufacturing sector are produced by the production of liquid fuels from coal at Sasol's Secund plant. In 2019, Sasol announced publicly that GHG emissions from its South African operations would be reduced by 10% from their 2017 baseline, and a year later, announced that GHG emissions would be reduced by 30%. This outcome is expected to result from a combination of replacing a portion of onsite coal-fired utilities with renewable energy sources and enhancing the overall process efficiency, where improvements could involve increased utilisation of natural gas or green hydrogen [106].

Key policy-relevant characteristics, measures, sectoral GHG profiles, and mitigation options were modelled through 65 separate cases within a timeframe to 2030 and beyond for the JET-IP [20]. These cases were used to inform and shape the scenario definition of demand projections for the current study. Two demand scenarios were selected to adapt our narrative. These included a delayed transition and an ambitious transition. The ambitious transition represents successful implementation of energy efficiency measures, modal shifts, fulfilment of the GTS, uptake of new electric vehicles (with price parity assumed in 2027) and adoption of new industrial processes (e.g. DRI). The delayed transition assumes price parity of electric vehicles post 2030, low implementation of energy efficiency measures and a lag in the adoption of new industrial technologies and processes.

The energy efficiency targets from the draft post-2015 National Energy Efficiency Strategy and initiatives from the Green Transport Strategy (GTS) were implemented in the ambitious demand scenarios (extracted from the JET-IP), which are detailed in the following sections. Please refer to the Annexure B (Electricity Sector Modelling Assumptions, Technical Analysis, and Eskom JET Project Pipeline [20]) for further details on the methodology used.

3.5.0 Green Transport Strategy (GTS)

The GTS, fully implemented for the ambitious sectoral demand path, was implemented conservatively in a series of demand-side strategies [20, 31] which are highlighted below:

- By 2030, the rail share of corridor freight transport will be 30%, reaching 50% by 2050.
- A 20% relative shift from passenger to public transport will be achieved by 2030.
- A minimum of 10% of the vehicle population will comprise EVs and hybrids by 2030, reaching 40% by 2050.
- Minibus conversion to bi-fuel (compressed natural gas (CNG) / petrol) vehicles where 10% of the minibus taxi fleet will be converted to be bifuelled by 2030, reaching 40% by 2050 vehicles by 2030.
- Metrobus to gas shift with 10% of the municipal bus fleet being converted to gas by 2030, reaching 30% by 2050.
- Biofuels – 2% blending with petrol and 5% blending with diesel by 2030 was included in the planned policies scenario.

3.5.1 Draft Post-2015 National Energy Efficiency Strategy (NEES)

Sectoral targets proposed for 2030 in the NEES were included for the ambitious path [20, 32] as follows:

- Residential: 30% improvement in the efficiency of household energy appliances by 2030, and a 20% improvement in the energy efficiency of residential buildings is achieved by 2030.
- Commercial: 37% reduction in energy intensity in commercial buildings, including government buildings, by 2030.
- Mining: 40 petajoules (PJ) savings identified by the NEES translates into a 4% energy savings by 2030.
- Manufacturing: 35% improvement in energy efficiency in all applications other than furnaces and kilns, which improve by 5% by 2030.

3.5.2 Final Demand Projections

The emerging ambitious sectoral demand projections for the transport, industry and commercial, residential and agricultural sectors are presented in Figure 47 -Figure 51. Demand projections for the delayed transition can be found in Appendix 7.2.0. The collection of this input data results from collaborative efforts with UCT utilising SATIMGE, which combines SATIM (bottom-up full-sector energy systems model of South Africa) and eSAGE (a dynamic, recursive, economy-wide, multi-sector computable general equilibrium (CGE) model [20] together with international and domestic shipping demands obtained from the UNDP [89] and potential ammonia production based on local usage and potential export values [107].

The combined emerging ambitious demand trajectories up to 2050 were used as inputs into the PyPSA-RSA-Sec model for the NZ and NZEE scenarios. The sector-wide demand projection is illustrated in Figure 52.

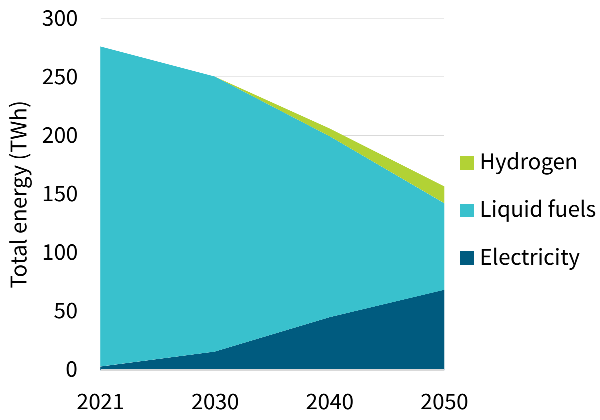


Figure 47: Ambitious transition of the transport sector. Own illustration based on [20].

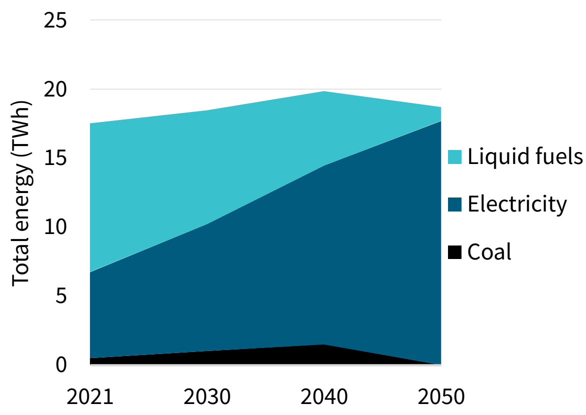


Figure 48: Ambitious transition of the agricultural sector [3].

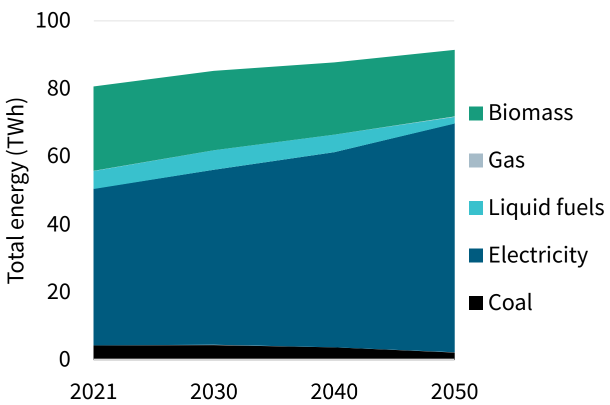


Figure 49: Ambitious transition of the residential sector. Own illustration based on [20].

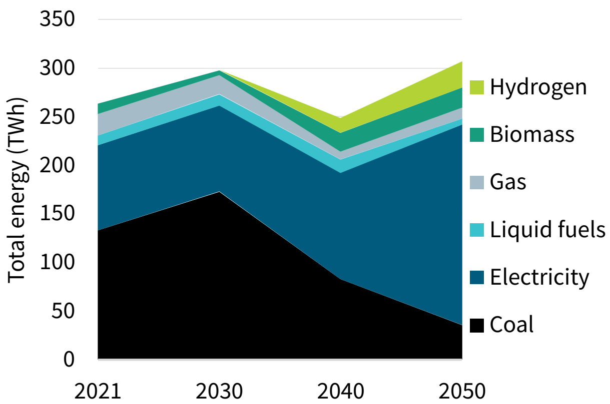


Figure 50: Ambitious transition of the industrial sector. Own illustration based on [20].

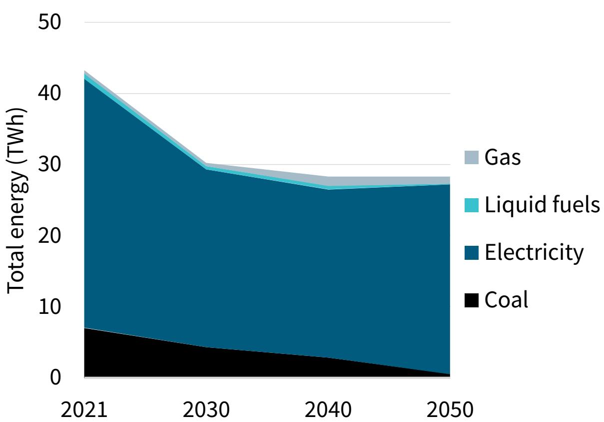


Figure 51: Ambitious transition of the commercial sector. Own illustration based on [20].

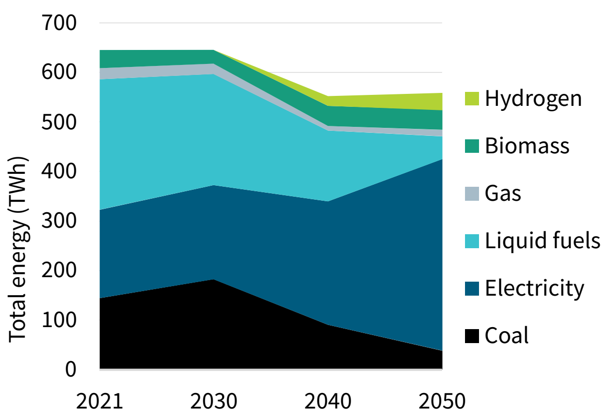


Figure 52: Sector-wide ambitious demand projection. Own illustration based on [20].

3.5.3 Energy Demands by End-Use

The projected final energy demands by end-use are shown in Figure 53 to Figure 59 for the transport, industry, commercial, residential and agricultural sectors based on the JET-IP ambitious demand projections combined with international and domestic shipping demands obtained from the UNDP [89] together with and potential ammonia production based on local usage and potential export values [107]. End-use energy demands for the moderate/ delayed transition scenarios can be found in Appendix 7.2.0.

By 2050, it is anticipated that a significant portion of transport will be electrified, driven by industry trends, international market signals phasing out internal combustion engines (ICEs), and the need for decarbonisation. Although hydrogen-fuelled vehicles might also play a role, their future is less certain due to the technology's early development stage. Hydrogen vehicles would use combustion engines, which are less energy-efficient compared to electric vehicles with electric motors [88]. Historical values for international marine bunkering and domestic navigation were used to estimate shipping demands [89].

Fuel and technology switches, such as the switch from coal-based blast furnaces to hydrogen-based DRI for steel production, are considered in the SATIM model for different sectoral industries as discussed in section 2.8. However, these would require substantial investments and are likely limited to a few industries like steel and chemicals. Due to rising electricity prices and load shedding, industries have typically prioritised energy efficiency to reduce costs. This trend, along with increased adoption of self-generated power through IPPs and solar PV systems, is expected to continue [33, 88]. It should be noted that the ammonia plant demand projections deviate from the JET-IP scenarios. In the ambitious demand scenario, imported nitro-fertiliser from Southern Africa is projected to be gradually replaced by domestic green ammonia and fertiliser production. Fertiliser production is estimated to increase to 3 Mt of nitro-fertiliser. Conversely, for the delayed transition scenario, the 2021 levels were utilised as the projected demand for 2030, 2040, and 2050. This assumes limited incentives for switching to green hydrogen in this conservative scenario. In the steel industry, the incentive for transition would stem from export requirements, particularly in countries enforcing the Carbon Border Adjustment Mechanism (CBAM). For ammonia used locally, the absence of regulatory drivers could potentially reduce motivation for a shift to green hydrogen-based production.

Figure 55 and Figure 56 provide a breakdown of the iron and steel sub-sector energy demands per technology and fuel type for 2030 and 2050 respectively. The emerging application of hydrogen in the DRI route is highlighted in Figure 56.

It was assumed in the JET-IP that energy services in new buildings could be met more efficiently with newer technologies, adherence to green building codes (such as SANS10400 XA2), implementation of Minimum Energy Performance Standards (MEPS) and the introduction of energy endorsement labels for energy-efficient appliances [48, 86].

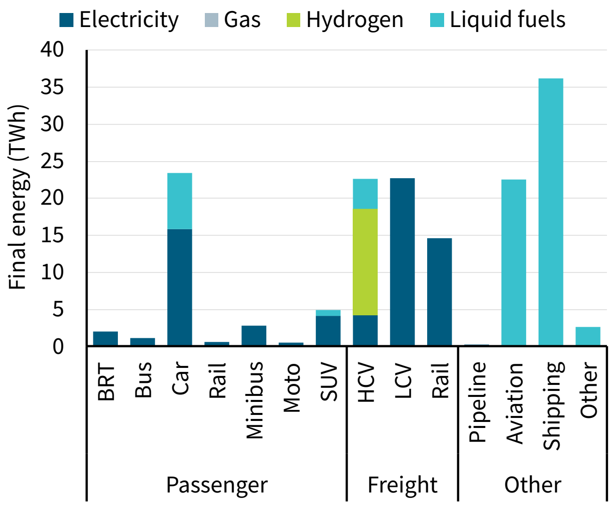


Figure 53: Transport sector energy demand per technology and fuel type for 2050 ambitious scenario. Own illustration based on [20].

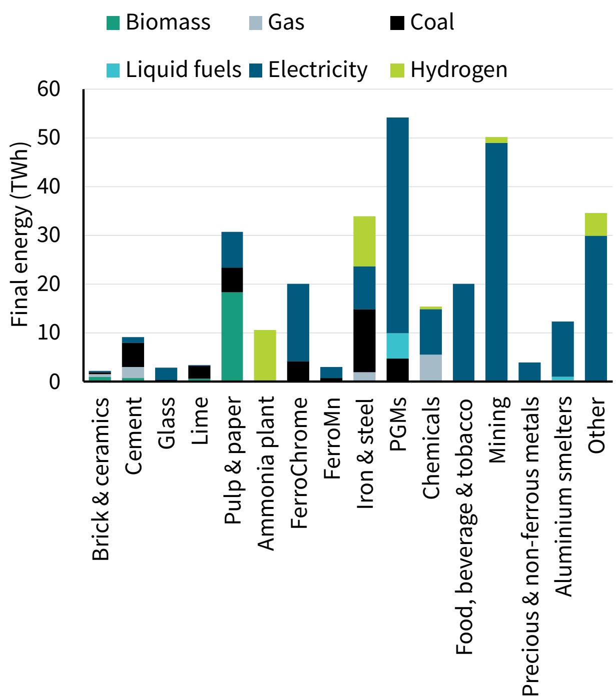
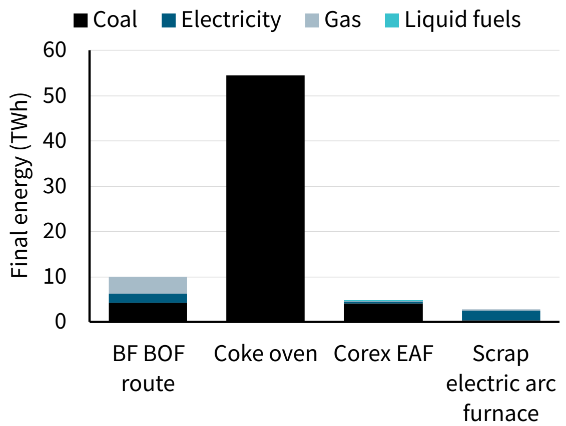


Figure 54: Industry sector energy demand per industrial branch and fuel type for 2050 ambitious scenario without extra export demands. Own illustration based on [20].



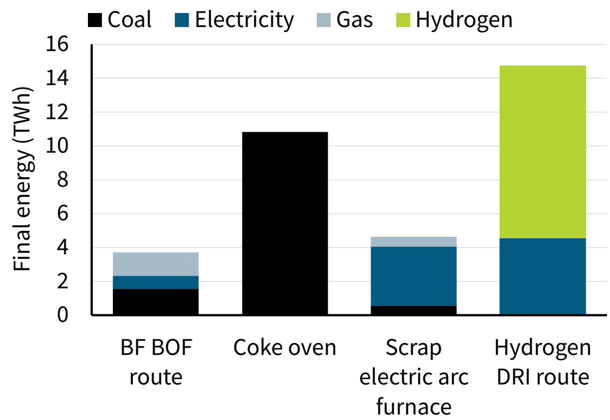


Figure 55 and Figure 56 provide a breakdown of the iron and steel sub-sector energy demands per technology and fuel type for 2030 and 2050 respectively. The emerging application of hydrogen in the DRI route is highlighted in Figure 56.

Figure 56: Iron and steel sub-sector energy demands per technology and fuel type for 2050 ambitious scenario. Own illustration based on [20].

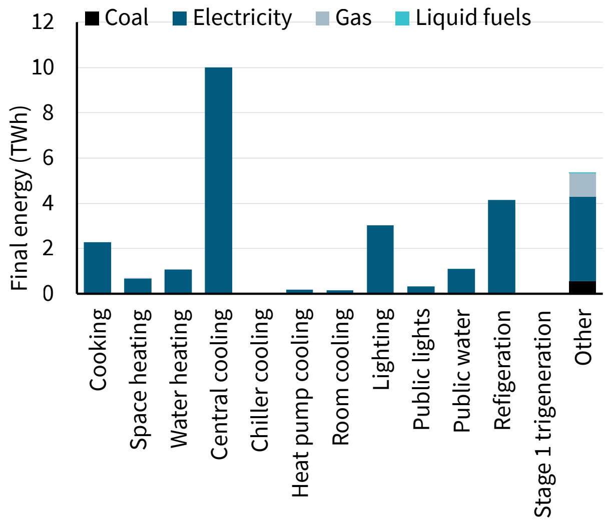


Figure 57: Commercial sector energy demand per technology and fuel type for 2050 ambitious scenario. Own illustration based on [20].

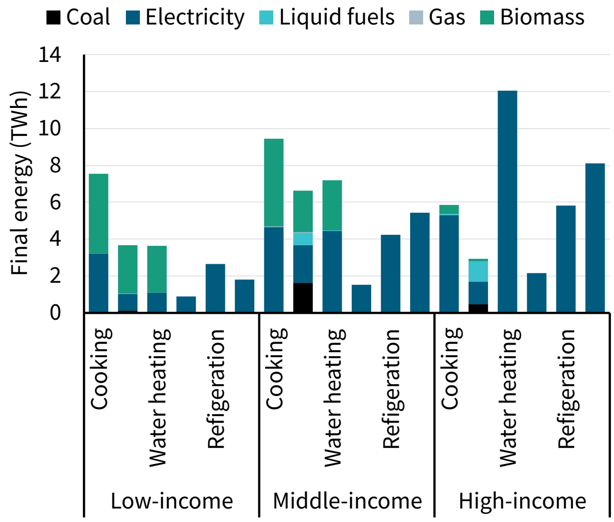


Figure 58: Residential sector energy demand per technology and fuel type for 2050 ambitious scenario. Own illustration based on [20].

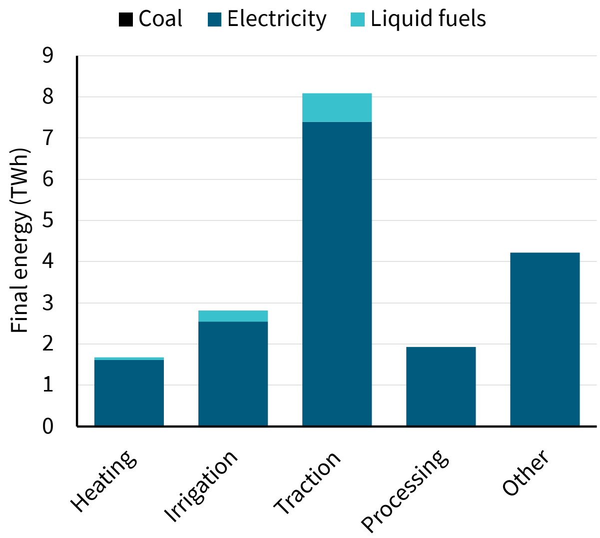


Figure 59: Agricultural sector energy demand per technology and fuel type for 2050 ambitious scenario. Own illustration based on [20].

4 Results of the Modelled Pathways

The key metrics for the future energy system are the production and consumption (market balances) per energy carrier and feedstock (intermediate) markets, the resulting CO_2 emissions, the installed electricity, hydrogen, and storage capacities, the system costs, as well as further impacts such as water consumption. These metrics are presented in the following sections for the main scenarios, and for the additional sensitivity model runs which test single parameters. No- or least-regret expansion targets (with lower thresholds) and insights from the comparison of the different scenarios will also be presented.

4.1 Analysis of Main Scenarios

4.1.0 Electricity Demands

The analysis begins with the development of net electricity consumption and electricity generation (see section 4.1.1) in the planning years 2030, 2040 and 2050 for each scenario. The electricity loads result from exogenous specifications for the electrification of the sectors, assumptions about economic growth, efficiency measures and the endogenous dimensioning of the H_2-relevant electricity consumers such as the H_2 Electrolysis. Figure 60 reveals that **electricity demand increases by a factor of 2.6 to 4.3 across all scenarios compared to 2022** (233TWh) [5]. In part, this increase results from the direct electrification of end consumption in industry, commerce, residential and transport. The electricity demand of the domestic **industry sector doubles** from 99 TWh (NZ, NZEE) and 112 TWh (CP) in the year 2030 to 206 TWh (NZ, NZEE) and 219 TWh (CP) in the year 2050, reflecting the increasing reliance on electrification to meet industry demands. The electricity requirements in NZ and NZEE are slightly lower because additional efficiency measures are applied despite the same economic growth. Electricity demand in the **residential sector** grows steadily across all scenarios from 52 TWh in 2030 to 68 TWh **(+30%)** by 2050, mirroring the ongoing electrification in households.

Electrification in the transport sector, particularly in electric vehicles and rail, leads to notable demand increases. Both NZ and NZEE scenarios show earlier and higher adoption of battery electric vehicles compared to the CP scenario. In 2050, the consumption of electric vehicles is slightly higher compared to NZ, because NZ is more efficient due to a higher share of public transport**. In NZ and NZEE, electricity demand from electric vehicles grows faster and reaches 37 TWh, compared to 26 TWh in the CP scenario in 2040.** This earlier adoption accelerates decarbonization in the transport sector. Similarly, **rail transport demand grows from 6.7 TWh to 15 TWh in NZ and NZEE**. In the CP scenario, rail transport sees slower growth, rising from 4.3 TWh in 2030 to 7.6 TWh in 2050. This reflects slower investment in rail electrification infrastructure. The delay or slower electrification in rail could be attributed to challenges like infrastructure development, theft of rail components (e.g., cables), and other logistical issues, which were highlighted as key barriers in the stakeholder workshops.

With regard to net electricity consumption without the demands of the hydrogen economy and battery charging, the demand projections show considerable potential for energy efficiency measures. Net electricity consumption without H_2 electrolysis and battery charging is around 5% lower in NZ and NZEE than in CP (less energy efficiency measures, see chapter 3.1).

The **largest potential driver of electricity consumption in the scenarios is the indirect electrification (PtX)** of consumption in South Africa and globally, i.e. for the export of PtX products. In both CP and NZ, 10% of the volumes of the NZEE scenario are exported. NZEE is constrained by the same CO_2 limit as NZ but achieves significantly higher export volumes (see chapter 3.3). Electricity consumption for H_2 Electrolysis in CP and NZ are 4.3 TWh and 5.1 TWh respectively (+19% to CP) by 2030, 48 and 50 TWh by 2040, 95 TWh and 166 TWh (+75% to CP) by 2050. While these additional electricity demand volumes are already very significant, the NZEE scenario is even more ambitious. The figures amount to 44 TWh in 2030 and rise to 183 TWh by 2040, which marks a significant difference of +366 % compared to CP and NZ in 2040. **In 2050, the consumption of H_2 electrolysis at 406 TWh is 4.3 times as high in NZEE as in CP. Accordingly, the share of electricity consumption for H_2 electrolysis is 50% of the net electricity consumption of 817 TWh** (without battery). The following sections detail in which markets PtX products are needed and explain why the consumption is higher in NZ in 2040 (see Liquid fuel and methane balance or section 4.3).

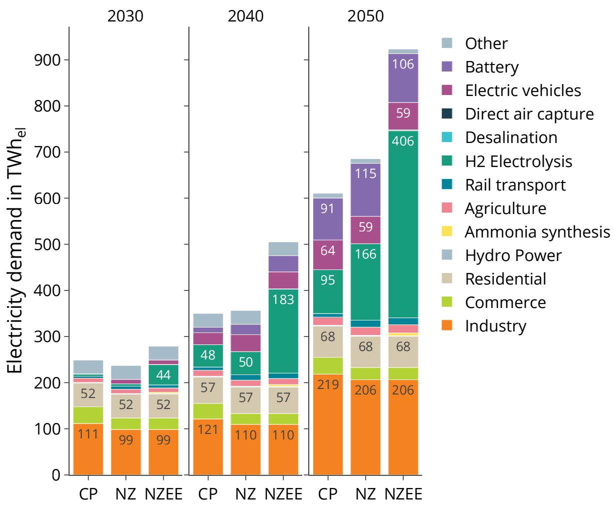


Figure 60: Electricity demand, battery storage charging, self-consumption and exports (other) for CP, NZ, and NZEE.

Key conclusions

- Electricity demand increases by a factor of 2.6 to 4.3 across all scenarios compared to 2022.
- The increase in electricity consumption is due to direct and indirect (via PtX) electrification for various end uses. The electricity load of today's industry sectors is anticipated to double by 2050. New electric vehicles will lead to an electricity consumption of 59 to 64 TWh by 2050. Cooling, heating, cooking and other applications in the residential sector will continue to be electrified (+30% from 2030 to 2050).
- The hydrogen economy consumes 95 to 406 TWh of electricity in the three main scenarios by 2050. In 2050, the consumption of H_2 electrolysis at 406 TWh is 4.3 times as high as in CP. The share of electricity consumption of H_2 electrolysis is 50% of the net electricity consumption of 817 TWh (without battery) in the ambitious net-zero and export scenario NZEE.

4.1.1 Electricity Supply

In the development of coal and nuclear electricity supply across the scenarios, the data shows a significant reduction in coal reliance over the projected periods, while nuclear energy remains relatively stable with no additional nuclear deployment foreseen in any scenario. Nuclear power is not expanded in any scenario because of long construction times and high capital expenses compared to renewables. In the **Current Policy** (CP) scenario, coal-fired power plants are phased out as planned today by ESKOM, where a low CO_2-price is assumed, and the scenario doesn't apply a system-wide CO_2 limitation. As a result, **coal is used less than today**, but is still a major source of electricity in **2030 at 129 TWh (72% of the 177 TWh in 2022)** [5]. After 2030 the coal-based production declines sharply to 40.4 TWh by 2040, and further drops to just 11 TWh by 2050. The **Resilient Net-Zero** (NZ) scenario sees a steeper decline, with coal generation starting at **93 TWh in 2030 (27% lower than CP)**, dropping significantly to 7 TWh by 2040 (83% lower than CP), and phase-out before 2050. In the **Net-Zero + High and Early Exports** (NZEE) scenario, coal supply follows a similar trend, beginning at

100 TWh in 2030 (24% lower than CP), and decreasing to 5.5 TWh in 2040 (86% lower than CP). The existing **nuclear power** plant maintains a constant **contribution of around 16 TWh** in all scenarios until they are taken off the grid before 2050. This reflects nuclear's role as a steady, albeit non-expanding, contributor to the energy mix amid the broader transition towards renewable energy sources.

The contribution of gas turbines is the highest in the NZ scenario, contributing more than in the CP scenario, with 14.4 TWh anticipated by 2050. This is complemented with a substantial growth in battery storage output, reaching 15 TWh in 2040 and expanding to 64 TWh by 2050. Together, gas turbines and battery storage are anticipated to play a critical role in ensuring grid stability amidst the high integration of renewable energy sources.

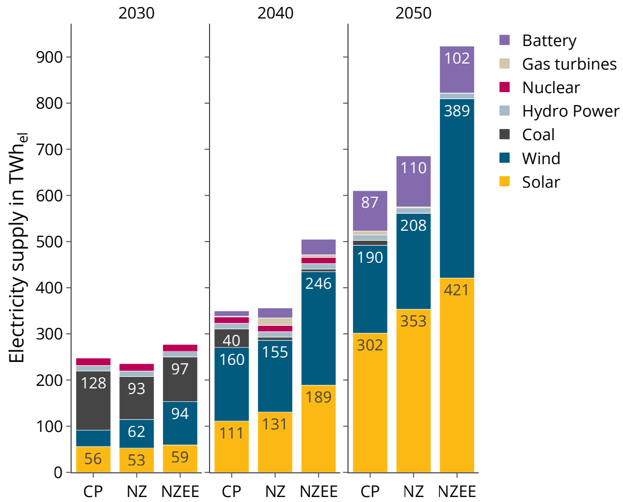


Figure 61: Electricity supply, and battery storage discharging for CP, NZ, and NZEE.

When examining the volumes and shares of wind and solar generation across the scenarios, it is evident that renewables are **key technologies for meeting South Africa's growing electricity demands in least-cost pathway scenarios by 2050**. The optimisation model recommends a generation mix of solar and wind in a ratio of around 2:3 to 2.5:3 (solar to wind) in NZ and NZEE before 2050, shifting to 3:2 in 2050. The model selects this energy mix based on CAPEX considerations and the need to minimise curtailment. This configuration effectively balances the fluctuations of variable renewable generation across time and space. The higher solar shares in the NZ and NZEE scenarios by 2050 highlight that solar is the most cost-effective electricity source and integrates well with hydrogen electrolysis and the smart charging of electric vehicles as their adoption scales up. Prior to 2050, efforts should focus on expanding wind and solar capacities in line with the specified shares. Achieving this will require the implementation of the TDP for the NZ scenario and further strengthening of substations for the NZEE scenario.

In the CP scenario, solar power generation is at 56 TWh in 2030, significantly increasing to 111 TWh by 2040 (+99% from 2030), reaching 302 TWh by 2050. Wind power similarly grows, starting at 36 TWh in 2030, jumping to 160 TWh by 2040 (+348% from 2030), and peaking at 190 TWh by 2050. **This growth in renewables is driven not only by the replacement of coal-fired power plants, but also by the need to meet growing electricity demand. These results illustrate the cost-competitiveness of RE, highlighting the expansion of renewables as a no-regret option even under current policy conditions.** It is important to note that the CP scenario assumes the successful implementation of the network infrastructure expansion planned in the TDP 2022, which is essential to support this transition.

The NZ scenario, in comparison, requires solar power generation of 53 TWh in 2030, which grows to 131 TWh by 2040, marking an increase of 148% over this decade. By 2050, solar generation further expands to 353 TWh, a 171% increase from 2040. Wind power in this scenario rises to 62 TWh in 2030, increasing to 155 TWh by 2040 (+151%), and reaching 208 TWh by 2050, reflecting a 34% increase from the previous decade. **Combined, wind and solar power supply totals** 114.5 TWh in 2030, 286.0 TWh in 2040, and **561.2 TWh in 2050**, which is **13% higher than the CP scenario in 2030, 6% higher in 2040, and 22% higher in 2050**. These results illustrate the impact of an earlier coal phase-out and a CO_2 limit. These measures result in significantly higher adoption rates of wind power generation in 2030 and 2040, and higher RES generation levels in total being required for both technologies in 2050 for meeting stringent carbon reduction targets.

In the NZEE scenario, solar power contributes 59 TWh in 2030, substantially increasing to 189 TWh by 2040, representing an increase of 218%. By 2050, solar reaches 421 TWh, reflecting a further 123% growth from 2040. Wind power exhibits even stronger growth, from 94 TWh in 2030 and expanding to 246 TWh by 2040 (+162%). By 2050, wind generation surges to 389 TWh, representing a 58% increase from 2040 levels. The combined total for wind and solar power supply in NZEE is 153 TWh in 2030, 435 TWh in 2040, and 810 TWh in 2050. **The difference of 44% to 65% more**

renewable energy in total **by 2050** compared to NZ (561 TWh) and CP (492 TWh) **underscores the importance of considering different hydrogen production levels in energy system planning**. Alignment between South Africa's green hydrogen strategies and roadmaps and the country's integrated resource and energy planning is required to assess feasibility, allocate renewable energy expansion, and facilitate infrastructure development.

In summary, the comparison of scenario outcomes shows that while CP also sees strong growth in renewables in 2040 and 2050 due to demand growth coupled with the retirement of old plants, the NZ and especially the NZEE scenarios significantly outperform it, emphasising their focus on earlier coal phase-out, emission reductions and ambitious PtX exports (in NZEE). Compared to the contribution of wind and solar power of 16.2 TWh in total in 2022 [5], it becomes clear that enormous expansion efforts are required to achieve these expansions. The electricity capacity expansions are analysed and illustrated in detail in the following chapter.

Key conclusions

- Under the scenario assumptions, coal is used less than today, but is still a major source of electricity in 2030 at 93 (NZ) to 129 TWh (CP), which corresponds to 53 % to 72% of the 177 TWh coal-based electricity of 2022 [5]. After 2030 the production declines sharply to 40.4 TWh by 2040 and to 0 to 10 TWh by 2050, due to plant retirements. Existing nuclear power maintains a constant contribution of around 16 TWh in all scenarios until retirement before 2050. This reflects nuclear's role as a steady, albeit non-expanding, contributor to the energy mix.
- In all scenarios analysed, wind and solar energy confirm their status as cornerstones of the supply of South Africa's growing future electricity demand. By 2050, solar electricity generation is optimised to increase significantly from at least 53 TWh in 2030 to between 302 TWh and 421 TWh by 2050, while wind energy expands its contribution to a range of 36 TWh to 94 TWh by 2030 to a range of 190 TWh to 389 TWh by 2050, depending on the scenario.
- The drive to capitalise on hydrogen export opportunities has a significant impact on the scale of renewable energy development required. This is evidenced by the marked difference between a low hydrogen export scenario, which results in 561 TWh of wind and solar electricity generation, and a high export scenario, where this figure rises to 810 TWh by 2050. Such variations highlight the importance of considering different levels of hydrogen production in a holistic approach to energy system planning.

4.1.2 Electricity Capacities

The capacity expansions required to generate the electrons, provide the flexibility needed, fulfil the policy constraints and reach the hydrogen targets of each of the main scenarios are analysed in the following sections. The analysis highlights the development of wind and solar capacity and new-build dispatchable capacities (gas turbines + battery). Furthermore, the expansion figures in this chapter are compared with the figures from existing studies for 2030 to provide context.

Wind and solar PV capacities

As analysed in the previous chapter, solar and wind are the pillars of the electricity system optimised under political and economic boundary conditions. In the CP scenario, the expansion is impacted by a moderate coal phase-out with 35 GW still online by 2030 compared to 25 GW in NZ and NZEE and 21 GW available in 2040 compared to a phase-out by 2040 in the other two scenarios. Furthermore, CP as well as NZ are limited by regional grid connection limitations in the western regions. CP is not restricted by a global carbon emission limitation. **Even in the CP scenario the installed capacity for solar and wind power shows significant growth over the analysed period.** Solar capacity is optimised to rise to **30 GW in 2030** (+400% from 2023), to 65 GW by 2040 (+117%), and further expand to **189 GW by 2050** (+191% from 2040). Wind capacity also sees a substantial increase, starting at 11 GW in 2030 (+324%), climbing to 58 GW by 2040 (+427%), before reaching 74 GW by 2050 (+28% from 2040). This means that in the CP scenario, coal-fired power plants, which are approaching the end of their service life by 2050, will be replaced by solar and wind energy with cost-optimised expansion (albeit with regional restrictions). The sharp **increase** from **2030 to 2040, with growth of +427%** in this scenario, **could be a challenge compared to a potentially more even growth towards 2050.**

In the **NZ scenario**, the development of wind capacity is marked by a more ambitious upward trend. **Wind capacity** follows a robust growth path, starting at **21 GW in 2030**, surging to 57 GW by 2040 (+171%), and reaching **81 GW by 2050** (+42% from 2040). **Solar capacity** begins at 29 GW in 2030 and accelerates to 79 GW by 2040 (+172%). By **2050**, it further increases to **223 GW** (+182% from 2040). Combined, **the total wind and solar capacity in 2030 (50 GW) is 32% higher than CP's 41 GW for that year, and by 2050, the total of 304 GW is 31% higher than CP's 263 GW.** By 2050 both NZ and CP show substantial growth in wind and solar capacity and reach 241 to 245 GW total. **However, growth in the NZ scenario is more consistent and balanced.**

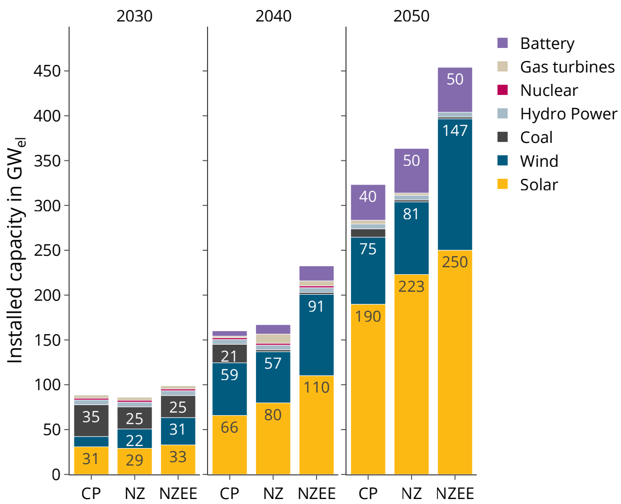


Figure 62: Installed capacities for electricity supply in CP, NZ and NZEE.

In the **NZEE** scenario, wind and solar (in 2040 and 2050) capacity growth is even more pronounced. In contrast to NZ, the NZEE scenario assumes that PtX projects in regions with reduced grid connectivity will co-finance distribution grid components for the connection of RES and H_2 electrolysis and connect the systems to the transmission grid to a limited extent. This facilitates the assessment of the great wind resources in the Northern Cape. Further findings on spatial aspects can be found in the subchapter on spatial aspects.

In NZEE, wind capacity sees an aggressive expansion, with 30 GW in 2030 and jumping to 90 GW by 2040 (+200%), then growing further to 146 GW by 2050 (+62% from 2040). Solar capacity starts at 32 GW in 2030 and rapidly rises to 110 GW by 2040 (+244%), ultimately reaching 250 GW by 2050 (+127% from 2040). **The combined solar and wind capacity in 2030 (62 GW) is 51% higher than CP's 41 GW and 24% higher than NZ's 50 GW for the same year. By 2050, the total capacity in NZEE reaches 396 GW, which is 50% higher than CP's 263 GW and 30% higher than NZ's 304 GW.** This significant difference in renewable capacity is due to the fact that the NZEE scenario focuses not only on domestic defossilisation, but also on scaling up renewables to meet high export targets for positioning South Africa as a key player in the global PtX market (demand from export volumes are shown in the following chapters).

Gas turbines and battery capacities

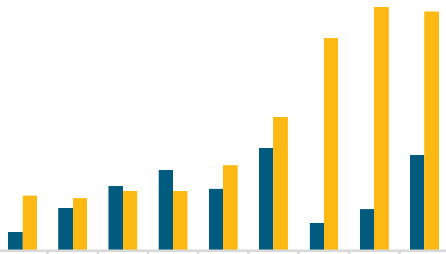
The need for gas turbines and batteries, in particular, evolves notably across the scenarios by 2040 and beyond as part of the energy system's transition towards renewable energy integration. Gas turbines and batteries are both primarily used as supplementary or backup power sources, reflecting the role they play in stabilizing the grid when solar and wind experience intermittency. Across all scenarios, investments in stationary batteries for the national system under consideration do not start until after 2030. In the real world and at the local level, however, stationary batteries may still be necessary as a supplement and to stabilise local grids. But not on the scale of several GW.

In the **CP scenario**, the **gas turbine** capacity is not significantly expanded and amounts to 4 GW. The capacity for **batteries** rises to 5 GW by 2040 and shows significant growth to **40 GW by 2050**. In the **NZ** scenario, **gas turbines increase to 10 GW by 2040.** This indicates the need for more gas turbine capacity requirements in NZ compared to CP (+6GW) to complement the renewables. **Battery capacity** increases to 10 GW by 2040, and reaches **49 GW by 2050**, showing an even greater dependence on storage solutions for balancing the grid as fossil fuel contributions decline. The Net-Zero + High and Early Exports (NZEE) scenario reflects the most aggressive shift towards advanced storage solutions, with battery capacity in NZEE increasing to 16 GW by 2040, and further expanding to 50 GW by 2050 (same level as needed in NZ). But gas turbines only increase to 5 GW by 2040. **The same level of battery capacity**

and lower levels of gas turbines indicate the synergies of a larger renewable generation capacity (30% higher than in NZ) and the **H_2 production, which seems to not add to the need for supply flexibility** (see section 4.1.8 for further insights on the operation of H_2 Electrolysis). Across all scenarios, the trend illustrates a strategic pivot towards battery storage to ensure energy reliability and mitigate the variability of renewable energy by and beyond 2040, while gas turbines serve as a transitional tool that fades as storage technology scales up and matures. **Battery capacity requirements across all scenarios range between 40 to 50 GW by 2050. Gas turbines' capacities range between 5 to 10 GW by 2040.** It should be noted here that the model used demand-side-management for charging electric vehicles but not for Vehicle-to-Grid (V2G). Activating V2G could reduce the need for stationary batteries.

Comparisons and Context for Wind and Solar

All scenarios show that a massive expansion of electricity generation capacity is required to accommodate the projected increase in demand cost-efficiently. At a minimum in 2050, the total capacities of wind and solar are around 6.7 times higher than the installed coal power capacity of 2023 (39 GW) [12] and at maximum 10 times higher.



	CP	NZ	NZEE	CP	NZ	NZEE	CP	NZ	NZEE
	2023-2030			2030-2040			2040-2050		
Wind (GW/yr)	1.1	2.5	3.8	4.7	3.6	6.0	1.6	2.4	5.6
Solar (GW/yr)	3.2	3.1	3.5	3.5	5.0	7.8	12.4	14.4	14.0

Figure 63: Average annual wind and solar build rates required for the periods 2023-2030, 2030-2040 and 2040-2050 for each of the scenarios.

To achieve the optimal capacity targets by 2050 in the scenarios focussing on domestic demands (CP, NZ), the average annual build rate for wind ranges from 1.1-3.6 GW/year among periods and from 3.1-14.4 GW/year for solar PV. The expansion of solar PV has to increase significantly for the period 2040 to 2050. The highest wind power build rates are observed for the period 2030-2040. If South Africa aims to capitalize on high export opportunities, the required per anno expansion for wind increases to 3.8 (+52% to NZ), 6.0 (+67% to NZ), and 5.6 GW (+133%). The annual solar build rate is significantly higher (7.8GW/year, +56%) from 2030-2040 but similar to NZ otherwise.

This implies high growth rates compared to South Africa's past highest renewable energy expansion achieved per year, which reached only 0.6 GW for onshore wind [108] and 2.3 GW for solar PV [12]. However, the +2.3 GW of embedded PV capacity already represents a major growth spurt compared to previous years. Furthermore, the South African Renewable Energy Masterplan expects a rollout of RES of 3 to 5 GW per annum by 2030. The survey (done in Mentimeter) results of the first stakeholder workshop of this project revealed that the PV expansion (private + utility-scale) lay between 7.4 to 10.2 GW/a from 2030 to 2050, whereas wind is between 3.9 and 6 GW/a for the same periods. Also, it is expected that projects already awarded in auctions (around 9.7GW) or planned will lead to a significant increase in wind and solar capacities in the coming years. At the Windaba 2024 conference, South African Wind Energy Association (SAWEA) CEO Niveshen Govender noted that 53 GW of wind are already in the development pipeline [109].

Govender states that the main issues for boosting renewables are grid constraints and structural problems. Lastly, the global perspective shows that with the right enablers in place, a rapid and large-scale expansion of renewable energy infrastructure is possible. In 2023, renewable capacities grew by 50%, with China alone adding 310 GW of new capacity [110].

For further contextualisation of the mid-term impact of the scenarios, the wind and solar expansion figures for 2030 are compared with those of the studies presented in section 1.1.

Table 25: Percentual difference of CP and NZEE-2030 capacities vs. JET-IP, TDP2023, IRP2023 and a Meridian NZ. Sources: [20, 25, 27, 28].

Scenario result	JET-IP	TDP2023	IRP2023 -Draft	Meridian NZ, 9Gt
Wind (CP)	-57%	-58%	39%	-29%
Solar (CP)	17%	64%	74%	-3%
Wind (NZEE)	17%	14%	279%	95%
Solar (NZEE)	25%	75%	86%	3%

The wind power capacity in the CP scenario is lower than those of the selected decarbonisation scenarios of existing studies, such as JET-IP, TDP2023, and Meridian, with negative percentage differences ranging from -29% to -58%. However, the expansion in CP is even 38% higher compared to the IRP2023 projection. This means that the IRP2023 draft expects even greater problems with the expansion of wind power and is more likely to build gas turbines instead. Solar PV is used significantly more or equally compared to all other scenarios, with positive differences compared to TDP2023 (+64%) or IRP2023 (+74%) and only +17% compared to the more ambitious JET-IP. Solar expansion is only down by -3% compared to the Meridian scenario optimisation. Overall, the capacities are lower than the Meridian NZ scenario, corroborating that the CP pathway is not in line with a NZ trajectory.

In contrast, the export scenario (NZEE) displays a much more aggressive expansion, particularly in wind, with significant positive differences against all studies. The most pronounced gap is with IRP2023 (+279%) and Meridian (+95%) for wind capacity. Similarly, for solar PV, NZEE surpasses the JET-IP, TDP2023, and IRP2023 projections with differences of +25%, +75%, and +86%, respectively, but closely aligns with Meridian-NZ. **This comparison highlights the significance of NZEE and this PtX-focused study for political and industrial decision-makers and for planning the expansion and investment needs for grid and pipeline infrastructure.** It indicates that a rapid expansion of renewable energy, far beyond most existing plans, is necessary to satisfy the projected domestic demands and facilitate early exports. The planning studies listed either do not consider early export volumes or focus only on the electricity sector.

Key conclusions

- All scenarios identify unprecedented wind and solar installations as the most cost-efficient energy sources, with NZ and NZEE requiring 9 to 21 GW more capacity by 2030 than CP (41 GW) and NZEE surpassing NZ by an additional 92 GW by 2050 (30% higher than NZ's). These substantial installations necessitate significant grid enhancements at a local level to be able to connect and integrate the expanded capacity.

- Battery capacity is needed after 2030, going up to 46 to 50 GW. This presents an opportunity for embedding value chains, which has been explored in the South African Renewable Energy Masterplan. Localised manufacture of battery components can be supported by a repurposing of the 12i tax incentive for Greentech manufacturing. [13]
- By 2040, between 5 and 10 GW of gas turbines are projected across scenarios, primarily as backup capacity for peak loads rather than as base load providers.
- To reach the 2050 capacity goals, average annual expansions for wind and solar must significantly accelerate. In the NZ scenario, the average annual build rate is 3.6 GW/year for wind and 5.0 GW/year for solar between 2030 and 2040. In NZEE, to exploit high export opportunities, annual build rates reach 6.0 GW/year for wind and 7.8 GW/year for solar in the same period. These build rates far exceed current national plans, emphasizing the need to incorporate export potential into future planning.
- The NZEE scenario's renewable capacity projections are significantly higher than those in existing studies, especially for wind, with differences of up to +279% compared to IRP2023.
- This comparison highlights the significance of NZEE and this PtX-focused study for political and industrial decision-makers and for planning the expansion and investment needs for grid and pipeline infrastructure. It indicates that a rapid expansion of renewable energy, far beyond most existing plans, is necessary to satisfy the projected domestic demands and facilitate early exports.

4.1.3 Hydrogen Balance and Capacities

The next figure provides a detailed look into the hydrogen balance, with supply from H_2 electrolysis (positive) and the demand across different sectors such as ammonia synthesis and other industry applications (negative values). Hydrogen supply and demand ramp up significantly across all scenarios, particularly in NZEE, indicating the high impact of the export targets defined for PtL fuels and green ammonia.

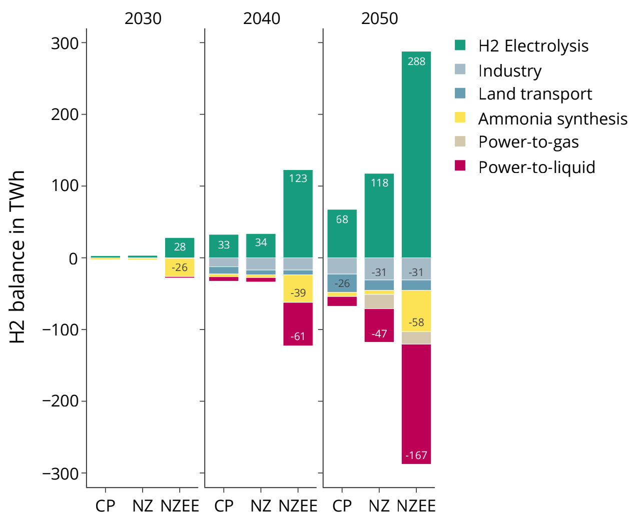


Figure 64: Hydrogen balance with supply (+) and demand (-) for CP, NZ, and NZEE.

By 2030, the CP and NZ scenarios are characterized by modest hydrogen production of 2.8 $TWhH_2$ and 3.3 $TWhH_2$ for ammonia synthesis and initial green PtL synthesis. NZ is slightly higher due to the assumption that South Africa starts to produce green ammonia for green fertilizers for the region. The NZEE scenario, which places a higher emphasis on early hydrogen exports and PtX technologies, already shows substantial hydrogen production of 28 $TWhH_2$ or around 850ktH_2 in 2030. The ammonia produced in all scenarios is primarily for export. These results show that the model chain used for the analysis in this study (SATIMGE & PyPSA-RSA-Sec, see chapter 2) does not find domestic, large-scale use of hydrogen in transport or industrial sectors to be cost-optimal by 2030.

By 2050, hydrogen production ramps up across all scenarios, but with significant differences in scale. In **CP** and **NZ**, hydrogen production reaches **68 to 118 $TWhH_2$ or about 2-3.5 Mtpa**. This is driven largely by meeting hydrogen demands for heavy-duty transport (FCEV) of 14 $TWhH_2$ (NZ) to 26 $TWhH_2$ (CP), industry feedstock, ammonia synthesis, mining trucks, and, to a limited extent, industry process heat demands of 28 $TWhH_2$ (CP) to 36 $TWhH_2$ (NZ). Notable hydrogen demands in the net-zero pathways result from the need to produce PtG for domestic use and PtL for both domestic use and export targets. The hydrogen needs for P**tG range from 17 to 20 $TWhH_2$** and **H_2 demands for PtL rises to a significant 47 $TWhH_2$ in NZ and 167 $TWhH_2$ in NZEE**. As shown, the hydrogen production and consumption levels for domestic use are higher, aimed at reaching an ambitious CO_2 target. However, it is also used in the delayed CP scenario. For transport applications, the consumption of the CP scenario in 2050 is even higher because fewer efficiency measures are implemented compared to NZ.

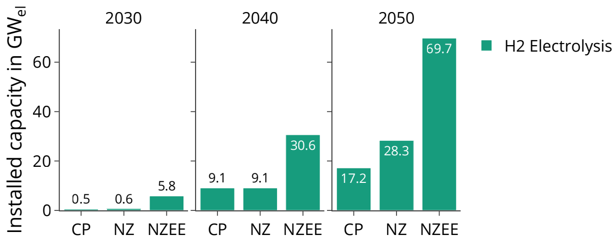


Figure 65: Installed hydrogen generation capacity in GWel for CP, NZ, and NZEE.

To summarise, the NZEE scenario stands out with a large-scale hydrogen production of 288 $TWhH_2$ in 2050. **This massive increase is caused by the high demand for PtL fuels (-167 $TWhH_2$) and 58 $TWhH_2$ for ammonia synthesis.** This reflects the scenario's extra ambition of producing hydrogen-derived products for export (with 5.8 Mtpa in total) while reaching climate neutrality for land transport, aviation, and shipping demands (which are the same as in NZ). The NZEE scenario demonstrates the potential for South Africa to not only meet its own hydrogen demands but also to become a major high-value hydrogen-derivative exporter for global markets, with a focus on carbon-free ammonia and green liquid fuels. The comparison with the current production capacities of Sasol Secunda for synthetic Fischer-Tropsch fuels (7.5 - 7.7 Mtpa Fischer-Tropsch fuels) [22] illustrates the challenge of the scenario. In addition to the high renewable capacity additions, the existing Secunda capacities would have to be reutilised and increased by 26 to 30%. This 30% increase could theoretically also be achieved by activating PetroSA's gas-to-liquid capacity in Mossel Bay (approximately 2.2 Mtpa).

The next sections show the technologies and sectors that consume and use PtL and PtG products. Section 4.3 summarises the drivers for hydrogen export.

The installed hydrogen generation capacity starts with 0.5 to 0.6 GWel in CP and NZ. It increases to **9.1 GWel by 2040 and 17.2 to 28.3 GWel** (65% higher in NZ than CP) by 2050. In the NZEE scenario, the ramp-up of hydrogen capacity is much more ambitious. By **2030, NZEE** achieves **5.8 GWel** of installed capacity. This capacity increases drastically to 30.6 GWel in 2040 and more than doubles by **2050, reaching 69.7 GWel**. The installed hydrogen capacities in **2040 and 2050 are 3.4 to 2.5 times higher than in NZ.**

Analysing the H_2 strategies and studies published over the past three years (see introduction), it is evident that the NZEE scenario in this study offers supplementary figures and insights. For example, the GHCS only states that **41 GW** of electrolysers are required for the base scenario (3.8 Mtpa). In comparison with the figures of the scenario presented, the base case of the GHCS is comparable with the NZ scenario. **With 28 GW, 3.5 Mtpa are produced in NZ. NZEE anticipates 70 GW for 8.6 Mtpa H_2**, which is slightly above the uplift scenario of the GHCS. On the other hand, we are below the anticipated project capacities of the SA H_2 Society Roadmap of 2021, which targets 10 GW of electrolysis in the Northern Cape and 1.7 GW in the Hydrogen Valley by 2030. The NZEE scenario is on the upper bound of the ambitions of the **NBI study**, which estimates that green H_2 demand will amount to **8.5-9.5 million tonnes by 2050 (including exports)** with a required total renewable energy capacity of 360 to 390 GW (the total renewable capacity of NZEE in this study are 396GW).

Key conclusions

- By 2030, the large-scale utilisation of hydrogen in South Africa for transport and industry is low or non-existent in all scenarios. By 2050, the direct hydrogen demands in CP and NZ of in total 68-118 TWh or 2-3.5 Mtpa are dominated by industry (28-36 TWh), heavy-duty transport (14-26 TWh), Power-to-Gas (17-20 TWh) and PtL (0 in CP, 47 TWh in NZ). [16]

---

16 This hydrogen consumption also includes secondary energy consumption. Further results on consumption per sector follow in the next chapters. For details on assumptions for final energy consumption, see also chapter 3.5.2.

- By 2050, the NZEE scenario significantly outpaces the CP and NZ scenarios in hydrogen production, reaching 288 TWh H_2 (or 8.6 Mtpa). This growth is driven primarily by the high target for PtL fuels and green ammonia export, highlighting South Africa's potential to become a major exporter of hydrogen-derived products.
- The NZEE scenario requires a substantial ramp-up of hydrogen electrolysis capacity, from 5.8 GWel in 2030, to 31 GWel by 2040, to 70 GWel by 2050. This is coupled with the need for infrastructure, supportive policies and significant expansion in renewable capacity (396 GW in total). With the hydrogen production levels for domestic use and for export, NZEE aligns with the ambitions of the GHCS uplift scenario and the NBI net-zero study for South Africa.

4.1.4 Liquid Fuels and Methane Balance

In all scenarios, liquid fuel consumption decreases significantly from 2030 to 2050, driven by the transition to alternative mobility concepts, electromobility or other alternative engines, though at different paces. In the CP scenario, liquid fuel consumption of land transport is 237 TWh in 2030, falls to 167 TWh in 2040 as some electrification takes place, and falls to 16 TWh in 2050, assuming a longer reliance on traditional fuels than in the other scenarios. In contrast, the NZ and NZEE demonstrate a more accelerated reduction in liquid fuel use. By 2040, liquid fuel consumption in NZ/NZEE is 43% lower than in CP, underscoring the impact of NZ and NZEE's stronger policies and the impact of earlier price-parity of electric mobility. Liquid fuel consumption for national and international aviation and shipping remains relatively stable or increases slightly until 2050.

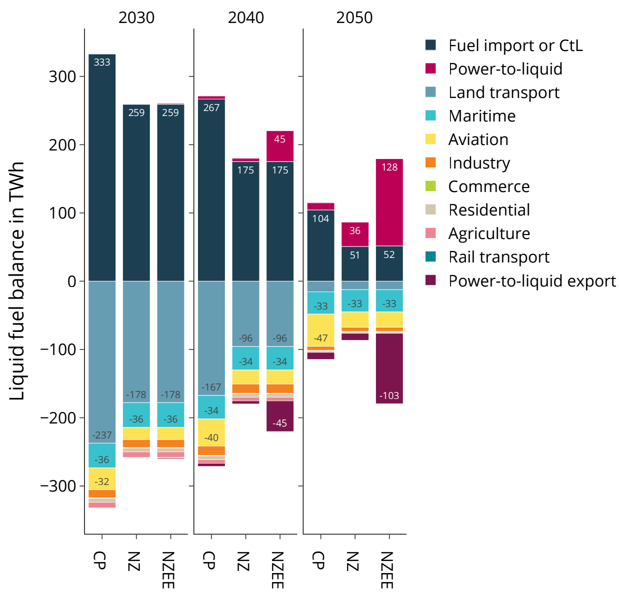


Figure 66: Liquid fuel balance with supply (+) and demand (-) for CP, NZ, and NZEE.

The demands are met by fuel imports or Coal-to-liquid synthesis in 2030. Green Power-to-liquid (PtL) fuels synthesis begin to emerge at a significant scale by 2040 for exports, with 4.5 TWh allocated for export in CP and NZ and 45 TWh for exports in NZEE. By 2050, PtL export volumes increase to 10 TWh in CP and NZ and to 100 TWh in NZEE. Beyond PtL synthesis for export, NZ's and NZEE's CO_2 constraints require the production of a further 26 TWh of green fuels, which represents 33% of the remaining domestic consumption for land transport, aviation, shipping and industry. **Assuming that all synthetic green fuel is supplied to the aviation and shipping sectors, this results in an approximate 50% share of e-fuels for these sectors.**

To summarise, in the NZEE scenario, liquid fuel consumption drops similar to NZ, but also sets-up large-scale power-to-liquid fuels production for direct or indirect (via bunkering) export. Hence, what distinguishes **NZEE from NZ is the ambitious ramp-up in PtL exports, which reach 103 TWhFT or 8.31 Mt by 2050**. As previously highlighted, a comparison with Sasol Secunda's current synthetic Fischer-Tropsch fuel production capacity (7.5 - 7.7 Mtpa) [22] underscores the ambitious scale of the scenario. Beyond substantial new renewable capacity, existing Secunda production would need to be repurposed and expanded by an additional 26 to 30%. This expansion could, in theory, be supported by activating the mothballed PetroSA's gas-to-liquid facility in Mossel Bay, which has an approximate capacity of 2.2 Mtpa.

Across all scenarios, methane imports range between 37 to 41 TWh in 2030, driven primarily by industrial consumption (34 to 37 TWh) and minor use in gas turbines (3 to 4 TWh) and for heating in commerce. The drop of gas consumption in industry from 2030 to 2040 is mainly caused by decrease of gas-to-liquid refinery of – 14TWh (included in industry demand), a decrease of usage as a feedstock for chemicals (-3.1 TWh), a reduction of gas consumption for BF BOF iron & steel production (-2.7 TWh) and less use for process heating.

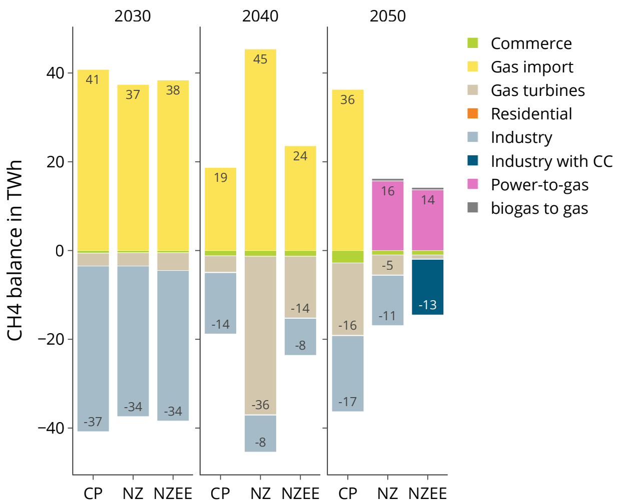


Figure 67: Methane (CH4) balance with supply (+) and demand (-) for CP, NZ, and NZEE.

Looking more closely at the demand side of the scenario CP reveals, that there is little use of gas in gas turbines for electricity generation in 2030 and 2040, as coal-fired power stations are still a large contributor. As a result, imports drop to 19 TWh as industry reduces its gas reliance by 2040, but gas imports rebound to 36 TWh by 2050 as gas turbines become relevant as dispatchable generation (16 TWh). The drop in gas imports and consumption in 2040 in this scenario will cause problems in the real world because the business case for gas import and distribution infrastructure requires stable take-off at a level that makes the upfront investments in the LNG and pipeline infrastructure profitable and bankable. It should be noted here, that the requirement for would be higher, if the expansion of renewables is restricted beyond the regional restrictions that were applied for the cape regions in this study. Chapter 4 analyses the impact of a globally restricted wind expansion.

In the NZ and NZEE scenarios, methane uses in industry decline more rapidly as the usage of natural gas for the production of grey ammonia is phased-out. But **in NZ, by 2040, the electricity gas turbines consumption of 36 TWh, which is the highest value among scenarios, push imports slightly up to 45 TWh** (+10% more than 2030). In **NZEE, shows less dependency on gas for electricity supply with only 14 TWh by 2040**. This is likely due to higher surplus electricity from renewables for H_2 electrolysis. However, **by 2050, imports drop to zero and the synthetic production of 14 to 16 TWh green methane replaces the need of fossil gas in both scenario NZ and NZEE**. In contrast to NZ, the methane used for used for cement and chemical processes (12.5 TWh) is paired with carbon capture (90% capture rate) by 2050 to capture unavoidable process emissions. The carbon captured is then utilised and required to provide the system with usable carbon as feedstock for PtG and PtL fuels.

From a national perspective, **the currently planned LNG import capacities in Richards Bay of 5 million tonnes (or 77 TWh) would be sufficient for the gas consumption shown here.** The gas consumption of our analysis is low compared to other studies, such as the **NBI study. The NBI study expects a temporary consumption of 94 TWh in 2040 (around 50 TWh more)** [15]. The use of gas for gas-fired power plants depends on the assumed electricity consumption, gas import prices and boundary conditions such as a minimum off-take volume to guarantee the profitability of the infrastructure. With regard to the technical and economic feasibility of a fossil gas import and pipeline infrastructure, the time-limited utilisation of gas in the NZ and NZEE scenarios is a challenge. Supply contracts and any planning should be limited to a maximum of 20-25 years, taking into account a net-zero pathway. Furthermore, the switch to synthetic gas should be planned from today onwards. In-depth sensitivity analyses in further studies can provide more certainty.

Regarding PtX, the results show that under the emission reduction targets defined in the three main scenarios, synthetic methane is seen as necessary by the model. However, the need and the timing for synthetic and green PtG to meet certain emission levels by 2050 or beyond apparently depends on system-wide or sector-specific CO_2 targets. The import of slightly higher or lower system-wide targets for 2050 are analysed in the sensitivity analysis (see section 4.2.0).

Key conclusions

- Liquid fuel consumption for land transport decreases significantly across all scenarios, driven by a shift towards alternative mobility solutions and the growing adoption of electromobility. The reliance on fossil fuels drops faster (43% lower) in NZ and NZEE compared to CP by 2040.
- Green Power-to-Liquid (PtL) fuel synthesis starts to scale significantly after 2030, mainly to meet export demands. By 2040, PtL exports reach 4.5 TWh in both CP and NZ, while NZEE targets an ambitious 45 TWh. By 2050, these export volumes increase further, with CP and NZ at 10 TWh and NZEE reaching 100 TWh (or 8.3MtFT), highlighting NZEE's emphasis on establishing South Africa as a major PtL exporter in global markets.
- NZ and NZEE scenarios incorporate additional green PtL production to meet CO_2 constraints, with 26 TWh allocated to supply green fuels for aviation and shipping by 2050, representing a e-fuel share of 50%.
- In order to achieve the ambitious export targets that are possible by 2040, early planning must be a priority for CCU infrastructure as well as carbon transportation pipelines, which should be built during the 2030's.
- Negotiations with the EU to amend the RED & DA on the free allocation of electrons should also be prioritised to allow e-SAF produced at a transitioning Secunda site to be eligible under the RFNBO regulations.
- An international book and claim system for e-SAF would enable the use of the fuel produced at secunda to enter the global aviation market with minimal need for transportation.

4.1.5 Carbon Capture and Usage and Water Balance

In the CP and NZ scenarios, the balance between CO_2 capture and usage remains relatively modest compared to NZEE. By 2040, both scenarios show 1.2 $MtCO_2$ captured from industrial processes with carbon capture (CC) for power-to-liquid (PtL) production. By 2050, the CO_2 capture and usage volumes double in CP and is ten times larger in NZ, with 2.7 $MtCO_2$ and 12.3 $MtCO_2$ captured from industrial processes. 3.2 $MtCO_2$ is consumed for PtL production in CP, but in NZ the needs are higher with 9 $MtCO_2$ required for PtL and 3.1 $MtCO_2$ for PtG.

In the NZEE scenario, the CO_2 balance is much larger and more complex. By 2040, the volume is ten times higher compared to the other scenarios, with 11.6 $MtCO_2$ captured from industrial processes and the same volume used for PtL production. By 2050, the NZEE scenario ramps up the capturing of unavoidable process emissions to 21 $MtCO_2$ and integrates more CO_2 capture options, including 8.1 $MtCO_2$ from biomass with CC, 3.7 $MtCO_2$ from direct air capture. CO_2 consumption for PtL ramps up significantly, using 32.8 $MtCO_2$, and PtG uses 2.7 $MtCO_2$.

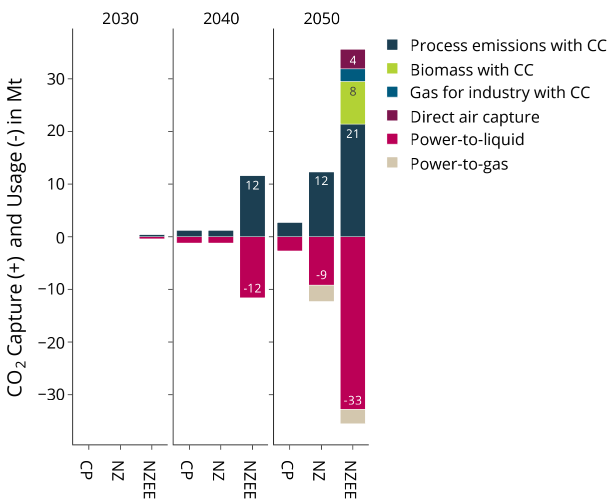


Figure 68: CO2 feedstock balance with capture volumes (+) and usage volumes (-) for the PtX products analysed (without CtL) in the scenario CP, NZ, and NZEE.

The results demonstrate the scenario's need to capture and utilise large amounts of CO_2 for green fuel production and emissions reduction. Notably, the model chooses to exploit the capture and usage of unavoidable emissions before DAC. Capturing from the power sector or coal-to-liquid process is not an option. The availability of process emission capturing is likely a key advantage for cost-competitive PtL fuel production, use and export and presents a key advantage compared to countries without local cement and chemical industries before DAC becomes available at lower costs.

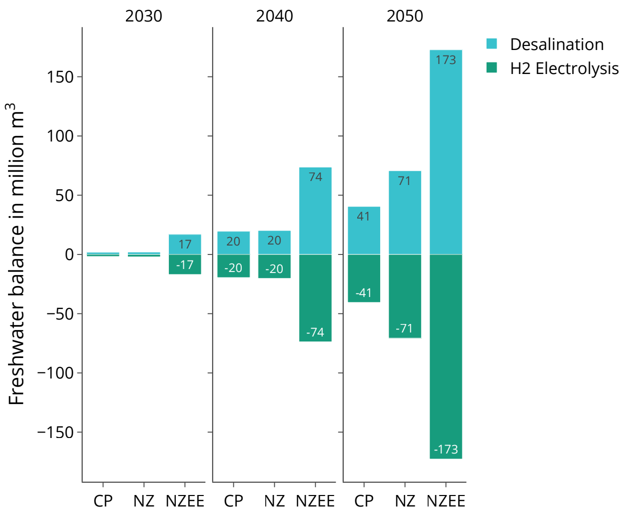


Figure 69: Freshwater balance with supply (+) and demand (-) for CP, NZ, and NZEE.

A cross-check with a recent study on the CO_2 capture potential in South Africa (see Table 10), led by the PtX Hub, supports the figures presented in Figure 68 and goes into detail on the CO_2 sources available in South Africa. The reader is referred to this study for details of available sources for process emissions and transport of captured carbon. It is also recommended that future studies carefully evaluate the best CO_2 feedstock sources in terms of regulatory constraints and infrastructure requirements to avoid stranded investments.

The scenario configuration requires that the same amount of water consumed by H_2 electrolysis is also desalinated via seawater desalination.

The figure shows the seawater desalination requirements, measured in million cubic meters (m^3) of water, necessary for producing fresh water for hydrogen electrolysis across different scenarios from 2030 to 2050. In the CP scenario, desalination needs start at 1.7 million m^3 in 2030 and grow significantly to 19.5 million m^3 by 2040 before further increasing to 40.5 million m^3 by 2050 (+108% from 2040). In the NZ scenario, desalination requirements begin slightly higher at 2.0 million m^3 in 2030, rising to 20.2 million m^3 by 2040 and surging to 70.6 million m^3 by 2050 (+249% from 2040), reflecting the higher hydrogen needs for domestic PtX compared to CP. The NZEE scenario, focused on high export targets, requires much larger desalination volumes, starting at 16.9 million m^3 in 2030 and escalating to 73.7 million m^3 by 2040 (+336%), then reaching 172.7 million m^3 by 2050 (+134% from 2040). This trend underscores the substantial increase in water demand for hydrogen production as defossilisation and export goals intensify, particularly in the NZEE scenario where the desalination requirements are over four times higher than CP by 2050.

To put that into context, the quantities of water required are less than the water consumption of coal-fired power generation in the last decades. According to a study by the CSIR, the coal-based energy sector consumed 282 billion cubic metres of water in 2015. [111]

It is also important to note that the costs for seawater desalination account for less than 1% of the costs for hydrogen production. This has also been shown by previous analyses.

Key conclusions

- By 2050, the NZEE scenario demands extensive CO_2 capture – 21 $MtCO_2$ from industrial processes, with additional capture from biomass and direct air sources – driven by high PtL and PtG fuel production needs. This level far exceeds CP and NZ, highlighting NZEE's focus on export-ready green fuels.
- To meet hydrogen electrolysis needs, desalination requirements rise across scenarios, with NZEE reaching 172.7 million m^3 by 2050 – over four times the CP demand. This substantial water use reflects NZEE's ambitious hydrogen and export targets but remains significantly below the historical water consumption of coal-fired power plants.
- In general, a long coastline for seawater desalination and many sources for capturing CO_2 positions South Africa competitively in the global PtX market. With regard to these by-products, it will be important to keep an eye on the development of the regulatory framework in South Africa and with trading partners in the future.

4.1.6 System Costs and Export Revenues

A view of the composition of system costs (Figure 70) reveals the significant change from a variable fuel-heavy cost structure with a high share of oil and coal fuel costs in 2030 to a CAPEX-heavy cost structure with technologies such as wind, solar and H_2 electrolysis plants by 2050.

The total CAPEX and OPEX expenses of the scenarios are 34.2 (CP), 29.1 (NZ) and 31.9 (NZEE) billion USD in 2030. By 2050, the expenses amount to 36.5 (CP), 35.5 (NZ) and a substantially higher 51.2 (NZEE) billion USD.

Regarding revenues from exports, the figure highlights the stark contrast between the low-export pathways of CP and NZ and the high-export strategy of NZEE. In the CP and NZ scenarios, export revenues from ammonia and power-to-liquid (PtL) fuels rise from 0.3 billion USD in 2030 to 2.6 billion USD by 2050. In contrast, the NZEE scenario reaches much higher export revenues with 2.2 billion USD by 2030 and an increase to 21.6 billion USD by 2050, driven by its focus on large-scale hydrogen-derived product exports. [17]

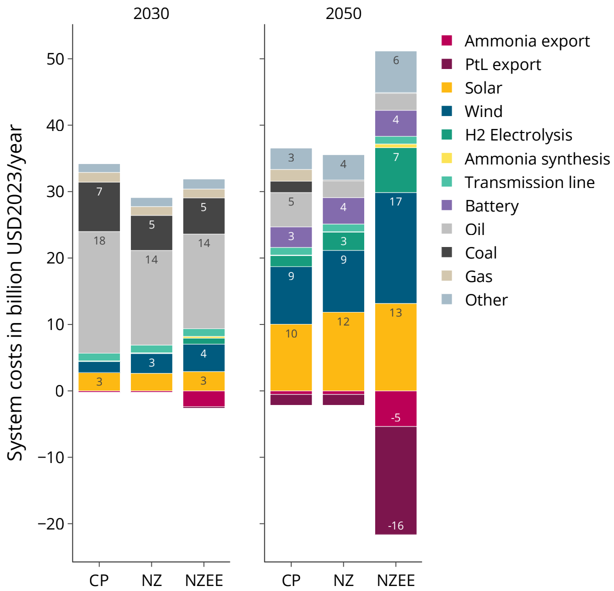


Figure 70: Annualised system expenses (+) and revenues via export (-) for CP, NZ, and NZEE in USD2023. [1]

These higher revenues result in net system costs (see next table) in NZEE of 29.3 billion USD per year in 2030 and similarly 29.5 billion USD by 2050. Therefore, NZEE is the least-cost pathway in the long term, particularly due to the high export revenues. Despite this it doesn't achieve substantial cost reductions by 2030 due to exports. The early phase of NZEE exports is only marginally system-cost-neutral, indicating that the long-term benefits of high export volumes take time to materialize.

Table 26: Net system costs for each 2030, 2050 and each scenario.

Year	Scenario	Net System Cost 2050 (billion USD/year)
2030	CP	33.9
	NZ	28.8
	NZEE	29.3
2050	CP	34.4
	NZ	33.4
	NZEE	29.5

17 The currency exchange rate between USD2023 and ZAR2023 is 18.4527.

Key conclusions

- The energy system evolves from a fuel-dominated cost structure in 2030, reliant on oil and coal, to a CAPEX-intensive structure by 2050, with significant investments in wind, solar, and H_2 electrolysis technologies.
- By 2050, total system expenses in NZEE reach 51.2 billion USD – higher than CP and NZ – offset by export revenues of 21.6 billion USD from ammonia and PtL fuels, showcasing the revenue potential of large-scale hydrogen exports.
- Due to high export revenues, NZEE becomes the most cost-effective scenario by 2050, despite being slightly more expensive in 2030, as substantial export profits take time to develop.

4.1.7 High-level Estimation of Job Creation

Although preliminary, a high-level analysis was conducted to estimate job creation potential. The analysis is based on employment factors, localisation factors and assumptions on scaling effects, which reduce the job effect per MW installed or operated. Employment factors are taken from Electric Power Research Institute (EPRI), which were also used and referenced in the Northern Cape Green Hydrogen Masterplan report [23], and calibrated (reduced) based on job estimations and localisation factors of the South African Renewable Energy Masterplan (SAREM). For instance, the SAREM baseline localisation factors for the local content of manufacturing and associated services for the renewable energy sector range from 20-47%. The following table provides job intensity metrics for different energy technologies, measured in terms of jobs per megawatt (MW) across three phases: construction & installation, operations & maintenance, and component manufacturing.

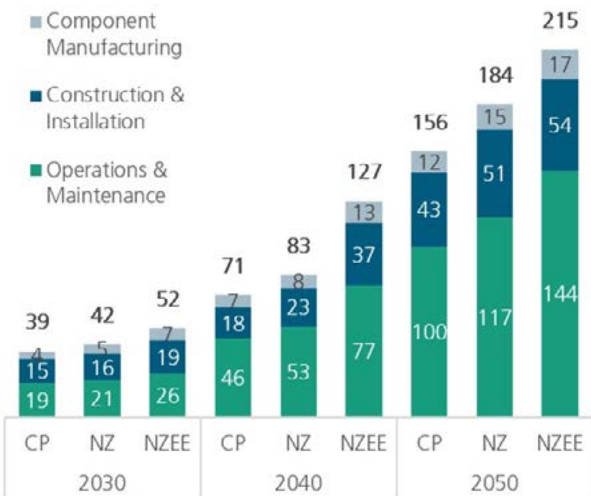


Figure 71: Indicative estimation of potential job creation effect in thousand jobs per year (kjobs/year) for operation and maintenance, construction and installation, and component manufacturing for each time horizon and scenario.

Table 27: Indicative technology-specific employment factors, taken from literature and reduced to align with estimates in the SAREM Masterplan. Sources [19, 23].

Tech Technology	Construction & Installation [jobs/MW]	Operations& Maintenance [jobs/MW]	Component Manufacturing [jobs/MW]
Solar	4.8	0.6	1.1
Wind	1.1	0.2	0.7
H_2 Electrolysis	0.6	0.10	0.6

The resulting job creation effects of the three main scenarios between the years 2030 to 2050 are displayed in Figure 71. **Total estimated employment impacts range from 39 to 52 (NZEE) thousand jobs per year by 2030 and from 156 to 215 thousand jobs per year by 2050.** In line with the higher renewable energy capacities, the associated job effects of renewables are +18% to 34% % higher in NZ and NZEE than in CP in 2050. The fraction of jobs for operations and maintenance is around 67%. This is also due to the fact that it is assumed that only 30% of manufacturing jobs will be located in South Africa. The potential for manufacturing jobs is higher. In comparison, the IHS Markit analysis of a "Super H_2igh Road" scenario for South Africa estimates 370.000 net additional jobs by 2050, assuming an increase of the local content of the added value from around 50% to 70% by 2050.

These jobs effects only result from a factor-based estimate for solar, wind and H_2 electrolysis capacities. Investments in various other technologies would further add to job creation beyond the presented numbers. It is important to note that this is a very simplified assessment of the socio-economic impact regarding jobs. The reader is referred to more in depth analysis on employment: [112]. Also, future studies should conduct more in-depth analysis to understand the socio-economic potential.

4.1.8 Spatial Analysis for Electricity

As detailed in Chapter 2, the optimisation was carried out using a multi-regionally (11-regions) resolved energy system model. Industrial consumption is allocated to the regions based on available site-specific data. It is also defined that only model regions with a coastline can export ammonia and PtL fuels. The electricity flow between the nodes is optimised using a linear optimal power flow formulation. The flow of hydrogen via pipelines between regions is optimised based on a transport problem formulation. Grid expansion and H_2 pipeline optimisation for connecting the model nodes is possible. This chapter will examine the findings of the spatial allocation of new generation capacities, the reinforcement of electricity grid transmission, and the expansion of battery storage. The next chapter 4.1.9 presents the results for the allocation of hydrogen electrolysis capacity and the need for hydrogen transport via constructed pipelines.

In general, the optimal allocation of new renewable generation and hydrogen electrolysis capacities depends on the full load hours of renewables per region (see section 2.7.2), the expansion restrictions per region (see section 2.7.3), the exogenous and endogenous demands per region and the available transfer capacities (see section 2.7.4).

Figure 72 to Figure 75 illustrate the regional installed electricity generation, storage and transmission capacities for the scenarios NZ and NZEE and for the years 2030 and 2050. Figure 76 illustrates the results for CP and for the year 2030.

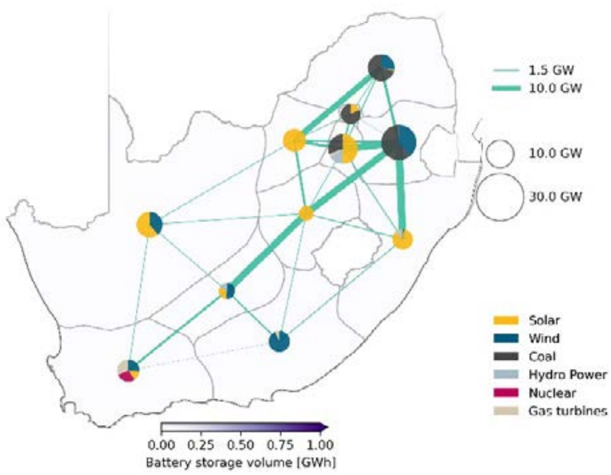


Figure 72: Map of installed electricity generation, storage and transmission capacities by 2030 in the scenario NZ.

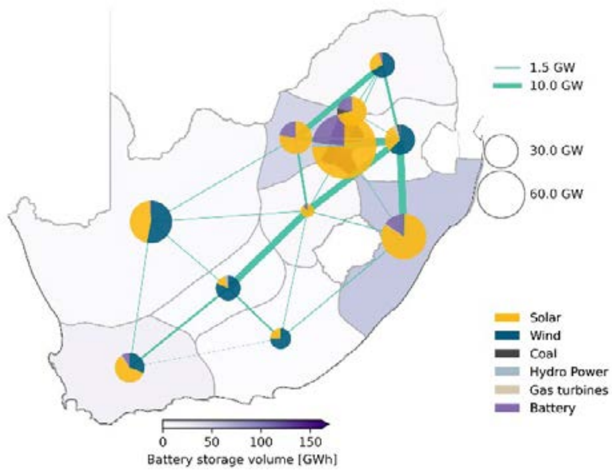


Figure 73: Map of installed electricity generation, storage and transmission capacities by 2050 in the scenario NZ.

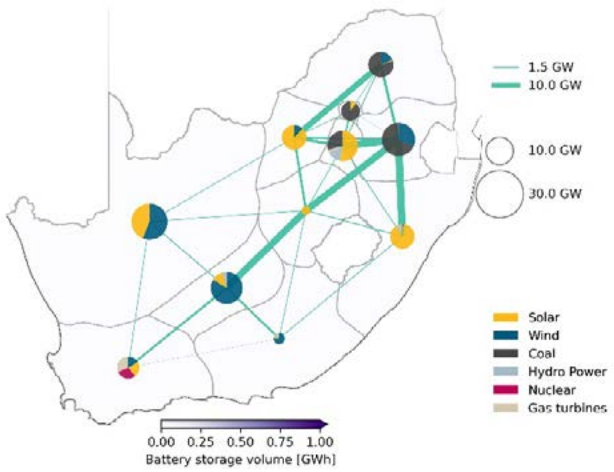


Figure 74: Map of installed electricity generation, storage and transmission capacities by 2030 in the scenario NZEE.

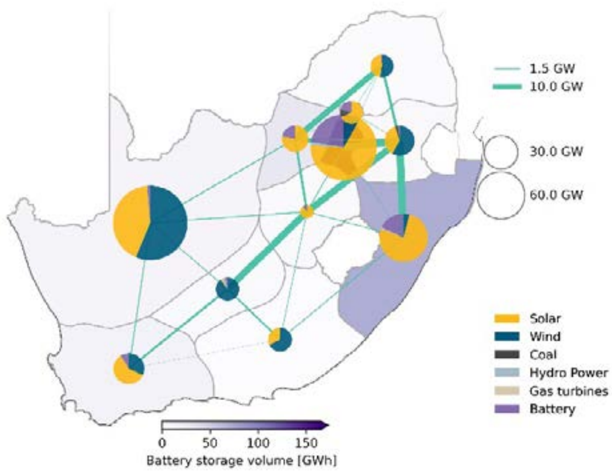


Figure 75: Map of installed electricity generation, storage and transmission capacities by 2050 in the scenario NZEE.

Renewables

Installed capacities by 2030

In comparing the spatial distribution of solar and wind capacities across scenarios by 2030, NZEE shows a notable increase in renewable capacity, especially in regions like the Northern Cape and Hydra Cluster leveraging the favourable resource potential of these areas without regional limitations for installing and using renewables. [18] In the Northern Cape, the installed renewable capacity in NZEE is 17 GW, almost double the capacity in CP and NZ (each around 9 GW). This substantial difference highlights the mentioned focus on utilizing the high solar and wind potential. Similarly, in the Hydra Cluster, NZEE features 13 GW of renewable capacity, a major increase from the 3 GW seen in both CP and NZ. Wind capacity additions dominate the expansion in the Northern Cape and Hydra Cluster.

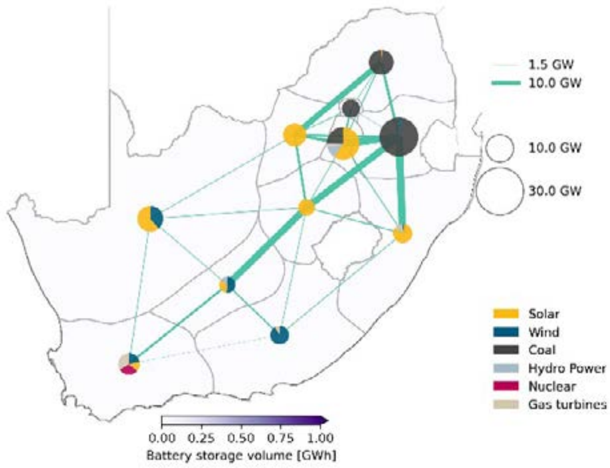


Figure 76: Map of installed electricity generation, storage and transmission capacities by 2030 in the scenario CP.

In contrast, Gauteng, with a renewable capacity of around 6 GW across all scenarios, shows a more balanced share of wind and solar capacity. KwaZulu Natal's renewable capacity in NZEE reaches 7 GW, significantly higher than the 4 GW in CP and 5 GW in NZ, largely driven by solar installations. Mpumalanga introduces low levels of RES in CP but expands RES in both NZ and NZEE (6.4 GW and 4.7 GW, respectively) to replace retiring coal capacity.

Installed capacities by 2050

By 2050, renewable capacity potential is utilised across all regions. Due to relative advantages, solar PV expansions are higher in Pelly, Gauteng, and KwaZulu Natal, while wind installations dominate the Northern Cape, Hydra Cluster, Eastern Cape, Mpumalanga, and Limpopo (outside the national parks) across all scenarios.

18 As a reminder, in CP and NZ, installations are limited until 2030 in the Cape regions, based on the results of the GCCA over the last two years. In NZEE, a higher level of grid infrastructure support or partially stand-alone PtX structures are assumed.

The absolute figures vary significantly between NZ and NZEE, with NZEE showcasing far higher overall capacities in key regions. In the Northern Cape, solar capacity in NZEE reaches 62 GW, compared to 22 GW in NZ, with a substantial difference of 40 GW. Wind capacity is even more pronounced, with NZEE attaining 82 GW compared to 25 GW in NZ, marking a 57 GW increase. In the Eastern Cape, NZEE exceeds NZ with 5 GW of solar versus 3 GW and 10 GW of wind compared to 9 GW in NZ, demonstrating NZEE's higher reliance on renewable energy sources in this region.

Some regions, like KwaZulu-Natal, show slightly reduced solar capacity in NZEE compared to NZ, with 47 GW in NZEE versus 45 GW in NZ. However, wind capacity is notably higher in NZEE, reaching 2.4 GW compared to 0.1 GW in NZ. Overall, NZEE emphasizes substantially larger installations of renewable capacities, especially in regions like the Northern and Eastern Cape, highlighting a more ambitious pathway for renewable energy deployment in 2050.

Dispatchable generation

As designed in the CP scenario, coal capacities continue to dominate in 2030, with approximately 20 GW in Mpumalanga and ~8 GW in Limpopo (See Figure 76). In other scenarios, half of Mpumalanga's coal capacity is phased out by 2030. For further dispatchable generation, model results indicate that gas turbines are required similarly across KwaZulu Natal, Gauteng, Eastern Cape, and primarily in Western Cape, which provides around 1.7 GW across all scenarios in 2030.

For large-scale storage, the model does not predict significant battery storage requirements for load balancing by 2030 within the system boundary, though it's worth noting that distribution grids are not modelled, and a certain degree of load flexibility is assumed from battery electric vehicles added in 2030.

While the model sees no need for batteries in 2030 for the modelled system, the total storage volumes in 2050 across the 11 regions range from 146 GWh in CP to 211 GWh in NZEE. Gauteng is the region with the largest capacities, with a storage volume of 116 GWh in CP, 161 GWh in NZ, and 165 GWh in NZEE, accounting for around 55% to 77% of the total capacity. Battery storage dispatch power is 18.2 GW in Gauteng for CP, increasing to 25.3 GW in NZ and 25.7 GW in NZEE, illustrating the critical role of electricity system flexibility in this high-demand, solar-rich province as South Africa progresses toward net-zero emissions by 2050. In contrast, regions like Mpumalanga, Eastern Cape, and Limpopo maintain relatively low battery storage capacities across scenarios, highlighting limited local storage needs under the modelled solution. It is also worth noting that the model optimally leverages the transmission grid, yet distribution grid constraints were not included in this modelling. Additionally, 50% of battery electric vehicles are assumed to support grid flexibility through smart charging.

Region-wise electricity supply and demand

Table 28: Region-wise electricity supply and demand by 2050 for the scenarios NZ and NZEE.

	Supply (TWhel)		Demand (TWhel)		Demand of H_2 electrolysis (TWhel)	
Model region	**NZ**	**NZEE**	**NZ**	**NZEE**	**NZ**	**NZEE**
Gauteng	136	156	152	158	26	33
KwaZulu Natal	68	76	86	86	0	0
Western Cape	44	49	64	66	8	10
Eastern Cape	27	35	42	47	17	22

North West	36	25	24	24	0	0
Limpopo	33	27	28	28	0	0
Mpumalanga	47	47	44	47	21	24
Free State	6	7	14	14	0	0
Pelly	25	15	16	13	5	2
Northern Cape	110	345	98	331	88	315
Hydra Cluster	43	40	1	1	0	0

It should be noted that the spatial disaggregation of sectoral demand by region is simplified in the first cross-sectoral model version used here.

Electricity Grid Capacity

Under our assumptions and restrictions, for some branches, the electricity transmission capacities remain unexpanded. For example, key lines like Free State to Hydra Cluster (16.4 GW), Gauteng to Mpumalanga (18 GW) and Mpumalanga to KwaZulu Natal (18 GW) maintain their current capacity. Key candidates for line capacity expansion in NZ and CP are the connections with shorter distances, such as Gauteng to Limpopo (2.1 GW), Free State to KwaZulu Natal (2.3 GW) and Eastern Cape to Hydra Cluster (1.4 GW). In the NZEE scenario, the available expansion volume is used to strengthen the connection between the Northern Cape to Hydra Cluster and North West. This reflects efforts to improve transmission between renewable-rich hydrogen hubs and industrial areas.

While some branches of the electricity transmission capacities remain unexpanded, overall, the defined upper limit of 10% of the existing transfer capacities (amounting to an expansion volume of 5.4 TWkm) is utilised in all scenarios.

Beside interregional transmission capacity bottlenecks, the limited grid connection capacity is currently preventing the intraregional connection of new renewable capacities. For the CP and NZ scenarios, the corresponding region-wise connection capacity limits for the western regions are applied according to the generation expansion per province in the TDP (see section 3.4). According to the model results, the connection limits in the Northern Cape and Hydra Cluster are utilised in all scenarios by 2030. In the Eastern Cape only ~40% and in the Western Cape ~20% of the connection limits are utilised by 2030. In NZEE and in 2040 or by 2050 in all scenarios, however, the grid connection capacities preferred clearly exceed the limits defined for 2030 based on the latest TDP. This means that the measures specified in the TDP2023 must be implemented in order to achieve the connection capacities by 2030 or later. To achieve the connection capacity and address the existing grid's substantial constraints, particularly in regions with the best renewable capacity factors, such as the Northern, Eastern, and Western Cape, the TDP recommends approximately 170 new transformers in the mid-term and 60 new transformers in the short-term. [25]

Key conclusions

The results underscore that higher levels of hydrogen production serve as a key enabler for accessing remote renewable-rich regions such as those in the Northern Cape in all scenarios.

The outstanding difference of the NZEE is the higher capacities and therefore the higher utilisation of the best-in-class resources in the Northern Cape. In NZEE, these resources can be tapped via the optimal placement of new electricity demand from H_2 electrolysis. In the other scenarios, the electricity load is mainly where the demand centres are today. In these scenarios, synergy effects such as local electrolysis electricity demand in Northern Cape and export of surplus electricity, cannot be utilised. For this reason, the grid connections to the Northern Cape are less expanded in the low-export scenarios.

4.1.9 Spatial Analysis for H_2

H_2 electrolysis is another important component for integrating renewables. The optimal allocation depends on the renewable resources, the domestic demands, and the interaction of the electricity and hydrogen systems. Figure 77 to Figure 80 illustrate the installed hydrogen generation, storage and transport capacities for NZ and NZEE by 2030 and 2050. In addition, the hydrogen electrolysis capacities per model region are listed in Table 29.

Table 29: Installed hydrogen electrolysis capacities per region by 2050 for each scenario.

Region	CP (GWel)	NZ (GWel)	NZEE (GWel)

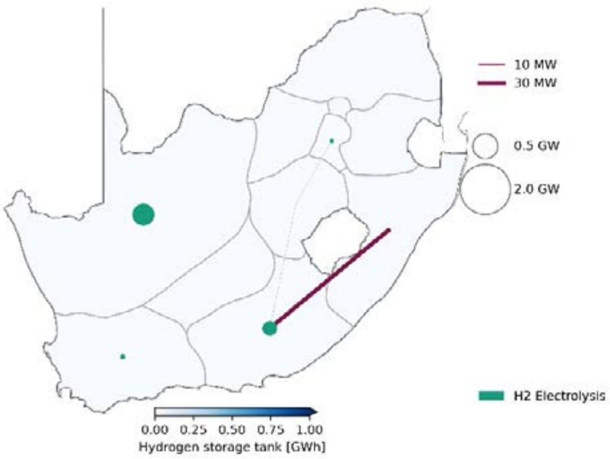


Figure 77: Map of installed hydrogen generation, storage and transport capacities by 2030 in the scenario NZ.

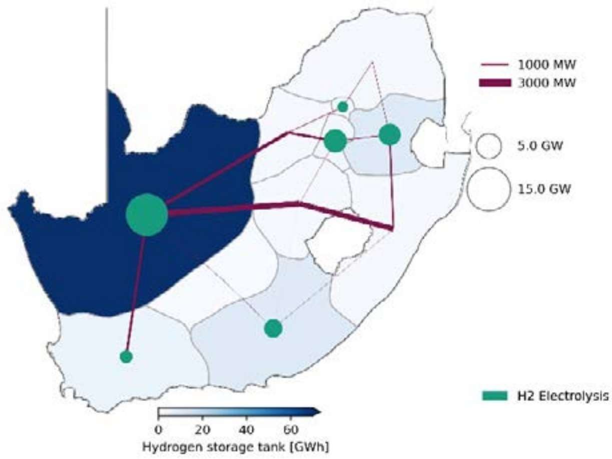


Figure 78: Map of installed hydrogen generation, storage and transport capacities by 2050 in the scenario NZ.

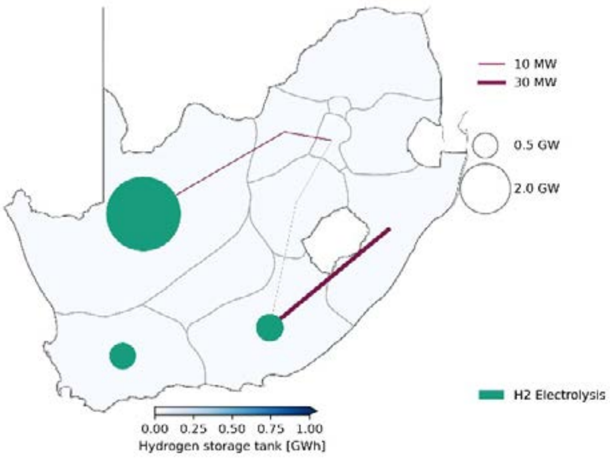


Figure 79: Map of installed hydrogen generation, storage and transport capacities by 2030 in the scenario NZEE.

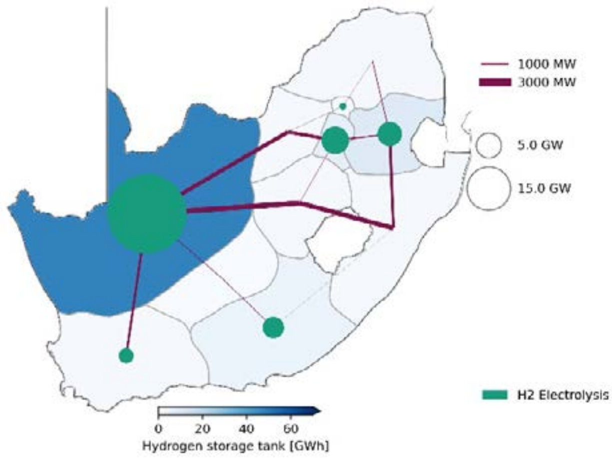


Figure 80: Map of installed hydrogen generation, storage and transport capacities by 2050 in the scenario NZEE.

Eastern Cape	1.4	2.8	3.8
Gauteng	1.3	4.5	6.3
Mpumalanga	1.9	4.0	4.9
Northern Cape	11.3	14.7	52.3
Pelly	0.7	1.0	0.4
Western Cape	0.6	1.4	1.9

By 2030, hydrogen electrolysis capacity expansion is minimal in both the CP and NZ scenarios, with most regions seeing little to no development. By 2030, hydrogen electrolysis capacity expansion remains minimal across most regions in the CP and NZ scenarios, with only modest developments. In the Eastern Cape, electrolysis capacity reaches 0.6 GW in NZEE, slightly higher than 0.2 GW in NZ and 0.1 GW in CP. The earlier adoption of green ammonia synthesis for local fertilizer production explains the slightly higher capacities in NZ compared to CP. The Northern Cape stands out in the NZEE scenario with 4.6 GW of capacity, far exceeding the 0.4 GW in both CP and NZ, indicating a focused effort on hydrogen production in this region under NZEE. The Western Cape introduces a modest 0.6 GW in NZEE by 2030, with no development in CP or NZ. Other regions, including KwaZulu Natal, Limpopo, and Mpumalanga, show no electrolysis capacity development by 2030 across any scenario. In comparison with the planned activities presented in Chapter 2.5, it is clear that the model is more focussed on the Northern Cape than the project announcements. Based on the planned projects, the capacities in the Western Cape are significantly higher than in NZEE for 2030 at approx. 2 GW.

By 2050, hydrogen electrolysis capacity expands significantly, particularly in the NZEE scenario. The Northern Cape dominates and positions as a major hydrogen production hub with a substantial 52.3 GW in NZEE or 11.3 GW in CP and 14.7 GW in NZ. The Eastern Cape also sees considerable growth, with electrolysis capacity reaching 3.8 GW in NZEE, compared to 1.4 GW in CP and 2.8 GW in NZ. Gauteng achieves 6.3 GW in NZEE by 2050, exceeding the 1.3 GW in CP and 4.5 GW in NZ. Similarly, Mpumalanga's electrolysis capacity reaches 4.9 GW in NZEE, which is higher than the 1.9 GW in CP and 4.0 GW in NZ, showcasing the emphasis on hydrogen production in these regions under the NZEE scenario.

With this result for 2050, the NZEE scenario even exceeds the current master plan for the Northern Cape by 12 GW, thus confirming the validity of hydrogen and renewable ramp-up in this region. [23]

Table 30: Indicative pipeline route capacities and average flows by 2050 for the scenarios CP, NZ and NZEE and for the largest pipelines with a flow larger than 10t/h. to supply the sectoral demands.

	Capacity (GW)			Average flow (t/h)		
Pipeline route	**CP**	**NZ**	**NZEE**	**CP**	**NZ**	**NZEE**
H_2 pipeline Northern Cape → Free State	1.4	2.4	2.2	36	68.2	60.1
H_2 pipeline Free State → KwaZulu Natal	1.2	2.1	1.9	31.3	60.1	51.7
H_2 pipeline Mpumalanga → KwaZulu Natal	0.3	0.7	1.1	4.5	12.9	23.2
H_2 pipeline Northern Cape → Western Cape	0.7	1	0.9	18.4	27.1	15.3
H_2 pipeline Northern Cape → North West	2	1.4	1.6	39.2	36.7	13.2
H_2 pipeline North West → Gauteng	1.5	1	1.4	31	21.3	2

It should be noted that the spatial disaggregation of sectoral demand by region is simplified in the first cross-sectoral model version used here.

H_2 transport via pipelines

As part of the modelling, publicly available (limited) data on industrial plants, ports, airports, population and gross value added per region is used to distribute the exogenous demand for the PyPSA optimisation to the model regions. However, the PyPSA optimisation does not take into account any infrastructure for the transport of methane, liquid fuels, (liquified or gaseous) CO_2 feedstock or alternative transport options for hydrogen. In addition, the main scenarios do not restrict where power-to-liquid synthesis takes place. Therefore, the presented results on H_2 pipeline infrastructure are only to be interpreted as a first result. Further sensitivity analyses is advised and could reveal that the transport requirements are even higher or that H_2 electrolysis capacities need to be located closer to the demand and to the ammonia and PtL synthesis plants. However, the initial results for the cost-optimised spatial distribution of hydrogen by 2050 show that considerable pipeline capacities are required. In particular, the interregional export and import of hydrogen from the North Cape to the demand centres are recommended under the assumptions made.

In terms of total capacity, the Northern Cape is connected to Free State, North-West, and Western Cape with significant pipeline capacities across the scenarios. The Northern Cape to Free State route has one of the highest capacities, with 2.4 GW in NZ and 2.2 GW in NZEE, reflecting its role as a primary hydrogen transport pathway. The Free State to KwaZulu Natal route also shows substantial capacity, with 2.1 GW in NZ and 1.9 GW in NZEE, indicating the importance of hydrogen distribution to KwaZulu Natal. Additionally, the pipeline from Mpumalanga to KwaZulu Natal displays increasing capacity, reaching 1.1 GW in NZEE, which supports the distribution network toward KwaZulu Natal. The North West to Gauteng route, another notable connection, has capacities ranging from 1.0 GW in NZ to 1.4 GW in NZEE, underscoring Gauteng as a hydrogen recipient from surrounding regions.

Regarding average hydrogen flow, the pipelines from Northern Cape to Free State and from Free State to KwaZulu Natal are prominent across all scenarios. The Northern Cape to Free State pipeline achieves an average flow of 68.2 t/h in NZ and 60.1 t/h in NZEE, underscoring its role as a major artery for hydrogen transport. Similarly, the Free State to KwaZulu Natal pipeline records high flows, with 60.1 t/h in NZ and 51.7 t/h in NZEE, further supporting KwaZulu Natal as a key hydrogen destination. Other significant flows include the pipeline from Mpumalanga to KwaZulu Natal, which reaches 23.2 t/h in NZEE, indicating Mpumalanga's increasing role as a hydrogen supplier to KwaZulu Natal. Meanwhile, the North-West to Gauteng pipeline shows a reduced flow in NZEE at 2 t/h compared to 21.3 t/h in NZ, suggesting a shift in hydrogen distribution priorities in the NZEE scenario.

To contextualise the economic sense of those pipelines, the rule of thumb for the economic sense of pipelines formulated in the Hydrogen Valley report is referenced. In the report mentioned 500 km pipeline makes sense if 6.2 ton/h H_2 or more is transported. The estimated distances of the connections modelled range from 720 km to 150 km. For instance, the distance of hydrogen production in the Northern Cape to the centre of the Free State could be between 1000 km to 600 km and from the Free State to KwaZulu Natal 430 km. The distances are large. However, so are the flow rates described above and therefore the pipelines are cost-optimised under the assumptions made and also according to the Hydrogen Valley report's rule of thumb.

Further investigations must be carried out with regard to the topology and detailed routes. The modelled network is inaccurate. However, the cross-connection highlighted is also depicted in one of the pipeline plans in the Northern Cape masterplan (see [23]).

4.2 Sensitivity Analysis

The following section tests the impact of individual key parameters on the results of individual scenarios. The sensitivity of the results to individual parameters provides further insight for investment and planning decisions.

4.2.0 Test CO_2-target

Description

The CO_2 emissions limit for 2050 is derived based on South Africa's climate policy targets, adapted pathways from the Climate Action Tracker (CAT), and various national considerations. This limit plays a crucial role in shaping the energy system's pathway to net-zero, especially as CO_2 budgets and target values are significant constraints in system optimization. A key factor in this study is a target emissions trajectory that ends at 50 Mt CO_2 per year by 2050 for the main scenarios. As described in section 3.2.0, the CO_2 budget and the specific policy target value for fossil, energy, or sector-related CO_2 emissions in 2050 is still unclear or uncertain. Uncertainty factors include the development of LULUCF emissions, the trend in waste and agricultural emissions, and the options after 2050.

This sensitivity analysis explores the impact of lower and higher limits of 35 $MtCO_2$/year and 65 $MtCO_2$/year by 2050. These variations aim to assess the "last mile" reduction efforts needed and highlight potential risks of stranded assets from fossil-based investments as the energy system transitions. Green synthetic products are expected to cover liquid fuel and methane requirements in this sensitivity analysis. Thus, the analysis for this sensitivity focuses on 2050 and the comparison of NZ or NZEE with 35 $MtCO_2$/year and 65 $MtCO_2$/year. These variations aim to assess the "last mile" reduction efforts needed beyond 2050 and highlight potential risks of stranded assets from fossil-based investments. The results of interest are **liquid fuel and methane balance, CO_2 capture and usage, installed electricity and H_2 electrolysis capacity and system costs.**

Sensitivity Parameter

The sensitivity analysis is applied for the scenario NZ and NZEE and the assumptions for the year 2050. The CO_2 limit is decreased and increased from 50 $MtCO_2$/year to 35 $MtCO_2$/year and 65 $MtCO_2$/year. All other assumptions and parameters remain the same.

Results

Liquid fuels supply and demand

Figure 81, the balance of liquid fuel use, illustrates that with the lower CO_2 limit, **100% of the remaining liquid** fuel consumption for shipping, air transport, road transport and industrial road transport in South Africa (76 TWh) **must be covered by synthetic PtL fuels.** Thus, the total PtL fuels demand accommodates to **85 TWh or 6.9 Mt in NZ-35MtCO$_2$ and to 178 TWh or 14.4Mt in NZEE-35MtCO$_2$.**

The 6.9 Mt would correspond to the almost complete transformation of the Sasol Secunda [22] plant towards green Fischer-Tropsch fuels. The volume of PtL in the most ambitious scenario, NZEE-35Mt, would theoretically represent a 90% increase in Sasol Secunda's capacity, or a 47% increase over Sasol Secunda's and PetroSA's capacity, assuming that the Mossel Bay plant is reactivated. This raises the question of whether the export targets are feasible under these CO_2 restrictions.

With the higher CO_2 limit, however, no synthetic fuel is produced for the remaining consumption in South Africa. It should be noted that the scenario assumes a high level of electrification of consumption (see scenario section 3.5 and result section 4.1.0). The synthetic fuels totalling 10 TWh are produced for export.

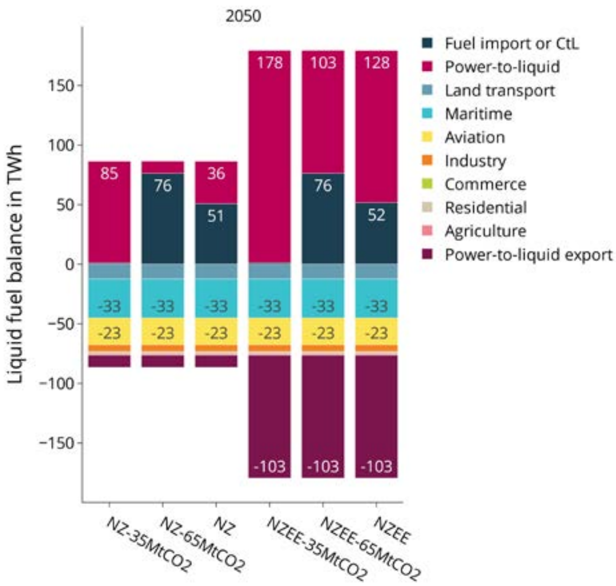


Figure 81: Liquid fuel balance with supply (+) and demand (-) for NZ, NZEE, and the sensitivities with higher or lower CO2 limit for 2050.

Methane supply and demand

The impact on the utilisation of fossil methane, shown in Figure 82, is also significant.

In the **NZ-35MtCO$_2$** scenario, methane use for electrification via gas turbines is drastically reduced, with the remaining **11 TWh** of gas demand in industry and commercial sectors covered by **synthetic green Power-to-Gas** (PtG). Conversely, the **NZ-65MtCO$_2$** scenario permits **25 TWh of fossil gas** imports to support both industrial processes and electricity generation.

Regarding the sensitivity runs for NZEE with varied CO_2 limits, the analysis shows that in NZEE-35MtCO$_2$, a higher ambition for emission reduction restricts the use of carbon capture and utilisation. As shown in the next section, a higher utilisation of direct air capture is preferred by the model. This is due to the capture rate of 90% for process emissions, which makes CCU less compatible with the restrictions of the sensitivity.

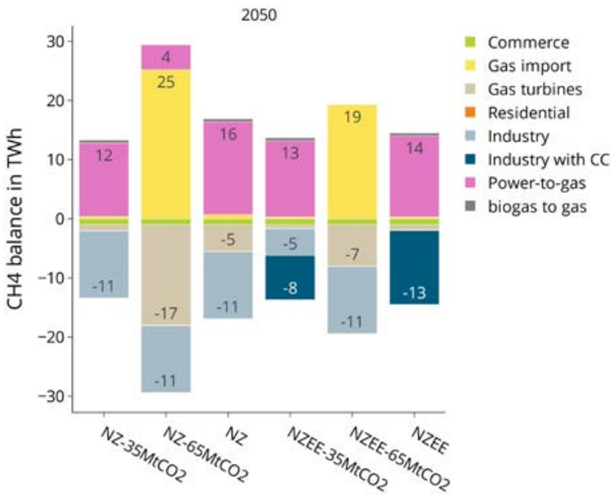


Figure 82: Methane (CH4) balance with supply (+) and demand (-) for NZ, NZEE, and the sensitivities with higher or lower CO2 limit for 2050.

As in NZ-65MtCO_2, synthetic methane is reserved for industry processes in **NZEE-35MtCO_2** and the standard NZEE scenario. However, **NZEE-65MtCO_2** allows limited fossil gas use for both industry and gas turbines, though at **levels 24% lower than in NZ-65MtCO_2.**

These findings underscore the substantial impact of the specified CO_2 emission limits on methane demand and fossil fuel reliance by 2050. Importantly, the results indicate that South Africa's reliance on gas imports will be limited in both scope and duration for ambitious reduction targets but are still used for slightly less ambitious targets. **This highlights the need for careful consideration in planning current and future gas infrastructure and plants**, ensuring alignment with long-term defossilisation goals. Clear and currently missing definitions of objectives and requirements for the energy or parts of the energy sector are essential for making informed decisions on pathways and minimizing the risk of stranded assets.

Carbon Capture and Usage

The relationship between all CCU technologies (Carbon Capture and Usage) and varying CO_2-reduction ambitions is shown in Figure 83. Under the **NZEE-65MtCO_2** target, the energy system primarily relies on carbon capture from process emissions and biomass, capturing a total of **26 MtCO_2 per year.** This capture volume is sufficient to meet the CCU demands for Power-to-Liquid (PtL) and Power-to-Gas (PtG) production without needing direct air capture. However, with the more ambitious **NZEE-35MtCO_2** target, the CO_2 demand for PtL and PtG increases by **62%**, requiring a total of **45.8 MtCO_2**. This scenario's stringent target introduces direct air capture (DAC) as a major source, providing 17.5 MtCO_2 per year to meet the higher CO_2 demand. Here, DAC is necessary despite being the most expensive option, highlighting its role as a last-resort technology to meet the lower CO_2 limit. The percentage increase in total CO_2 capture from NZEE-65MtCO_2 to NZEE-35MtCO_2 reflects the system's heightened reliance on various CCU sources to achieve deeper decarbonization. Process emissions remain the largest source across scenarios. At the same time, the need for DAC, chosen as the last option, underscores the cost and technical challenges associated with achieving more ambitious CO_2 reduction targets and levels of CO_2 feedstock usage.

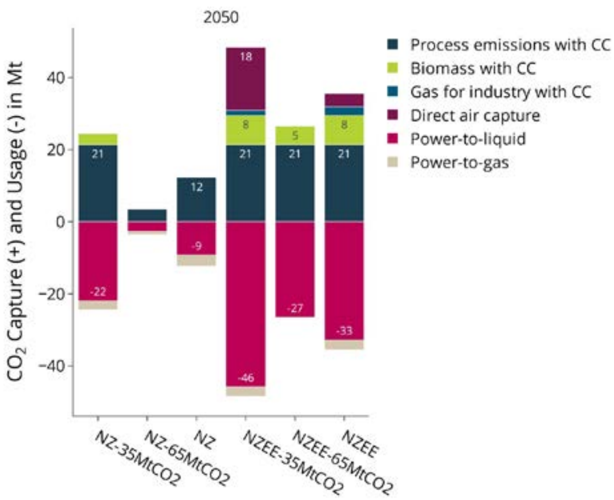


Figure 83: CO2 feedstock balance with capture volumes (+) and usage volumes (-) for NZ, NZEE, and the sensitivities with higher or lower CO2 limit for 2050.

However, decision-makers and further analyses should consider that regulatory guidelines of trade partners may prohibit the use of captured CO_2 from some of the sources used here and that investments in CCU could potentially become stranded assets, particularly given that not all CO_2 emissions can be fully captured. For instance, the current regulation of the EU for the use of emissions for RFNBOs (Renewable fuels of non-biological origin) requires that a carbon price, with a trajectory that is aligned with a carbon neutrality NDC of the country, is in place for the whole sector producing the RFNBO. Should, e.g., industrial CO_2 capture prove nonviable in the long-term [19], DAC would need to be utilised more extensively to meet the CO_2 feedstock requirements. Tracking the global regulatory framework and well-defined objectives is essential for making informed investment decisions and reducing the risk of stranded assets.

19 According to the current EU delegated act on the production of RDF, the use of CO_2 captured from fossil fuels in industrial processes is only allowed until 2040.

Installed capacities for electricity supply

The required installed capacities of wind and solar vary significantly in response to different CO_2 limits in the NZ and NZEE scenarios, emphasizing the impact of emissions targets on renewable needs for the additional production of PtL, PtG and feedstocks as shown in the previous figures. In the NZ-35MtCO_2 sensitivity run, the combined wind and solar capacity increases to 332 GW, representing an additional 28 GW (+9.2%) compared to the main NZ scenario (305 GW). This expansion underscores the need for greater renewable capacity to meet stricter CO_2 limits. By contrast, the NZ-65MtCO_2 scenario only requires 269 GW in total renewable capacity – 34 GW lower (or -11.1%) relative to NZ.

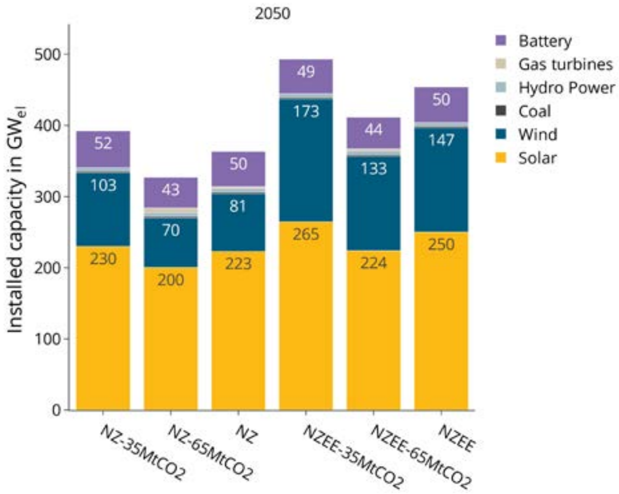


Figure 84: Installed capacities for electricity supply for NZ, NZEE, and the sensitivities with higher or lower CO2 limit for 2050.

The NZEE-35MtCO_2 scenario requires 436 GW of combined wind and solar capacity, an increase of 40 GW (+10.1%) over the main NZEE scenario (396 GW), aligning with the higher renewable output needed for deeper defossilisation. Conversely, the NZEE-65MtCO_2 scenario allows for a total capacity of 355 GW, 41 GW lower (-10.4%) than the standard NZEE. These findings illustrate that renewable capacity requirements expand significantly as CO_2 limits become more stringent in export-focused scenarios like NZEE. The differences in absolute numbers are more pronounced for NZEE than for NZ.

In terms of flexibility, the need for battery storage to balance intermittent wind and solar generation is slightly lower (around -17% lower) in the NZEE-65MtCO_2 scenario, which is associated with lower renewable capacity.

Installed hydrogen generation capacity

Figure 85 illustrates the installed hydrogen generation capacity in GWel for NZ, NZEE, and the sensitivities with higher or lower CO_2 limit for 2050. In the NZ-35MtCO_2 sensitivity scenario, the H_2 electrolysis capacity rises to 44 GW, which is 16 GW higher (+57.1%) than the main NZ scenario's capacity of 28 GW. This increase highlights the need for additional hydrogen production capacity to achieve more stringent CO_2 reduction targets. Conversely, the NZ-65MtCO_2 scenario requires only 17 GW of electrolysis capacity, 11 GW less (or -39.3%) than NZ.

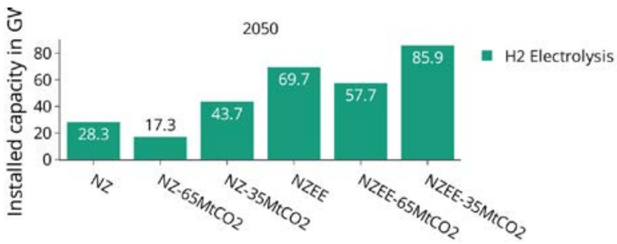


Figure 85: Installed hydrogen generation capacity in GWel for NZ, NZEE, and the sensitivities with higher or lower CO2 limit for 2050.

System expenses and revenues

The additional capacities required for achieving lower CO_2 emissions targets result in greater resilience for South Africa, reducing dependence on fossil fuel imports and gas price fluctuations, while enhancing export readiness against carbon border adjustment taxes. These pathways also represent a 'fair share'-contribution goal to global efforts for GHG emission reduction, which is most robust against uncertain GHG emission developments of e.g. negative emissions.

However, these benefits come with higher investment costs, as shown by the annualized expenditures for NZ and NZEE with varied CO_2 targets. In the NZ-35MtCO_2 scenario, annualized system expenditures reach 38.7 billion USD2023, marking an 8.7% increase over the main NZ scenario, which stands at 35.6 billion USD2023. Conversely, the NZ-65MtCO_2 scenario expenditures are 33.7 billion USD2023, which is a 5.3% decrease from the main NZ pathway. This discrepancy highlights the 'last mile' effort to reduce the last bit of emissions.[20]

In the NZEE sensitivity runs, the expenditure level is generally higher than NZ's, but the percentual difference is similar. The NZEE-35MtCO_2 pathway requires 55.8 billion USD2023 per year (+8.8% from NZEE). On the other hand, NZEE-65MtCO_2 the annual expenditures of 48.3 billion USD2023 represents 5.9% lower costs compared to NZEE. This comparison highlights the substantial investment costs tied to ambitious climate targets, especially for NZEE, where achieving deep emissions reductions with an export-oriented strategy demands greater capital.

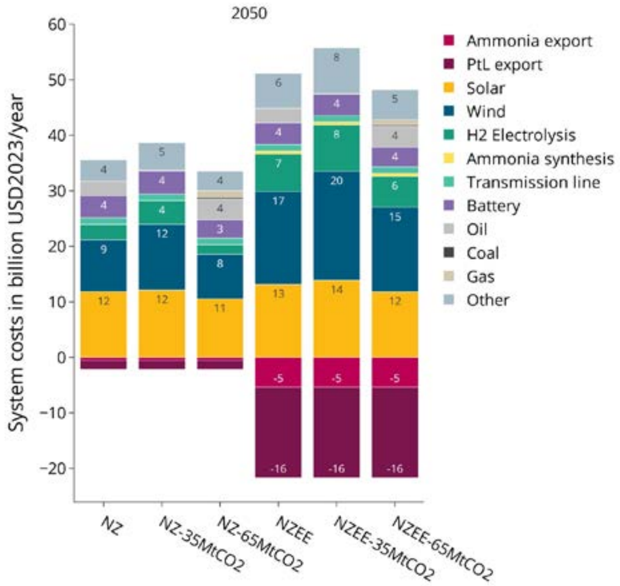


Figure 86: Annualised system expenses (+) and revenues via export (-) for NZ, NZEE, and the sensitivities with higher or lower CO2 limit for 2050 in USD2023 /year [20].

With export prices remaining constant across the model runs, the net system costs in 2050 are directly affected by the variations in annual system expenditures tied to the CO_2 limits, as displayed in the following table. Although the net system costs rise by up to 15.6%, they are still lower and almost equal to the net system costs of 34.4 billion USD2023/ year of the main CP scenario (see section 4.1.6).

Table 31: Net system costs for each sensitivity, along with the percentage difference compared to the main NZ and NZEE scenarios.

Scenario	Net System Cost 2050 (billion USD/year)	% Difference from Main Scenario
NZ	33.4	–
NZ-35MtCO_2	36.5	+9.30%
NZ-65MtCO_2	31.4	-6.00%
NZEE	29.5	–
NZEE-35MtCO_2	34.1	+15.60%
NZEE-65MtCO_2	26.6	-9.80%

20 The currency exchange rate between USD2023 and ZAR2023 is 18.4527

4.2.1 Test the Expansion Limit for the Transmission Lines

Description

In the main scenarios, the limit for grid transmission capacity expansion is held constant across scenarios to streamline the analysis and focus on the impact of the other drivers. However, previous studies focussing on the electricity system show that in addition to intra-regional and distribution grid expansion, transmission capacities between the regions of South Africa are crucial for a cost-minimised system and the integration of renewable energies [42]. These studies show that the marginal benefit decreases the higher the level of expansion. The interesting question is, therefore, what benefits an additional grid expansion has for South Africa in the context of a long-term climate-neutral energy system and the expansion and export of PtX.

This raises a critical question: what additional benefits could further interregional transmission capacity bring for South Africa, particularly in the context of achieving a climate-neutral energy system by 2050, supporting PtX expansion, and enabling energy exports? This sensitivity analysis, therefore, examines the impact of different transmission expansion levels specifically for the NZ and NZEE scenario in 2050, focusing on **system costs** and visualizing **transmission line expansions** in gigawatts across regions.

Sensitivity Parameter

The sensitivity analysis is applied for the scenarios NZ and NZEE and the assumptions for the year 2050. The parameter updated is the line volume expansion as a percentage of today's existing line volume. The sensitivity is labelled lv1.0 for 100%, lv1.1 for 110% and lv1.2 for 120% of the current line volumes.

Results

As displayed in Figure 87 expanding transmission line capacity leads to notable cost savings across both NZ and NZEE scenarios. In the NZ pathway, moving from **NZ-lv1.0 to NZ-lv1.1** (setting for the main scenario) reduces net system costs by **6.2%**, bringing costs down to 33.4 billion USD per year. Further expansion to **NZ-lv1.2** lowers costs by **7.3%**. The NZEE scenario shows even greater reductions, with **NZEE-lv1.1** cutting costs by **8.4%** to 29.5 billion USD per year and **NZEE-lv1.2** achieving a **10.6% decrease**. These results suggest that increased transmission capacity significantly reduces system costs, especially in the NZEE scenario, where greater interregional connectivity supports the balancing of large volumes of electricity supply and demand in space.

Furthermore, the results confirm that the marginal system cost advantage decreases. However, the impact of this driver is generally very significant. A cost reduction of 6.2 – 10.6% is relatively high in the context of a holistic energy system optimisation. The model can and does react to the limited grid expansion with all other optimisation variables, e.g. investment in batteries. With further restrictions, i.e. without optimising alternatives, the

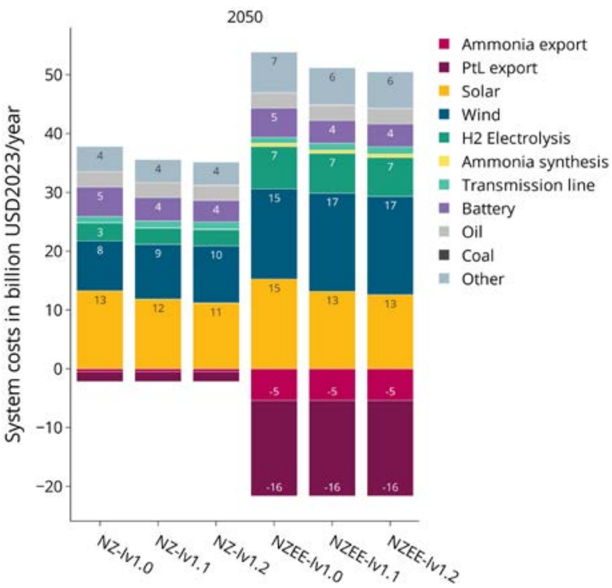


Figure 87: Annualised system expenses (+) and revenues via export (-) for NZEE and the sensitivities for line volume expansion 1.0, 1.1 and 1.2 in USD2023/year.

impact on system costs may be significantly higher in the real world with low transmission grid expansion.

As illustrated in the figure for system expenses and for installed electricity and hydrogen capacities, the increase of spatial flexibility leads to less installed r solar PV, batteries and electrolysers (greater utilization of these technologies).

Solar PV capacity in **NZ-lv1.0 is 251 GW**, which is **15.9% higher** than the **211 GW** in NZ-lv1.2. Battery capacity in **NZ-lv1.0 is 63 GW**, which is 28.6% higher than the 45 GW in NZ-lv1.2.

Likewise, the solar PV capacity in **NZEE-lv1.0 is 290 GW**, which is **17.6% higher** than the 239 GW in NZEE-lv1.2 and battery capacity in **NZEE-lv1.0 is 63 GW**, which is 22.2% higher than the **49 GW** in NZEE-lv1.2.

Regarding H_2 Electrolysis capacities, the utilisation of solar PV infeed with less electricity transmission results in **32 GW in NZ-lv1.0**, which is **10.3% higher** than the **29 GW** in NZ-lv1.2. For **NZEE-lv1.0, H_2 electrolysis capacity is 74 GW**, which is 8.1% higher than the **68 GW** in NZEE-lv1.2.

The view of the map for grid expansion (see Figure 90), shows which connections will be strengthened by 2050 and which capacities are built in which region in the modelled system for the most ambitious climate neutrality path NZEE with high exports.

In the **NZEE-lv1.2** scenario, certain transmission connections experience notable capacity expansions relative to their existing infrastructure. Next, the expansion above 2GW per connection is highlighted. The **Eastern Cape to Hydra Cluster** connection is expanded by **4.6 GW**, which represents a **56% increase** compared **8.2 GW**. Similarly, the **Free State to KwaZulu Natal** connection is expanded by **3.2 GW**, marking a 100% increase over its initial capacity of 3.2 GW. Finally, the **North-West to Northern Cape** connection expands by **2.2 GW**, which is a 55% increase over its estimated existing capacity of **4 GW**. These significant percentage increases indicate that strategic reinforcement of these transmission lines to facilitate renewable energy flow and interregional distribution is important to address key routes for balancing regional generation and demand across South Africa's energy grid.

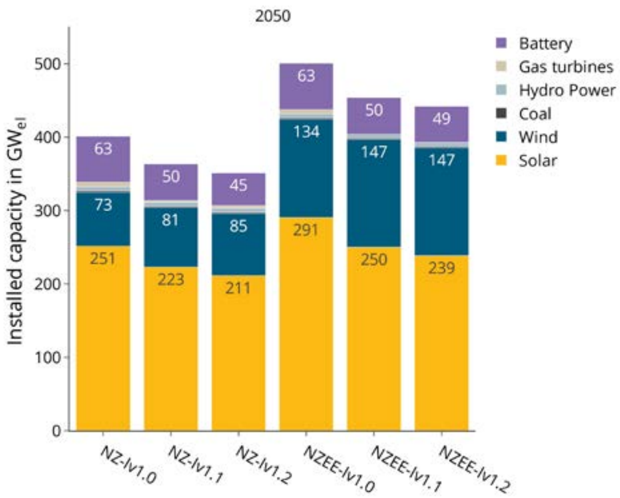


Figure 88: Installed capacities for electricity supply for the NZ and NZEE and the sensitivities lv1.0 to lv.1.2.

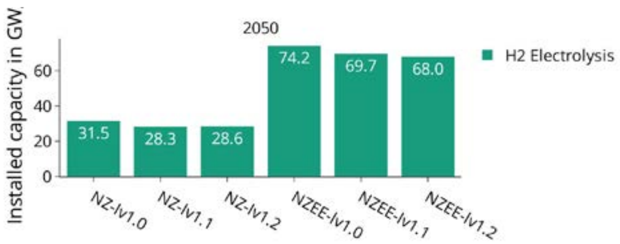


Figure 89: Installed hydrogen generation capacity in GWel for the scenarios NZ and NZEE and the sensitivities lv1.0 to lv.1.2.

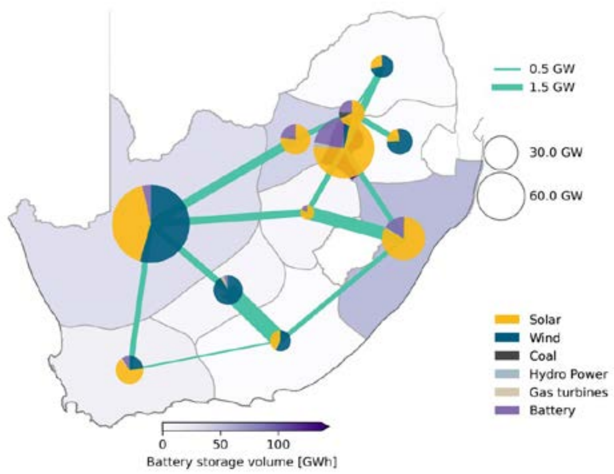


Figure 90: Map of expanded transmission grid, electricity generation, storage capacities by 2050 in the sensitivity NZEE-1.2 with a line volume expansion for the transmission lines of 120% compared to today's capacity.

The next figure displays the region-wise capacities without grid expansion. As illustrated in Figure 89, the case without transmission line expansion prefers higher solar and battery capacities to supply the electricity needs and support PtX production. The spatial analysis reveals that the **higher solar capacities** are seen in **Western Cape** (21 GW in NZEE-lv1.2 compared to 14 GW in NZEE-lv1.0), **KwaZulu Natal** (61 GW vs. 41 GW), **Gauteng** (94 GW vs. 70 GW), Mpumalanga (13 GW vs. 4 GW), and **Limpopo** (20 GW vs. 4 GW). To integrate solar generation, the battery capacity and storage volume are also higher in those regions. The installed wind capacities are lower, particularly in the Hydra Cluster.

The comparison of the spatial expansion of H_2 electrolysis capacities, storage and H_2 transport capacities in the case of high exports (Figure 92, Figure 93 and Table 32) reveals an overall higher and more concentrated expansion in NZEE-lv1.2. It should be emphasised in particular that H_2 electrolysers with a capacity of 6.6 GW are being built in KwaZulu Natal in the case of limited transmission grid expansion, and no capacities are built with high transmission capacities. Other regions, such as Gauteng and Western Cape, are also utilised more with limited line volumes. In contrast, with higher transmission line volume expansion, the H_2 electrolysis and storage capacities are more concentrated in the Northern Cape, Eastern Cape and Mpumalanga.

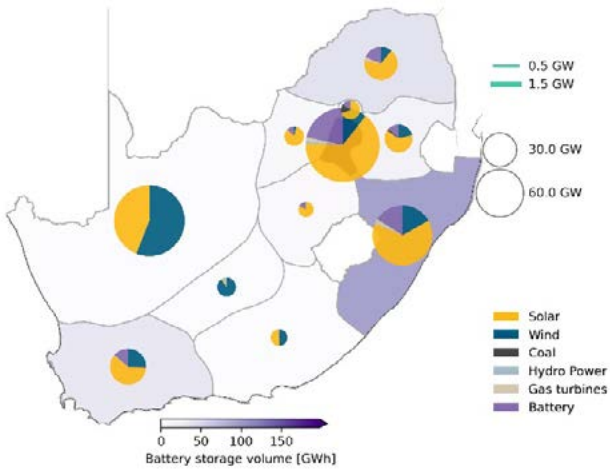


Figure 91: Map of expanded transmission grid, electricity generation, storage capacities by 2050 in the sensitivity NZEE-1.0 without a line volume expansion for the transmission lines (100% compared to today's capacity).

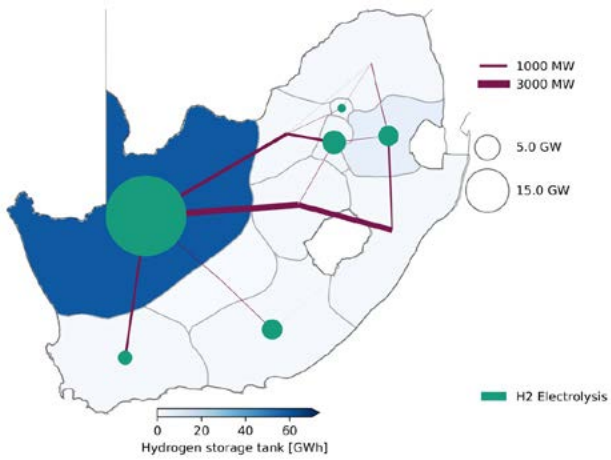


Figure 92: Map of installed hydrogen generation, storage and transport capacities by 2050 in the scenario NZEE-lv1.2.

Table 32: Region-wise H_2 Electrolysis capacity for NZEE-lv1.0 and NZEE-lv1.2 in GWel.

Region	NZEE-lv1.0 (GW)	NZEE-lv1.2 (GW)
Eastern Cape	1.4	3.5
Gauteng	11.2	4.6
KwaZulu Natal	6.6	0
Mpumalanga	2.5	3.5
Northern Cape	48.6	54.1
Pelly	0.8	0.6
Western Cape	3.2	1.7

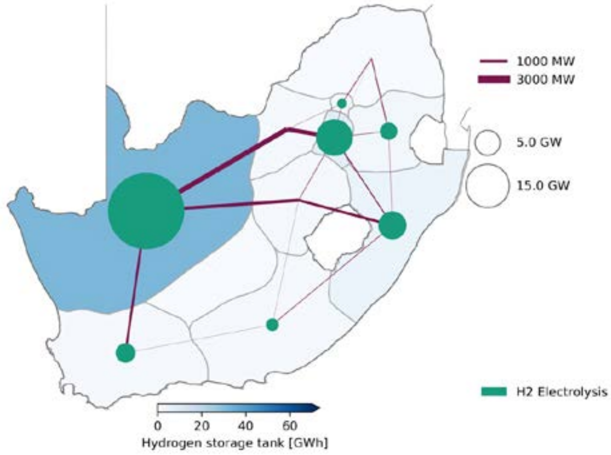


Figure 93: Map of installed hydrogen generation, storage and transport capacities by 2050 in the scenario NZEE-lv1.0.

In NZEE-lv1.2 more H_2 storage and electrolysis facilities are being built in the Northern Cape to maximise synergies of resources in the region and the H_2 transmission capacities from the Northern Cape to Free State (2.5, +92% higher than NZEE-lv1.0) and from Free State to KwaZulu Natal are higher (2.2, +100% higher than NZEE-lv1.0).

4.2.2 Test Higher Weighted Cost of Capital

Description

The future energy system in South Africa and worldwide will be dominated by investment and capital costs as opposed to today's variable fuel costs. The system costs of the energy system of the future are, therefore, significantly influenced by the average cost of capital (WACC) in addition to the specific investment costs. The WACC factor is the return on equity and debt capital. In general, it is influenced by various factors, including financial risks, business risks, market conditions and liquidity risks. These factors determine how high the costs of equity and debt capital are and how they are weighted. As a default value, 8.2% is defined for all scenarios. This WACC (discount rate) is taken from the IRP publication.

The sensitivity test is intended to determine the impact of a higher WACC value in the short term in 2030 and in the long term in 2050 for each of the three main scenarios. The results of interest are the **total system costs**, so the absolute and the relative differences between 8.2% and 11% WACC for these scenarios.

Sensitivity Parameter

The single sensitivity parameter WACC was varied twice for each of the three main scenarios and for the planning **years 2030 and 2050**. The default value of 8.2% is compared to **11%**. This WACC is applied and used for annualising all investment costs considered.

Results

The system expenses and revenues are visualised in Figure 94. The net system costs for the higher WACC are as follows. For the CP scenario, the bandwidth ranges from 33.09 in 2030 to 36.49 in 2050. The NZ scenario shows lower values, from 28.68 in 2030 to 32.88 in 2050, while the NZEE scenario ranges between 29.48 in 2030 and 29.13 in 2050. The minimum value across all scenarios for 2030 is 28.68 (NZ, 2030), and the maximum value is 36.49 (CP, 2050). The minimum value for 2050 is 29.12 (NZEE).

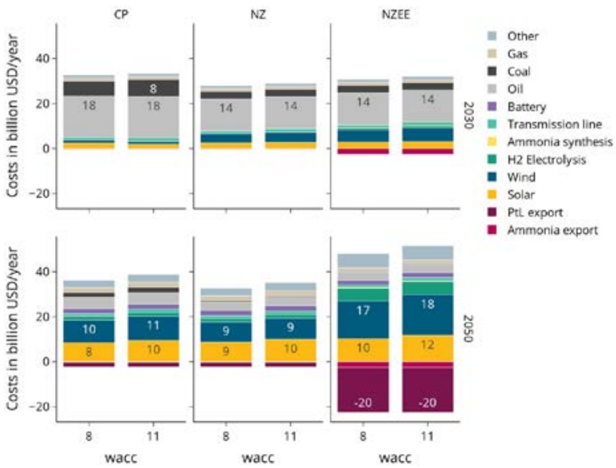


Figure 94: Annualised system expenses (+) and revenues via export (-) for a WACC of 8.2% and 11% for each the three main scenario CP, NZ and NZEE for the years 2030 and 2050.

This means that the total system costs for 2030 are 1.8% (CP, 2030), 3.6% (NZ, 2030), 4.2% (NZEE, 2030) higher and for 2050 the increases amount to 6.8% (CP, 2050), 7.3% (NZ, 2050) and 12.1% (NZEE, 2050).

In summary, with the assumptions made, the export scenario remains the most challenging in the long term, but also minimises costs overall. The energy-efficient NZ scenario would continue to minimise costs until 2030. However, the system cost advantages compared to the CP scenario decrease with a WACC of 11%.

Politically, it is important to stimulate the factors influencing the WACC. For instance, financial de-risking mechanisms, such as offtake guarantees, for investments in renewables and PtX are favourable and lower the WACC.

4.2.3 Test Wind Expansion Limit

Description

In recent years, the expansion of renewables in South Africa has been slower than the necessary annual expansion calculated in the main scenarios. The historical expansion shown at the beginning (see Figure 7) shows that wind expansion in particular is significantly slower than necessary for a cost-minimised path. The next sensitivity analysis will therefore analyse what impact a limited and reduced wind expansion would have on the system result.

Sensitivity Parameter

The parameter modified for this sensitivity analysis is the build limit for wind capacity expansion (excl. the existing capacities of 3.4 GW). The defined maximum build limit for capacity additions is 7.5 GW by 2030, 30 GW by 2040 and 6.25 GW by 2050. The underlying assumption for annual build rates are an increase from 500 MW/year for the next two years to +1500 MW/ year by 2030. The assumed annual build rate for the next decade increases from 2000 MW/ year to 2500 MW/year. For the final decade (2041 to 2050) the values are between 3000 MW/year and 3500 MW/year. The model runs for the sensitivity analysis are labelled with the suffix “GWC” (Global Wind Constraint).

Results

In comparison with the main scenarios (see section 4.1.1) the results of the sensitivity test show that the impact on CP is low for 2030, but very noticeable for NZ and NZEE. In the CP-GWC scenario for 2030, wind generation and solar generation is only slightly lower. In the scenarios NZ-GWC and NZEE-GWC, the share of wind generation is higher in the main scenarios. Due to the limitation the contribution of wind is 41% (NZ-GWC) to 60% (NZEE-GWC) lower in 2030. This also impacts the ratio between solar and wind generation which is around 3:2 in NZ-GWC and 2:1 in NZEE-GWC –

already by 2030. This differs from the developments in the main scenarios, in which the optimiser prefers the opposite or a balanced ratio for 2030 and 2050.

Consequently, the installed capacity for solar power is higher than in the main scenarios and the installed capacity for wind power is at its upper limit in each case. The next figure also shows that the **battery capacity in the NZEE-GWC scenarios is the highest in all years.** The role of the alternative peak load option, gas turbines using fossil or green methane, is similar to the main scenario and, therefore, rather small compared to the battery capacities.

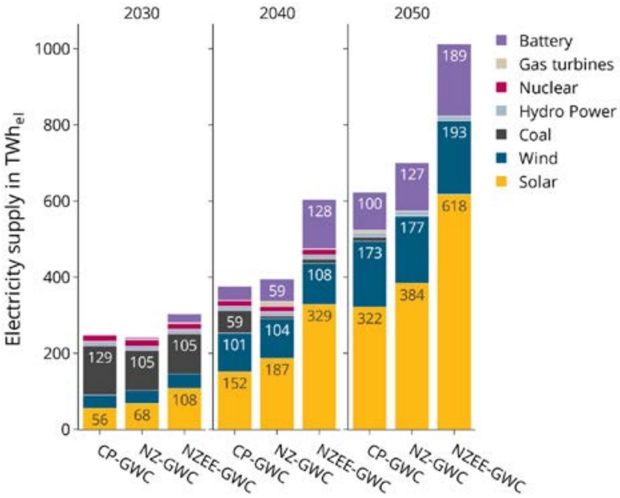


Figure 95: Electricity supply, and battery storage discharging for CP-GWC, NZ-GWC, and NZEE-GWC.

By 2030, solar capacity in NZ-GCW is 8.8 GW or 30% higher than in NZ. In NZEE-GCW, solar capacity almost doubles to 62 GW (+87%) compared to NZEE (33 GW). This shows that in the wind constrained case, solar is heavily relied upon to compensate for the limited wind capacity in 2030 if high exports are to be possible. The average annual build rate to reach 62GW by 2030, starting from 7.5GW of solar (utility-scale & embedded capacity) by the end of 2023, would hypothetically be 7.8GW/year. In 2040, the differences are similar to those in 2030. In 2050, the difference decreases because the model favours wind, which contributes more consistently to the grid, especially before 2050. In the CP-GWC and NZ-GWC, solar capacities reach 206 GW and 248 GW, respectively, which is 8 – 11% higher than in the main scenarios. **The NZEE-GWC case requires 381 GW of solar capacity, a significant difference of 131 GW or 52% compared to NZEE**.

The battery capacity required in the wind-constrained sensitivity scenarios (GWC) is notably higher than in the main scenarios, highlighting the correlation of the system's reliance on storage solutions when wind capacity expansion is limited. In the NZ-GWC, battery capacity is 27 GW in 2040. Which equates 16.1 GW or 153% higher capacity compared to NZ. For NZEE, the **battery capacity in 2040** is 17 GW, but in NZEE-GWC, it is significantly higher at **59 GW (+252%). By 2050** the absolute differences range between **5 GW to 45 GW or from 13% to 89% (NZEE-GWC)**. In this model, the high solar shares and limited wind are balanced with increased battery storage. Future studies should consider how collaboration with neighbouring countries like Namibia and Mozambique, could reduce storage needs by balancing renewable feed-in over a wider area.

In comparing the net system costs of the wind-constrained scenarios (GWC) with the main scenarios, we observe only minor differences, reflecting the system's adaptability (without further constraints) to the limited wind capacity. For 2030, the relative differences range from no difference in CP to 1 and 3.8% in NZ-GWC and NZEE-GWC. For 2050, only the export-oriented pathway is impacted significantly with 10.5% higher net system costs due to significantly higher investment expenses for solar PV investments, battery capacities, H_2 electrolysis.

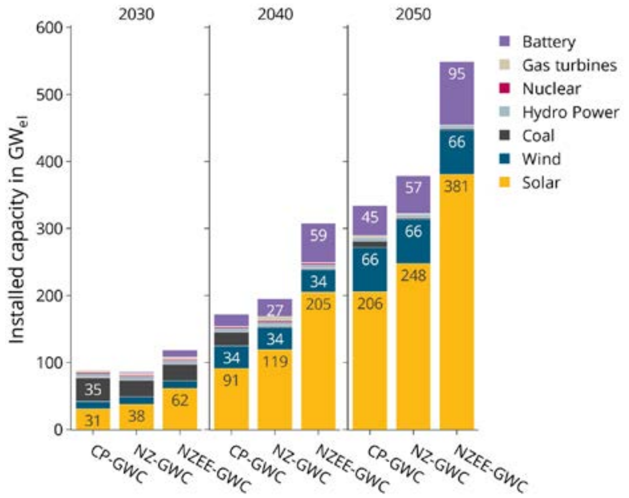


Figure 96: Installed capacities for electricity supply in CP-GWC, NZ-GWC and NZEE-GWC.

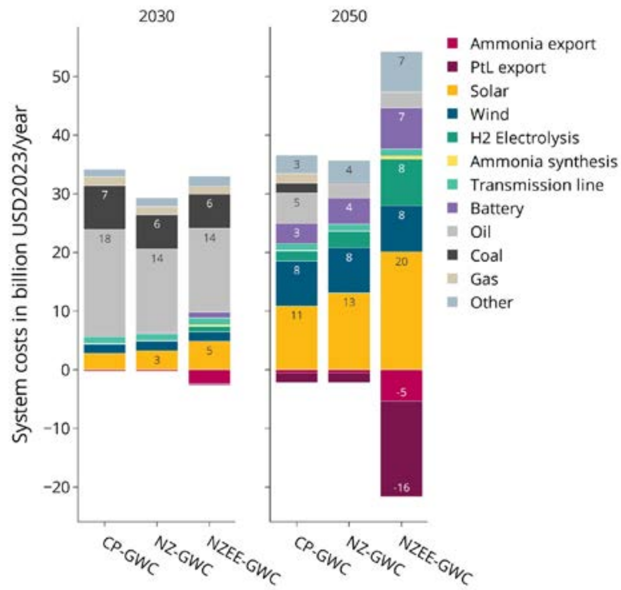


Figure 97: Annualised system expenses (+) and revenues via export (-) for CP-GWC, NZ-GWC, and NZEE-GWC in USD2023.

Table 33: Net system costs for each 2030, 2050 and for the sensitivity scenarios CP-GWC, NZ-GWC, NZEE-GWC.

Year	Scenario	Net System Cost 2050 (billion USD/year)
2030	CP-GWC	33.9
	NZ-GWC	29.1
	NZEE-GWC	30.4
2050	CP-GWC	34.4
	NZ-GWC	33.5
	NZEE-GWC	32.6
	NZEE-GWC	32.6

Key conclusions

- The sensitivities, especially NZ-GWC and NZEE-GWC, show a significant increase in solar generation and capacity to compensate for the forced limited expansion of wind power. Solar capacity requirements are 30% (NZ-GWC) to 87% (NZEE-GWC) higher than the main scenario by 2030 and up to 52% (NZEE-GWC) higher by 2050. Battery capacities are also notably higher by 2040 and beyond, as the system compensates for reduced wind generation with increased reliance on solar and storage.

- The net system costs in wind-constrained scenarios remain close to the main scenarios, with modest increases across all scenarios in 2030. However, by 2050, the high and early export pathway (NZEE-GWC) incurs a significant 10.5% of annualised net system cost increase by 2050, largely due to a suboptimal mix of solar and wind and additional investments needed in solar PV, battery storage, and hydrogen electrolysis.
- Higher solar PV and battery storage capacities offset the limited wind in this model, but future analyses should explore collaboration with neighbouring countries like Namibia and Mozambique to help balance renewable energy input across a larger area, potentially reducing storage requirements.
- Furthermore, the results showed that methane-fuelled gas turbines or fuel cells (an option in the model, but not chosen) are too expensive based on the assumptions made. The option of hydrogen-powered gas turbines, with all corresponding challenges, should also be analysed in the future and might be a valuable addition to the power plant park.

The previous sections 4.1 and 4.2 present the demand per energy and commodities market and per sector. In the following, the different potential PtX product demands per sector for the scenarios NZ (Net-Zero), NZEE (Early Export Net-Zero) and the sensitivity with only 35MtCO_2 energy system-wide emissions are listed and discussed in more detail to provide an overview. The ranges are based on the results and assumptions of the scenarios, which inherit a lot from the data set of the Just Energy Transition Plan scenarios and the existing political strategies for transport and industry (see also section 3.5). The scenario-based approach distinguishes this overview from maximum potential calculations, which might provide different (higher) numbers for specific sub-sectors. The values are expressed in hydrogen, considering the conversion factors of the respective synthesis process.

4.3 Sectoral Allocation of Green PtX Fuels and Feedstocks

Table 34: Range of demand for PtX fuels and feedstocks across NZ and NZEE sensitivity runs for 2050 expressed in hydrogen.

Sector and subsector	GH_2 (TWh)
Transport	52 – 90
• Aviation	• 15 – 30
• Shipping	• 24 – 47
• Freight road	• 13
• Passenger road	• 0 – 16
Industry (excl. extra Export)	45 – 62
• Iron & Steel	• 13
• Ammonia	• 11
• Cement, Non-metallic	• 5 – 13
• Mining	• 2 – 9
• Chemicals & Others	• 14 – 16
Electricity	• 0 – 6
Export	20 – 193
• Green Ammonia	• 6 – 58
• Green Power-to-liquid	• 14 – 135
Total	117 – 351
Total w/o Export	97 – 158

In the transport sector, green hydrogen demand is driven by applications in heavy-duty vehicles as well as international and domestic aviation and shipping. The transport sector's total green hydrogen equivalent demand ranges between 52 – 90 $TWhH_2$ or 1.2 – 2.7 MtH_2. Heavy-duty vehicle demand for freight transport is estimated to be 13 $TWhH_2$ with fuelling stations for the mobility corridors N1, N2 and N3. For international and domestic aviation, the demand ranges from 15 – 30 $TWhH_2$, and for shipping, it spans 24 – 47 $TWhH_2$. The range represents the uncertainty regarding the CO_2 emission level for the energy system or for the international shipping and aviation sectors. The international sectors highly depend on the development of international regulation implemented by the International Civil Aviation Organization (ICAO) and the International Maritime Organization (IMO). Around 75% of the aviation demand is for international aviation and below 1% of the shipping demand is for domestic shipping (according to [89]). The major airports, where the majority of demand is expected, are the OR Tambo, the Cape Town and the King Shaka International Airports. The net-zero scenarios for aviation and maritime transport assume that demand will remain constant until 2050. If demand increases significantly but CO_2 limits remain the same, the hydrogen requirement for PtX fuels for air and sea transport would be correspondingly higher. As an estimate: the demand for air traffic increases to 47 TWhoil in the CP scenario, which corresponds to approx. 62 $TWhH_2$.

The industrial sector accounts for a significant proportion of South Africa's hydrogen demand by 2050 (45 – 62 $TWhH_2$) in both the NZ and NZEE scenarios, driven by efforts to implement green industry. The iron and steel industry, traditionally reliant on coal-based processes (BF BOF, coke oven), shifts towards hydrogen as a reducing agent in Direct Reduced Iron (DRI) production. This process, coupled with Electric Arc Furnaces (EAFs), allows for low-carbon and green steel manufacturing by replacing carbon-intensive inputs with hydrogen. Hydrogen-based DRI-EAF systems become a cornerstone of around 6 Mt of green steel production by 2050. As stated during one of the stakeholder workshops (see appendix), plans to phase out of the three BF (blast furnace) plants currently in operation exist. The existing but mothballed DRI plant in Saldanha of ArcelorMittal South Africa (AMSA) – with a capacity of around 0.8 Mt of DRI – plans to revive its operation and ramp up production.

Ammonia production is another major consumer of hydrogen (up to 11 TWh), particularly for green fertiliser manufacturing. In a conventional process, hydrogen is produced from natural gas, but in the NZ and NZEE pathways, it is sourced from H_2 Electrolysis powered by renewables. This green ammonia synthesis enables the agricultural sector in Southern Africa to move away from fossil fuels.

The cement industry in South Africa is regionally fragmented and perceived as a “closed shop” business. Today the industry consumes biomass, coal, electricity and natural gas. The scenarios see the need to transition to PtX for providing the high temperature heat and reagent material for cement production in the NZ and NZEE scenarios in the range of 5 $TWhH_2$ to potentially 13 $TWhH_2$. An association that could coordinate the transition of the cement industry is the Concrete Manufacturer Association (CMA).

The chemicals subsector (without the refinery sector), including synthetic fuels and speciality chemicals, incorporates hydrogen and hydrogen derivatives into various synthesis processes and, to a very limited extent, for process heating. The total consumption of the industries allocated to the chemical sector in this study and in the data set from the Energy System Research Group of the University of Cape Town is 8 TWh. It should be noted that this doesn’t include the large-scale intermediate output of the refinery sector. The secondary demands of the refinery or Power-to-liquid sector are allocated to PtL fuel export or the transport sectors in the table. Other industry branches like aluminium or Pulp & Paper might need further PtX fuels for process heating.

For the mining and PGM sectors, a high degree of electrification of transport for mining (mining trucks) and process heat and a shift away from coal is assumed. The remaining or new utilisation of hydrogen, methane and liquid fuels results in a PtX consumption in hydrogen of 2 – 9 TWh. While fuel cells or Dimethylether are also being discussed, battery electric solutions for mining trucks appear to be the medium-term solution that large companies are investing in. A recent $2.8 billion agreement between Fortescue Metals Group and Liebherr exemplifies this shift on a global scale. Fortescue, the world’s fourth-largest iron ore miner, purchased 475 electric-powered mining machines to replace two-thirds of its mining fleet in Australia [113].

According to the optimisation model, the usage of PtX fuels for re-electrification is extremely limited, given the high level of electricity consumption by 2050. This is due to the relatively high capacity factors of renewables compared to the capacity factors of renewables in other countries and the equalisation of feed-in across the spatial area and via the electricity grid. If the transmission and distribution grid of the ESKOM National Transmission Company South Africa does not function robustly in the future, higher balancing feed-ins from PtG-powered gas turbines would be necessary.

The potentially largest driver for PtX fuels and feedstock demands is PtX export. Under our assumptions, in line with previous studies, the hydrogen volumes needed for taking the targeted export opportunity range from 19.3 – 193 $TWhH_2$ per year. In the case of high exports relatively early on, the early export revenues would enable a further ramp-up of exports. However, this requires a number of political measures, and there are currently political hurdles (see next chapter) for large-scale implementation by companies such as Sasol, Hive, Enertrag, Navitas, Linde and others.

5 Conclusion, Recommendations and Future Research

The model- and scenario-based analysis in this study contributes to the assessment of South Africa's energy system pathways under different levels of policy stringency and market development. This study developed the first multi-sector, multi-regional and hourly resolved model for South Africa. While the results are based on an innovative approach, it is important to note that the quantitative results of this study depend on the assumptions made for the years 2030 to 2050 in different scenarios and sensitivity settings. The main scenarios defined and analysed are the Current Policy [21] (CP), the Net-Zero (NZ) and the Net-Zero Early Export (NZEE) scenarios. The exogenous assumptions for the final energy demands of these scenarios largely follow existing policy or strategic objectives and inherit a lot from the Just Energy Transition Plan. The scenario results should not be understood as forecasts with probabilities but as optimisation results subject to boundary conditions and a set of techno-economic assumptions. In this sense, the analysis provides a comprehensive framework for stakeholders to assess required investments, policy needs, and technological innovations required to steer the country towards a sustainable energy future. The most important conclusions from the model-based analysis and recommendations for action follow.

South Africa's energy landscape needs to be prepared for a 2.6x to 4.3x times increase in electricity consumption compared to 2022 on the way to an efficient, climate-neutral system.

Electricity demand increases by a factor of 2.6 to 4 across all scenarios compared to 2022. The increase in electricity consumption is due to direct and indirect (via PtX) electrification for various end uses. The electricity load of today's industry sectors will double by 2050. New electric vehicles will lead to an electricity consumption of 59 to 64 TWh by 2050. Cooling, heating, cooking and other applications in the residential sector will continue to be electrified (+30% from 2030 to 2050).

The green PtX fuels and feedstock economy consumes 95 to 406 TWh of electricity in the three main scenarios by 2050. In 2050, the consumption of H_2 electrolysis at 406 TWh is 4.3 times as high as in CP. The share of electricity consumption of H_2 electrolysis is 50% of the net electricity consumption of 817 TWh (without battery) in the ambitious net-zero and export scenario NZEE.

An unprecedented roll-out of wind and solar power capacities is key for both least-cost supply of increased electricity demands and for unlocking the development of green PtX production.

In all scenarios analysed, wind and solar energy confirm their status as cornerstones of the supply of South Africa's growing future electricity demand. At minimum in 2050, the total capacities of wind and solar are around 6.7x times higher than the installed coal power capacity of 2023 (39 GW) [12] and at maximum 10x times higher.

---

21 The CP scenario follows the planned coal phase-out path and assumes a more inefficient future energy system. However, the CP scenario does not limit the nation-wide expansion of wind or solar PV.

In terms of the ratio of solar to wind generation, the optimisation model recommends a solar to wind generation mix of around 2:3 to 2.5:3 (solar to wind) in NZ and NZEE before 2050, shifting to 3:2 in 2050. This mix is chosen by the model based on CAPEX and the need to curtail renewables. This mix balances the variability of volatile generation over time and space as much as possible. The higher solar shares in NZ and NZEE in 2050 indicate that solar is the cheapest source of electricity and can be well integrated with H_2 electrolysis and smart charging of electric vehicles as they become available in large numbers. Prior to 2050, the emphasis will need to be on procuring wind and solar with the above shares.

In terms of total renewable capacity, NZ and NZEE require 9 to 21 GW more capacity by 2030 than CP (41 GW), and NZEE surpasses NZ with an additional 92 GW by 2050 (30% more than NZ). These substantial installations will require significant grid upgrades to connect and integrate the increased capacity.

To achieve the optimal capacity targets by 2050 in the scenarios focussing on domestic demands (CP, NZ), the average annual build rate for wind ranges from 1.1 – 3.6 GW/year among periods and from 3.1 – 14.4 GW/year for solar PV. The expansion of solar PV has to increase significantly for the period 2040 to 2050. The highest wind power build rates are observed for the period 2030 – 2040. If South Africa aims to capitalize on high export opportunities, the required per anno expansion for wind increases to 3.8 (+52% to NZ), 6.0 (+67% to NZ) and 5.6 GW (+133%). The annual solar build rate is significantly higher (7.8GW/year, +56%) from 2030 –2040 but similar to NZ otherwise. These build rates far exceed current national plans, emphasizing the need to incorporate export potential and the results of least-cost optimisations into future energy planning.

	CP	NZ	NZEE	CP	NZ	NZEE	CP	NZ	NZ
	2023-2030			2030-2040			2040-2050		
Wind (GW/yr)	1.1	2.5	3.8	4.7	3.6	6.0	1.6	2.4	5
Solar (GW/yr)	3.2	3.1	3.5	3.5	5.0	7.8	12.4	14.4	14

Figure 98: Average annual wind and solar build rates required for the periods 2023 – 2030, 2030 – 2040 and 2040 – 2050 for each of the scenarios.

In comparison to the latest plans, such as the IRP 2023 Draft, the results highlight the significance of NZEE and this PtX-focused study for political and industrial decision-makers and for planning the expansion and investment needs for grid and pipeline infrastructure. It indicates that a rapid expansion of renewable energy, far beyond most existing plans, is necessary to satisfy the projected domestic demands and facilitate early exports.

Substantial battery capacities, as well as moderate gas turbine and LNG import capacities are required to integrate renewable energies and to meet the sectoral methane demands – latter, however, only for a limited time frame.

Given the scenario setting (e.g. no Vehicle-to-Grid) and the model's scope, large scale battery capacities are needed latest by 2040 with 4 – 16 GW, going up to 46 – 50 GW by 2050. Batteries help to integrate solar and wind power generation and to reliably supply the electricity consumption of all sectors. This presents an opportunity for embedding value chains, which has been explored in the South African Renewable Energy Masterplan. Localised manufacture of battery components can be supported by a repurposing of the 12I tax incentive for Greentech manufacturing. [13]

By 2040, between 5 and 10 GW of gas turbines will be built in all scenarios, mainly as backup capacity for peak loads rather than for baseload supply. This raises concerns about the financial viability of this new capacity. It is recommended, as does the Energy Council [14], to promote dispatchable capacity for system stability where (imperfect) market signals alone would not be sufficient to ensure bankable projects.

The total gas consumption of all sectors is at around 40 TWh by 2030 in all scenarios and peaks at 45 TWh by 2040 in the NZ scenario. However, by 2050, natural gas is replaced by synthetic green Power-to-Gas in the main NZ and NZEE scenarios. The gas consumption of our analysis is low compared to other studies, such as the NBI study. The NBI study expects a temporary consumption of 94 TWh in 2040 (around 50 TWh more) [15]. The use of gas for gas-fired power plants depends on the assumed electricity consumption, gas import prices, ramp-up of renewables, and availability of the transmission grid, etc. However, based on the findings and from a national perspective, the currently planned LNG import capacity in Richards Bay of 5 million tonnes (or 77 TWh) is needed. With regard to the technical and economic feasibility of a new fossil gas import and pipeline infrastructure, the time-limited utilisation of gas in the NZ and NZEE scenarios is a challenge. Supply contracts and any planning should be limited to a time frame of 20-25 years, taking into account a net-zero pathway. Furthermore, the switch to synthetic gas should be planned from today onwards.

With regard to PtX, the scenario and sensitivity analysis show that under the emission reduction targets defined for the default net-zero scenarios, synthetic methane is seen as necessary by the model. However, the need and the timing for synthetic and green PtG to meet certain emission levels by 2050 or beyond apparently depends on system-wide or sector-specific CO_2 targets. The slightly higher CO_2 emission level for NZ or NZEE, assuming negative LULUCF emissions and a different fair share budget, reveals that natural gas import shrinks to 16 TWh but is still present. Clarity regarding sector-specific CO_2 targets for 2050 is needed to facilitate planning.

Increased support for the accelerated expansion and integration of renewable energies and battery storage is necessary.

Recently, progress has been made regarding the reformation of the electricity market and the implementation of policy support for renewables, as tracked in the recent progress report of the Energy Action Plan by NECOM [16]. Examples of progress include the removal of the licensing threshold for private power generation, the establishment of a one-stop energy shop to facilitate permits and the initial establishment of a national transmission company (ESKOM NTCSA). These activities should be continued and improved. To further support and accelerate the expansion of solar, wind and batteries the following actions are recommended:

- Fast-track public procurement processes for renewable energy sources (RES) and battery energy storage (BES) to meet NZ and NZEE targets before a functioning electricity market is established, particularly through streamlined approvals and financing support.
- Establish a competitive electricity market and address potential market failure due to market power or hurdles to participate in the market.
- Use auctions and other incentives for renewable projects, such as tax incentives, to encourage capacity expansions in specific zones with available grid capacity.
- Promoting private investment in generation capacity by informing on the removal of the licensing threshold and improving the fast-tracking of approvals in a one-stop shop, which was established in June 2023.
- Improve grid connection capacity in the Cape regions to support the connection of the renewable energy procurement programme's capacities.
- Extension of the programme for controlling the demand for distribution, taking into account electrolysers and battery-electric vehicles.
- Implement the framework of a national wheeling framework to enable the non-discriminatory usage of the transmission grid. Many will benefit from this, including PtX projects.

South Africa's potential in terms of suitable land area and resources is enormous, but major investments to strengthen the power grid's connection capacity in the Cape regions, the transmission grid and H_2 transport capacities are crucial to integrate the Tier 1 renewable regions and unlock competitive PtX production.

For this study, suitable areas with good conditions for renewable energies were identified and hourly generation profiles for wind and solar energy were created using spatio-temporal data sets. The result of this analysis of the area potential shows that the area potential for the construction of solar and wind energy plants is enormous, depending on the region, and far exceeds demand. The identified areas overlap with the Renewable Energy Development Zones (REDZs), but additional well-suited areas are seen in all regions. The REDZs could, therefore, be expanded in coordination with the TDP process. The weighted mean full load hours (FLH) per supply region ranges from 1584 h in

KwaZulu Natal to 1898 h in the Northern Cape for solar PV. The weighted mean FLH per supply region ranges from 2268 h in KwaZulu Natal to 3561 h in the Hydra Cluster model region for wind. It should be noted that at a smaller scale, weather conditions could be even better, up to a FLH of around 1950 for solar PV and 4400 for wind.

However, the areas suitable for solar PV and wind are also constrained by the power grid. The latest two Generation Connection Capacity Assessment (GCCA) show that there is little or no capacity for additional capacity in the Cape regions. Furthermore, interregional transmission line capacity to the Northern Cape is limited. The latest Transmission Development Plan (TDP)[22] addresses the problem of a lack of grid infrastructure (substations). In this study, we limit the expansion of the Cape regions in the CP and NZ scenarios based on the plans in the TDP. For NZEE the generation capacity expansion in the Cape regions is not restricted, assuming accelerated investments in grid infrastructure or partly stand-alone PtX systems that are independent of the grid. In addition, in all scenarios the interregional transmission capacities are also modelled.

The model and scenario results show that the Cape regions are significantly expanded – most in the NZEE scenario, in which the capacities go beyond the current plans in the TDP. The sensitivity runs to test the impact of inter-regional transmission networks show that no network expansion would result in 10% higher energy system costs compared to a 20% expansion relative to current transmission capacity. Figure 99 highlights the line improvements recommended by the model. Important expansions include the connections from the North Cape region to the demand centres in order to exploit the exceptional renewable capacities in the region.

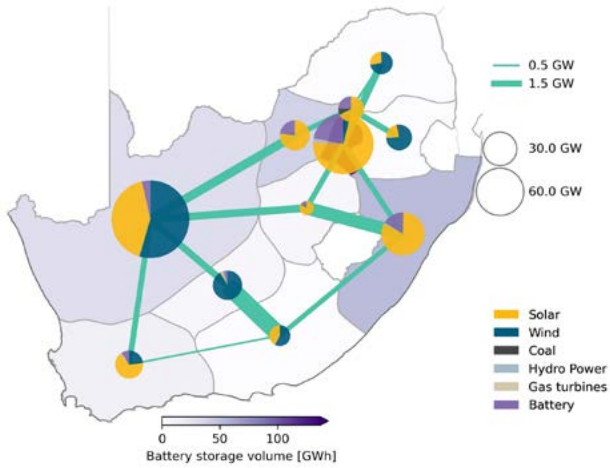


Figure 99: Map of the expanded transmission grid, electricity generation, and storage capacities by 2050 in the sensitivity NZEE-1.2 with a line volume expansion for the transmission lines of 120% compared to today's capacity.

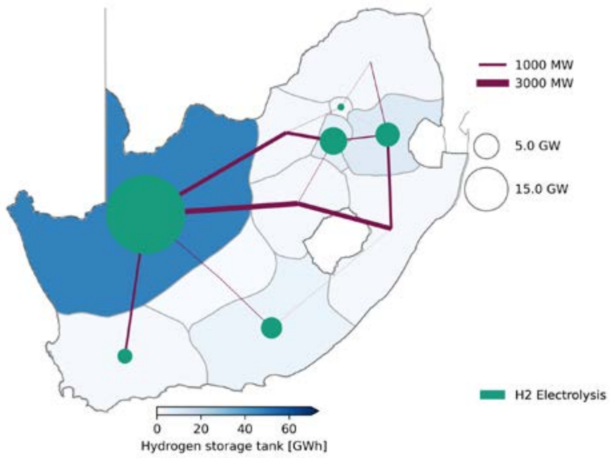


Figure 100: Map of installed hydrogen generation, storage and transport capacities by 2050 in the scenario NZEE.

Therefore, the grid infrastructure in the Cape region urgently needs to be improved. Furthermore, it is recommended that the research groups of the next TDP and of ESKOM take potential Power-to-X developments into account.

The expansion of the electricity grid infrastructure should be coordinated with the planning of other transport infrastructures for the other energy carriers and the new PtX fuels and feedstocks. With PyPSA-RSA-Sec, we have made a first move towards an integrated cross-sector and cross-infrastructure planning and are analysing not only electricity transmission capacities but also the necessary H_2 transport capacities. The model results show that transport capacities for H_2 are expanded and co-optimised. As illustrated in the next Figure, the Northern Cape, Gauteng, and Mpumalanga dominate with large H_2 Electrolysis capacities.

22 Transmission capacity refers to the maximum amount of electricity that can be transported across the grid's transmission lines across regions, while generation connection capacity indicates the maximum amount of electricity that power plants can feed into the distribution grid. The generation connection capacity depends on the capabilities of the power plants, their connection agreements with the grid operator and the available substation capacities. While transmission capacity focuses on the grid's ability to carry power, generation connection capacity deals with how much power can be produced and injected into the grid.

According to the optimising of the model, this results in a need for H_2 transport from the Northern Cape to the industrial and densely populated regions of Gauteng and KwaZulu Natal to supply the assumed final energy hydrogen demands (e.g. for chemical industry or heavy-duty FCEV). Although the distances for H_2 pipelines are very large (e.g. Northern Cape to Free State is approx. 600 – 1000 km), the volumes with an average flow of more than 60 t/h would justify the economic viability.

A dedicated analysis and roadmap for hydrogen transport via pipeline, rail, or road from production sites to demand centres or synfuel facilities is highly recommended. This should be developed in close collaboration with Transnet, the key pipeline and rail infrastructure provider. It is recommended that relevant stakeholders participate in "Transnet Long Term Planning Framework" [17].

As South Africa and the world move towards Net-Zero emissions, the total demand of PtX fuels and feedstocks in South Africa of 3.5 – 10.5 Mt is driven by industry, international aviation and shipping, freight transport and the PtX export opportunity.

The demand for green PtX in the transport sector is driven by international aviation, shipping, and heavy-duty vehicles. Projected PtX demands range between 52 and 90 $TWhH_2$ by 2050, with key infrastructure needed along mobility corridors (N1, N2, and N3) and at the international airports of OR Tambo, Cape Town and King Shaka International. The high variation in demand is due to uncertainties in international regulatory developments for aviation and shipping, which are largely influenced by the International Civil Aviation Organization (ICAO) and the International Maritime Organization (IMO).

The industrial sector, particularly iron and steel, ammonia, cement, and chemicals, is a major consumer of green hydrogen and PtX, with projected demands reaching 45 to 62 $TWhH_2$ by 2050. It is assumed that the Iron and steel production via DRI-EAF processes using hydrogen as a reducing agent will ramp up by reviving the mothballed assets of ASMA in Saldanha, while green ammonia supports the production of fertilizer for use in Southern Africa.

PtX exports represent the largest potential driver for hydrogen demand, with potentially up to 193 $TWhH_2$ or 5.8 MtH_2 needed by 2050. Companies like Sasol, Hive, Enertrag, and the Prieska consortium are interested in large-scale production in the Northern Cape, Western Cape, Mpumalanga (Secunda) or at Sasolburg. Early export activities by the actors mentioned and by others would catalyse further capacity expansions and export growth, though these would require substantial policy support to overcome existing regulatory and financial hurdles and risks.

28 to 70 GW of H_2 electrolysis, plus large capacities for synthesis processes and CO_2 capture, will be required to produce the volumes of PtX for domestic use and export by 2050.

The installed hydrogen generation capacity reaches 0.5 to 0.6 GWel in the scenarios CP and NZ in 2030. It increases to 9.1 GWel by 2040 and 17.2 to 28.3 GWel (65% higher in NZ than CP) by 2050. In the NZEE scenario, the ramp-up of hydrogen capacity is much more ambitious. By 2030, NZEE achieves 5.8 GWel of installed capacity. This capacity increases drastically to 30.6 GWel in 2040 and more than doubles by 2050, reaching 69.7 GWel. The installed hydrogen capacities in 2040 and 2050 are 3.4 to 2.5 times higher than in NZ.

The NZEE scenario requires a substantial ramp-up of hydrogen electrolysis capacity. This is coupled with the need for infrastructure, supportive policies and significant expansion in renewable capacity (396 GW in total). With the hydrogen production levels for domestic use and for export, NZEE is in line with the ambitions of the GHCS uplift scenario and the NBI net-zero study for South Africa.

Green Power-to-Liquid (PtL) fuel synthesis starts to scale significantly after 2030, mainly to meet export demands. By 2040, PtL exports reach 4.5 TWh in both CP and NZ, while NZEE targets an ambitious 45 TWh. By 2050, these export volumes increase further, with CP and NZ at 10 TWh and NZEE reaching 100 TWh (or 8.3MtFT), highlighting NZEE's emphasis on establishing South Africa as a major PtL exporter in global markets. NZ and NZEE scenarios incorporate additional green PtL production to meet CO_2 constraints, with 26 TWh allocated to supply green fuels for aviation and shipping by 2050, representing an e-fuel share of 50%.

By 2050, the NZEE scenario demands extensive CO_2 capture – 21 $MtCO_2$ from industrial processes, with additional capture from biomass and direct air sources – driven by high PtL and PtG fuel production needs.

To meet hydrogen electrolysis needs, desalination requirements rise across scenarios, with NZEE reaching 172.7 million m^3 by 2050 – over four times the CP demand. This substantial water use reflects NZEE's ambitious hydrogen and export targets but remains significantly below the historical water consumption of coal-fired power plants.

While the net-zero and the least-cost export-oriented net-zero paths for the energy system in South Africa exploit the industrial and natural potential to the highest degree, these paths also involve the highest investments, challenges and risks that need to be addressed.

Under the assumptions made, the pathways of NZ and NZEE result in the lowest net system costs per year, considering annualised capital expenditure, operating expenditure and export revenue.

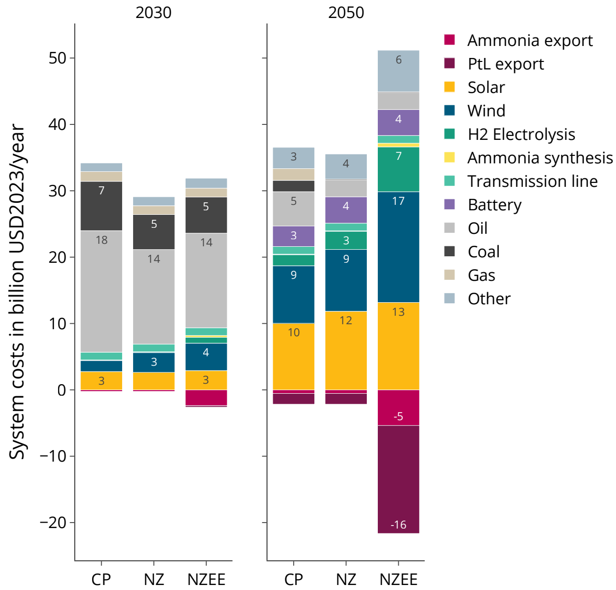


Figure 101: Annualised system expenses (+) and revenues via export (-) for CP, NZ, and NZEE in USD2023 [23].

The energy system evolves from a fuel-dominated cost structure in 2030, reliant on oil and coal, to a CAPEX-intensive structure by 2050, with significant investments in wind, solar, and H_2 electrolysis technologies. By 2050, total system expenses in NZEE reach 51.2 billion USD – higher than CP and NZ – offset by export revenues of 21.6 billion USD from ammonia and PtL fuels, showcasing the revenue potential of large-scale hydrogen exports.

Due to these high export revenues, NZEE becomes the most cost-effective scenario by 2050, despite being slightly more expensive in 2030. The difference between 2030 and 2050 indicates that the higher proportion of higher-quality PtL fuel exports is more profitable for South Africa than ammonia exports. Under our price and global PtX market assumptions, the competition in the ammonia export market is high making it hard for South Africa to compete by 2030. Conversely, the competitive advantage of South Africa in the PtL export market is significant. Two significant advantages are (1) the available Carbon Capture and Usage options beyond the cost-intensive Direct Air Capture technology, which are not available for non-industry heavy exporters and (2) the available expertise and facilities for the Fischer-Tropsch synthesis of fuels, which were taken into account here by reducing technology costs. Further geographical advantages are a long coastline for seawater desalination and existing global shipping routes from the ports in South Africa.[23]

Beyond the net system cost advantages of the ambitious net-zero scenarios (NZ and NZEE), the high-level estimation of job effects also shows higher job creation potential in the renewable sector in the range of 184 to 215 thousand jobs per year, and lower relative energy generation costs. The expansion and development of a large seawater desalination industry will provide bonus effects for the local population – without relevant additional costs compared to the costs of H_2 production or the energy system.

Despite the arguments in favour of NZEE, several risks and challenges beyond the already mentioned capacity expansion requirements exist and must be addressed. Other infrastructure challenges relate to the scenario's reliance on new export infrastructure such as the planned Boegoebaai port, the need to improve basic infrastructure such as roads in these new industrial regions, and the associated uncertainties about construction times of those infrastructure projects.

23 The currency exchange rate between USD2023 and ZAR2023 is 18.4527

As mentioned, many sources for capturing and using CO_2 (CCU) positions South Africa competitively in the global PtX market. With regard to these by-products, it will be important to keep an eye on the development of the regulatory framework in South Africa and with trading partners in the future.

Concrete recommendations regarding CCU are:

- In order to achieve the ambitious export targets which are possible by 2040, early planning must be a priority for CCU infrastructure as well as carbon transportation pipelines, which should be built during the 2030s.
- Negotiations with the EU to amend the RED & DA on the free allocation of electrons should also be prioritised to allow e-SAF produced at a transitioning Secunda site to be eligible under the RFNBO regulations.
- An international book and claim system for e-SAF would enable the use of the fuel produced at secunda to enter the global aviation market with minimal need for transportation.

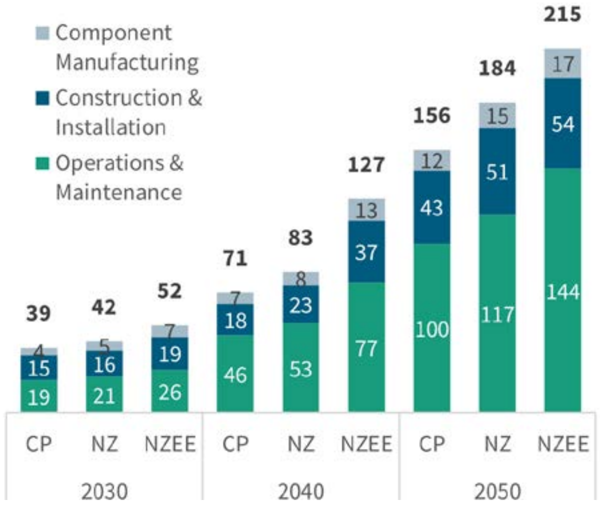


Figure 102: Indicative estimation of potential job creation effect in thousand jobs per year (kjobs/year) for operation and maintenance, construction and installation and component manufacturing for each time horizon and scenario.

Clarity on South Africa's 2050 net-zero target and global targets for international shipping and aviation is important to avoid stranded investments and socio-economic problems.

South Africa submitted its updated Nationally Determined Contribution (NDC) for 2030 in September 2021 [92]. The communicated conditional target range for greenhouse gas emissions is 350 – 420 $MtCO_2e$ by 2030 incl. negative LULUCF or an estimated 366 – 436 excl. LULUCF according to Climate Transparency [93]. In addition to the NDC target range for 2030, the President has communicated the commitment to net-zero by 2050 and recently signed the Climate Change Bill into law. This lays the foundations for ambitious long-term CO_2 reductions. However, the CO_2 budget and the specific policy target value for fossil, energy or sector-related CO_2 emissions in 2050 are still unclear or uncertain. Uncertainty factors include the development of LULUCF emissions, the trend in waste and agricultural emissions and the options after 2050.

This study explores the impact of lower and higher limits of 50 $MtCO_2$/year, namely 35 $MtCO_2$/year and 65 $MtCO_2$/year by 2050 via a sensitivity analyses. These variations aim to assess the "last mile" reduction efforts needed and highlight potential risks of stranded assets from fossil-based investments as the energy system transitions.

The results of the sensitivity analysis show, that lower CO_2 targets (35 $MtCO_2$) significantly increase renewable energy capacity needs, driving additional wind and solar installations in both NZ and NZEE scenarios. For instance, NZ-35$MtCO_2$ demands 332 GW, a 9.2% increase over the main NZ scenario, while NZEE-35$MtCO_2$ needs 436 GW, marking a 10.1% rise above NZEE. Hydrogen electrolysis capacity similarly scales, reaching 44 GW in NZ-35$MtCO_2$ – over 57% higher than the main NZ scenario. Conversely, a relaxed CO_2 target (65 $MtCO_2$) reduces these needs, with NZ requiring only 269 GW of renewables and 17 GW for hydrogen, demonstrating the direct influence of CO_2 targets on capacity planning.

Tighter CO_2 targets (35 $MtCO_2$) drive complete reliance on synthetic fuels for remaining liquid fuel consumption, especially for sectors like shipping and aviation. In NZEE-35$MtCO_2$, synthetic Power-to-Liquid (PtL) demand for export reaches 178 TWh, almost doubling capacity at facilities like Sasol Secunda. In contrast, with a 65 $MtCO_2$ limit, fossil fuel imports persist, covering residual demand for industrial processes and electricity, highlighting the shift from fossil dependence to synthetic fuels as emission targets tighten.

Achieving lower CO_2 emissions results in higher annualized expenditures, underscoring the cost of final emission reductions. For instance, NZ-35MtCO_2 incurs annualized costs of 38.7 billion USD2023 (+8.7% over NZ), while NZEE-35MtCO_2 reaches 55.8 billion USD2023 (+8.8% over NZEE). Despite these costs, stricter targets enhance South Africa's resilience, reducing fossil fuel import dependence, stabilizing against price fluctuations, and positioning the country to capitalize on green exports under international carbon standards.

Therefore, it is recommended to support future research on a clear definition of sectoral CO_2 targets for 2050.

While green industrialisation in South Africa will increase the competitiveness of the economy in climate-compatible markets, supportive policies are needed to leverage the potential.

The decarbonisation of industry and the PtX fuels and feedstocks required for this are no longer necessary only for a net-zero path in South Africa, but for the development of a sustainable economy. The so-called green industrialisation can enhance South Africa's economic resilience in climate-compatible markets by boosting its competitive edge in green technologies and value chains.

This aligns with South Africa's Just Transition Framework, which prioritises sustainable industry development and the gradual shift from carbon-intensive production. However, support is essential in order to take full advantage of these opportunities. Policies for an inclusive and successful transition are described in a comprehensive policy brief by Trade & Industrial Policy Strategies [18], as well as the strategies (SAREM [19], Just Energy Transition Plan [20], Hydrogen Society Roadmap for South Africa [21]) already mentioned. The recommendations are:

To build a robust local supply chain, policies should incentivize domestic manufacturing of renewable and green hydrogen components, as proposed in the South African Renewable Energy Masterplan (SAREM). Additionally, workforce development through Technical Vocational Education and Training (TVET) colleges and the Sector Education and Training Authorities (SETAs) should focus on emerging technical roles, such as renewable energy technicians and GH_2 specialists, to equip South Africans with skills for a green economy.

Key policy recommendations to support the green industrialisation, as also described in [18], are:

- Establish a green public procurement policy prioritizing local, sustainable products, such as renewable energy components, electric vehicles, and sustainable building materials, to stimulate domestic green industries.
- Introduce dedicated incentives for manufacturers adopting green processes or producing green technologies, including preferential financing and tax benefits for companies contributing to the renewable energy, battery, and electric vehicle sectors. An example of the support of local manufacturing is the tax incentive 12I for Greentech, proposed by the South African Renewable Energy Masterplan to build domestic value chains for energy storage technology.
- Establish or improve designated green industrial zones with specialized infrastructure, tax incentives, and streamlined regulatory processes.
- Gradually phase out fossil fuel subsidies and reallocate these funds toward green industrial policy tools, including tax incentives for renewable energy projects and concessional loans for green technology development.
- Increase funding for R&D in renewable energy, battery storage, and green hydrogen production. Establish partnerships with the private sector to support the commercialization of green innovations.

Promote the development of interlinked roadmaps for national energy and Power-to-X planning.

To effectively plan the national energy generation, transmission and Power-to-X (PtX) fuels and feedstock developments, it is essential to establish a comprehensive, interlinked strategy and policy roadmap that integrates strategies for electricity generation, transmission, and related infrastructure. This roadmap should include key elements for PtX value chains, recognizing their cross-cutting impact on land, water, energy, natural resources, logistics, and finance. Coordinated efforts among various government departments, public sector institutions, and private sector stakeholders are essential for a seamless value chain.

The roadmap should align and interlink existing plans such as the Grid Connection Capacity Assessment (GCCA), Transmission Development Plan (TDP), and the Integrated Resource Plan (IRP) with hydrogen-focused strategies like the Green Hydrogen Commercialisation Strategy. This integration will ensure a cohesive approach to grid and transport infrastructure development, supporting both hydrogen projects and the broader renewable energy transition in South Africa.

Track global developments and continuously update roadmaps.

The PtX market, PtX and hydrogen market regulation, auction designs and the development of green technologies are currently subject to high dynamics. For instance, the report describes the cost dynamics of H_2 electrolysers, solar and wind. Furthermore, it is outlined that the Export price assumptions are uncertain. It is also unclear when the global demand pull for PtX will happen. Against this background, it is necessary to continuously track global developments and update the relevant roadmaps.

Future research is needed to dive deeper into details on transport routes and infrastructure, potential synergies between neighbouring countries in SADC, different sectoral demand developments, and further aspects.

- Higher spatial resolution (more than 11 regions) combined with improved representation of transporting routes and infrastructure for transporting hydrogen, methane, liquified fuels, water, ammonia, CO_2, biomass water, ammonia, CO_2, biomass.
- Improve the representation of technology constraints, such as the selectivity of the Fischer-Tropsch process or unit commitment constraints on a regional level.
- Extend the analysis of the targeted production of PtX export products to other PtX products such as, for example, green DRI.
- Analysis of the potential of cooperation between SADC countries using a multi-national model for the SADC regions.
- Focus on short-term time horizon with predictive assumptions on the market ramp-up of renewables and power-to-X projects.
- Assessment of further transport and industry demand sector developments (nationally and region-specific).
- A detailed socio-economic assessment .
- Integrate PtX scenarios and roadmaps into the next Transmission Development Plan.
- Update and adapt South African Hydrogen roadmaps on a regular basis.
- Facilitate further research and sensitivity analysis by promoting open energy data and open-source models.
- Detailed energy system analysis should become a key pillar of future strategies.

References

[1] Eskom, Eskom Data Portal. [Online]. Available: https://www.eskom.co.za/dataportal/

[2] Minister of Finance, Republic of South Africa, ESKOM DEBT RELIEF BILL. [Online]. Available: https://www.treasury.gov.za/legislation/bills/2023/%5BB5-2023%5D%20(Eskom%20Debt%20Relief).pdf

[3] South African Petroleum Industry Association, „Petroleum Industry Quarterly Review: 2024 Q1: Key Performance indicators for the South African petroleum industry," FTI Consulting, 2024. Accessed: 15-Oct-24. [Online]. Available: https://fuelsindustry.org.za/wp-content/uploads/2024/04/FTI-Consulting_SAPIA-Quarterly-Report-2024-Q1-1.pdf

[4] Reuters, „Cost of South Africa's first LNG import terminal pegged at $372 mln-plus," Reuters, 14-Feb-24, 14-Feb-24. https://energy.economictimes.indiatimes.com/news/oil-and-gas/cost-of-south-africas-first-lng-import-terminal-pegged-at-372-mln-plus/107688690 (accessed: 15-Oct-24).

[5] CSIR, „Statistics of utility-scale power generation in South Africa in 2022," 2023. [Online]. Available: https://www.csir.co.za/sites/default/files/Documents/Statistics%20of%20power%20in%20SA%20 2022-CSIR-%5BFINAL%5D.pdf

[6] Crippa M. et al., „CO_2 emissions of all world countries: JRC/IEA/PBL 2022 Report," EDGARv7, Luxembourg, 2022. [Online]. Available: https://edgar.jrc.ec.europa.eu/report_2022

[7] Hydrogen Council, McKinsey, Global Hydrogen Flows: Hydrogen trade as a key enabler for efficient decarbonization.

[8] Hydrogen Council, McKinsey, Global Hydrogen Flows - 2023 Update: Considerations for evolving global hydrogen trade.

[9] International Renewable Energy Agency (IRENA), Global hydrogen trade to meet the 1.5°C climate goal: Trade outlook for 2050 and way forward.

[10] Department of Trade, Industry and Competition, Republic of South Africa, Green Hydrogen Commercialisation Strategy for South Africa: Final Report. [Online]. Available: https://www.thedtic.gov.za/green-hydrogen-commercialisation-strategy/

[11] Department of Science and Innovation, Republic of South Africa, South Africa Hydrogen Valley Final Report. [Online]. Available: https://www.dst.gov.za/images/2021/Hydrogen_Valley_Feasibility_Study_Report_Final_Version.pdf

[12] CRSES | The Centre for Renewable and Sustainable Energy Studies, SA Energy Made Visual - CRSES | The Centre for Renewable and Sustainable Energy Studies. [Online]. Available: https://www.crses.sun.ac.za/sa-energy-stats/#solar-pv-capacity (accessed: 04-Nov-24).

[13] 2024 South African Renewable Energy Grid Survey reveals 48GW of Wind Energy Projects in the pipeline, a substantial 60% growth welcomed by the industry | South Africa Wind Energy Association. [Online]. Available: https://sawea.org.za/news/2024-south-african-renewable-energy-grid-survey-reveals-48gw-wind-energy-projects-pipeline (accessed: 28-Oct-24).

[14] T. Creamer, Energy council calls for overhaul of public IPP procurement model. [Online]. Available: https://www.engineeringnews.co.za/article/energy-council-calls-for-overhaul-of-public-ipp-procurement-model-2024-11-13 (accessed: 14-Nov-24).

[15] NBI, BCG, BUSA, South Africas Net-Zero Transition. [Online]. Available: https://www.nbi.org.za/report/south-africas-net-zero-transition/

[16] NECOM, „Energy Action Plan: 18 Month Progress Report: March 2024," Republic of South Africa, 2024. [Online]. Available: https://www.stateofthenation.gov.za/assets/downloads/Update_EnergyActionPlan_18Months.pdf

[17] Business With Us Transnet Long Term Planning Framework. [Online]. Available: https://www.transnet.net/BusinessWithUs/pages/ltpf.aspx (accessed: 14-Nov-24).

[18] Trade & Industrial Policy Strategies, A policy primer for green industrialisation in South Africa: Policy Brief 8/2024.

[19] Executive Oversight Committee, „South African Renewable Energy Masterplan (SAREM): An inclusive industrial development plan for the renewable energy and storage value chains by 2030," 2023.

[20] The Presidential Climate Commission, South Africa's Just Energy Transition Plan (JET IP): For the initial period 2023-2027.

[21] Department of Science and Innovation, Republic of South Africa, Hydrogen Society Roadmap for South Africa 2021. [Online]. Available: https://www.dst.gov.za/images/South_African_Hydrogen_Society RoadmapV1.pdf

[22] Sasol Limited, Sasol Business Overview Document. [Online]. Available: https://www.sasol.com/sites/default/files/2022-06/Sasol%20Business%20Overview%20Document.pdf (accessed: 07-Nov-24).

[23] NCEDA, Northern Cape Green Hydrogen Masterplan: A catalyst for socio-economic development. [Online]. Available: https://www.ncgh2.co.za/

[24] IEA - International Energy Agency, „Global Hydrogen Review 2023,"

[25] Eskom, Transmission Development Plan 2023–2032.

[26] Department of Mineral Resources and Energy, Integrated Resource Plan (IRP2019).

[27] Department of Mineral Resources and Energy, „Integrated Resource Plan 2023: Draft," 2024. [Online]. Available: https://www.dmre.gov.za/mining-minerals-energy-policy-development/integrated-resource-plan/irp-2023

[28] Meridian Economics, Review of the IRP 2023. [Online]. Available: https://meridianeconomics.co.za/wp-content/uploads/2024/03/IRP2023-Modelling-Submission-20240318.0.pdf

[29] Eskom National Transmission Company South Africa, Generation Connection Capacity Assessment: Website. [Online]. Available: https://www.ntcsa.co.za/gcca/

[30] Eskom, „Transmission Generation Connection Capacity Assessment of the 2024 Transmission Network (GCCA - 2024): 2024," 2022.

[31] Department of Transport, South Africa, „Green Transport Strategy for South Africa: (2018-2050)," 2018.

[32] Department of Energy, South Africa, „Draft Post-2015 National Energy Efficiency Strategy," 2016.

[33] B. Merven and Tatham J., „Demand Projection Model in Support of IRP Update 2023," 2023. [Online]. Available: https://www.dmre.gov.za/mining-minerals-energy-policy-development/integrated-resource-plan/irp-2023

[34] Eskom, „Integrated Report," 2023. [Online]. Available: https://www.eskom.co.za/wp-content/uploads/2023/10/Eskom_integrated_report_2023.pdf

[35] Meridian Economics, „Comparative Analysis of IRP 2023 cost assumptions," 2024. [Online]. Available: https://meridianeconomics.co.za/our-publications/comparative-analysis-of-irp-2023-cost-assumptions-2/

[36] IEA and International Energy Agency, „Net Zero Roadmap: A Global Pathway to Keep the 1.5 °C Goal in Reach - 2023 Update," [Online]. Available: https://iea.blob.core.windows.net/assets/9a698da4-4002-4e53-8ef3-631d8971bf84/NetZeroRoadmap_AGlobalPathwaytoKeepthe1.5CGoalinReach-2023Update.pdf

[37] IEA - International Energy Agency, „Global Hydrogen Review 2023," [Online]. Available: https://iea.blob.core.windows.net/assets/ecdfc3bb-d212-4a4c-9ff7-6ce5b1e19cef/GlobalHydrogenReview2023.pdf

[38] Maritime Safety Information, World Port Index. [Online]. Available: https://msi.nga.mil/Publications/WPI

[39] Hersbach, H., Bell, B., Berrisford, P., Biavati, G., Horányi, A., Muñoz Sabater, J., Nicolas, J., Peubey, C., Radu, R., Rozum, I., Schepers, D., Simmons, A., Soci, C., Dee, D., Thépaut, J-N., „ERA5 hourly data on single levels from 1940 to present.: Copernicus Climate Change Service (C3S) Climate Data Store (CDS)," 2023.

[40] PyPSA-RSA Github Repository: PyPSA Model of the South African Energy System. [Online]. Available: https://github.com/MeridianEconomics/pypsa-rsa

[41] PyPSA-ZA Documentation: PyPSA-ZA: An open Optimisation Model of the South African Power System. [Online]. Available: https://pypsa-za.readthedocs.io/en/latest/index.html

[42] J. Hörsch and J. Calitz, „PyPSA-ZA: Investment and operation co-optimization of integrating wind and solar in South Africa at high spatial and temporal detail," 30-Oct-17. [Online]. Available: http://arxiv.org/pdf/1710.11199v1

[43] Hazem Abdel-Khalek, Leon Schumm, Eddy Jalbout, Maximilian Parzen, Caspar Schauß, and Davide Fioriti, „Sector-coupled PyPSA-Earth, a global open-source multi-energy system model," [Online]. Available: https://ssrn.com/abstract=4743242

[44] F. Neumann, E. Zeyen, M. Victoria, and T. Brown, „The potential role of a hydrogen network in Europe," Joule, vol. 7, no. 8, pp. 1793–1817, 2023, doi: 10.1016/j.joule.2023.06.016.

[45] PyPSA Documentation: PyPSA: Python for Power System Analysis. [Online]. Available: https://pypsa.readthedocs.io/

[46] T. Brown, J. Hörsch, and D. Schlachtberger, „PyPSA: Python for Power System Analysis," Journal of Open Research Software, vol. 6, no. 3, p. 12, 2018, doi: 10.5334/jors.188.

[47] M. Parzen et al., „PyPSA-Earth. A New Global Open Energy System Optimization Model Demonstrated in Africa," Sep. 2022. Accessed: Sep. 14 2022. [Online]. Available: https://arxiv.org/pdf/2209.04663.pdf

[48] A. Hughes and et al., „Evolution, Assumptions and Architecture of the South African Energy Systems Model SATIM," 2020.

[49] M. Pfennig et al., „Global GIS-based potential analysis and cost assessment of Power-to-X fuels in 2050," Applied Energy, vol. 347, p. 121289, 2023, doi: 10.1016/j.apenergy.2023.121289.

[50] E. Vartiainen et al., „True Cost of Solar Hydrogen," Solar RRL, vol. 6, no. 5, p. 2100487, 2022, doi: 10.1002/solr.202100487.

[51] Prognos, Kosten und Transformationspfade für strombasierte Energieträger. [Online]. Available: https://www.prognos.com/de/projekt/kosten-und-transformationspfade-fuer-strombasierte-energietraeger (accessed: 16-Oct-24).

[52] ITM, NEPTUNE V | ITM: Best-in-class 5MW Plug & Play electrolyser for mid-size projects. [Online]. Available: https://itm-power.com/products/neptune-5 (accessed: 16-Oct-24).

[53] Tom Smolinka et al., „Studie IndWEDe Industrialisierung der Wasser¬elektrolyse in ¬Deutschland: -Chancen und ¬Herausforderungen für nachhaltigen Wasserstoff für Verkehr, Strom und ¬Wärme," [Online]. Available: https://www.now-gmbh.de/wp-content/uploads/2020/09/indwede-studie_v04.1.pdf

[54] The International Renewable Energy Agency (IRENA), „Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5C climate goal," [Online]. Available: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf

[55] U. Caldera, D. Bogdanov, and C. Breyer, „Local cost of seawater RO desalination based on solar PV and wind energy: A global estimate," Desalination, vol. 385, pp. 207–216, 2016, doi: 10.1016/j.desal.2016.02.004.

[56] J. Ikäheimo, J. Kiviluoma, R. Weiss, and H. Holttinen, „Power-to-ammonia in future North European 100 % renewable power and heat system," International Journal of Hydrogen Energy, vol. 43, no. 36, pp. 17295–17308, 2018, doi: 10.1016/j.ijhydene.2018.06.121.

[57] The Danish Energy Agency, Technology Data for Energy Storage. [Online]. Available: https://ens.dk/en/our-services/technology-catalogues/technology-data-energy-storage (accessed: 16-Oct-24).

[58] Sasol Limited, „SASOL Climate Change Report 2023," 2023. [Online]. Available: https://www.sasol.com/sites/default/files/2023-09/SASOL%20Climate%20Change%20Report%202023.pdf

[59] The Danish Energy Agency, Technology Data for Renewable Fuels. [Online]. Available: https://ens.dk/en/our-services/technology-catalogues/technology-data-renewable-fuels (accessed: 16-Oct-24).

[60] Florian Ausfelder and Hanna Ewa Dura, „Optionen fuer ein nachhaltiges Energiesystem mit Power-to-X Technologien," [Online]. Available: https://wupperinst.org/fa/redaktion/downloads/projects/P2X_Roadmap_1-0.pdf

[61] M. Götz et al., „Renewable Power-to-Gas: A technological and economic review," Renewable Energy, vol. 85, pp. 1371–1390, 2016, doi: 10.1016/j.renene.2015.07.066.

[62] B. Balopi, P. Agachi, and Danha, „Methanol Synthesis Chemistry and Process Engineering Aspects- A Review with Consequence to Botswana Chemical Industries," Procedia Manufacturing, vol. 35, pp. 367–376, 2019, doi: 10.1016/j.promfg.2019.05.054.

[63] DECHEMA, „Low carbon energy and feedstock for the European chemical industry," 2017. [Online]. Available: https://dechema.de/dechema_media/Downloads/Positionspapiere/Technology_study_Low_carbon_energy_and_feedstock_for_the_European_chemical_industry.pdf

[64] M. Fasihi, O. Efimova, and C. Breyer, „Techno-economic assessment of CO_2 direct air capture plants," Journal of Cleaner Production, vol. 224, pp. 957–980, 2019, doi: 10.1016/j.jclepro.2019.03.086.

[65] G. Vourliotakis, G. Human, P. Behrens, D. Sarantaridis, S. Karellas, and O. Platsakis, „Carbon Sources for the Production of Power-to-X and Synthetic Fuels in South Africa: Executive Summary," EXERGIA Climate Change Consultants S.A., 2024. Accessed: 22-Sep-24. [Online]. Available: https://ptx-hub.org/wp-content/uploads/2024/02/International-PtX-Hub_202402_Carbon-Sources-for-PtX-in-South-Africa.pdf

[66] Department of Public Works and Infrastructure, South Africa, „Strategic Integrated Projects: Presidential Infrastructure Coordinating Commission Council," [Online]. Available: https://www.gov.za/sites/default/files/gcis_document/202212/47658gon2835.pdf

[67] Green Hydrogen Summit, SIPS | Green Hydrogen Summit. [Online]. Available: https://greenhydrogensummit.org.za/sips/ (accessed: 22-Sep-24).

[68] International Energy Agency (IEA), Hydrogen Production and Infrastructure Projects Database. [Online]. Available: https://www.iea.org/data-and-statistics/data-product/hydrogen-production-and-infrastructure-projects-database (accessed: 22-Sep-24).

[69] Hydrogen Insight, 'Chinese alkaline electrolysers are more expensive when exported – but still a quarter of the price of Western tech': WoodMac. [Online]. Available: https://www.hydrogeninsight.com/electrolysers/chinese-alkaline-electrolysers-are-more-expensive-when-exported-but-still-a-quarter-of-the-price-of-western-tech-woodmac/2-1-1710385

[70] Fraunhofer IEE, Global PtX Atlas | Fraunhofer IEE. [Online]. Available: https://maps.iee.fraunhofer.de/ptx-atlas/ (accessed: 22-Sep-24).

[71] N. Kern, „Supply-Side Cost and Performance Data for Eskom Integrated Resource Planning: 2020–2021 Update,“ Electric Power Research Institute (EPRI), 2021. [Online]. Available: https://www.dmre.gov.za/mining-minerals-energy-policy-development/integrated-resource-plan/irp-2023

[72] Adam Roff, Dr Grové Steyn, Dr Emily Tyler, Celeste Renaud, Rian Brand and Jesse Burton, „A vital ambition - determining the cost of additional CO_2 emission mitigation in the South African electricity system in collaboration with the CSIR Energy Centre,“ 2020. [Online]. Available: https://meridianeconomics.co.za/wp-content/uploads/2020/07/Ambition.pdf

[73] Australian Energy Market Operator, „Integrated System Plan (ISP),“ [Online]. Available: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp

[74] National Renewable Energy Laboratory, „Electricity Annual Technology Baseline (ATB) Data,“ 2023. [Online]. Available: https://atb.nrel.gov/electricity/2023/data

[75] DNV, „Energy Transition Outlook 2022,“ [Online]. Available: https://www.dnv.com/energy-transition-outlook/download

[76] International Energy Agency (IEA), „World Energy Outlook 2023,“ [Online]. Available: https://www.iea.org/reports/world-energy-outlook-2023

[77] Department of Mineral Resources and Energy, South Africa, „Integrated Resource Plan Tech Assumptions,“ 2024. [Online]. Available: https://www.dmre.gov.za/mining-minerals-energy-policy-development/integrated-resource-plan/irp-2023

[78] Department of Mineral Resources and Energy, South Africa, Independent Power Producer Procurement Programme Projects. [Online]. Available: https://www.ipp-projects.co.za/ProjectDatabase/Map

[79] OpenStreetMap, South Africa Power Plants - Open Infrastructure Map. [Online]. Available: https://openinframap.org/stats/area/South%20Africa/plants

[80] Eskom, „Generation Connection Capacity Assessment (GCCA): 2025,“ 2023. [Online]. Available: https://www.eskom.co.za/wp-content/uploads/2023/10/Generation_Connection_Capacity_AssessmentGCCA-2025finalfinal_rev0003.pdf

[81] Peter Klein, Open Energy Systems Modelling Workshops on the PYPSA-RSA model. [Online]. Available: https://meridianeconomics.co.za/our-publications/pypsa-rsa-workshop1/

[82] C. S. Makola, P. F. Le Roux, and D. E. Okojie, „Transmission Line Stability Operation at Surge Impedance Loading,“ 2021. [Online]. Available: http://www.ripublication.com/

[83] S. Karimi, P. Musilek, and A. M. Knight, „Dynamic thermal rating of transmission lines: A review,“ Renewable and Sustainable Energy Reviews, vol. 91, pp. 600–612, 2018, doi: 10.1016/j.rser.2018.04.001.

[84] H. Martin, T. Hamacher, T. A. Deetjen, and M. E. Webber, „Reduced transmission grid representation using the St. Clair curve applied to the electric reliability council of Texas,“ in 2017 14th International Conference on the European Energy Market (EEM), Dresden, Germany, 2017, pp. 1–5.

[85] Department of Mineral Resources and Energy, South Africa, „Commodity Flows and Energy Balances: Mineral Resources and Energy Republic of South Africa,“ [Online]. Available: https://www.dmre.gov.za/energy-resources/energy-statistics-reports/energy-balances

[86] Bruno Merven et al., „Assumptions and Methodologies in the South African TIMES (SATIM) Energy Model,“ 2019.

[87] F. Ahjum, B. Merven, A. Stone, and T. Caetano, „Road transport vehicles in South Africa towards 2050: Factors influencing technology choice and implications for fuel supply," J. energy South. Afr., vol. 29, no. 3, pp. 33–50, 2018, doi: 10.17159/2413-3051/2018/v29i3a5596.

[88] Energy Systems Research Group, „Developing an Integrated Energy Plan in the South African context-a methodological framework: To be published soon.," 2024.

[89] United Nations Statistic Division, Energy Balances 2021. [Online]. Available: https://unstats.un.org/unsd/energystats/pubs/balance/

[90] Alison Hughes, Bruno Merven, and Bryce McCall, „Industrial Sector Energy Demand," 2019. [Online]. Available: https://zivahub.uct.ac.za/articles/dataset/Industrial_Sector_Energy_Demand/7250969

[91] Tamaryn Napp and Bruno Merven, „Iron and Steel Sub-Sector Energy Demand," 2019. [Online]. Available: https://zivahub.uct.ac.za/articles/dataset/Iron_and_Steel_Sub-Sector_Energy_Demand/7250975/1

[92] M. McCarten et al., Global Database of Cement Production Assets. Spatial Finance Initiative.

[93] Global Steel Plant Tracker, Global Energy Monitor, April 2024 (V1) release. [Online]. Available: https://globalenergymonitor.org/projects/global-steel-plant-tracker/download-data/

[94] The FracTracker Alliance, Global Oil Refinery Complex, Daily Capacity, CO_2 Emissions, and Various Ancillary Products Produced. [Online]. Available: https://www.arcgis.com/home/item.html?id=a917ac2766bc47e1877071f0201b6280

[95] S. Jasansky, M. Lieber, S. Giljum, and V. Maus, „An open database on global coal and metal mine production," Sci Data, vol. 10, no. 1, p. 52, 2023, doi: 10.1038/s41597-023-01965-y.

[96] OurAirports. [Online]. Available: https://ourairports.com/data/

[97] National Geospatial-Intelligence Agency (NGA), World Port Index. [Online]. Available: https://msi.nga.mil/Publications/WPI (accessed: 22-Oct-24).

[98] Climate Analytics and NewClimate Institute, South Africa | Climate Action Tracker. [Online]. Available: https://climateactiontracker.org/countries/south-africa/ (accessed: 22-Sep-24).

[99] Nationally Determined Contributions Registry | UNFCCC. [Online]. Available: https://unfccc.int/NDCREG (accessed: 25-Oct-24).

[100] Climate Transparency, „South Africa - Climate Transparency Report: Comparing G20 Climate Action," 2022.

[101] „South Africa's NDC Targets for 2025 and 2030: Technical analysis to support consideration of the emissions trajectory in South Africa's NDC," [Online]. Available: https://pccommissionflo.imgix.net/uploads/images/1eb85a_75d745eb859d43c288f461810b336dd3-compressed.pdf

[102] E. Tyler, C. Renaud, and L. Mgoduso, „The Meaning of „Net Zero" for South Africa and its Power Sector," Briefing Note, 2022. [Online]. Available: https://meridianeconomics.co.za/our-publications/defining-net-zero-for-analysis-of-the-south-african-power-sector/

[103] Department of Forestry, Fisheries and the Environment, „National GHG Inventory Report - 2017: South Africa," 2021. [Online]. Available: https://www.dffe.gov.za/sites/default/files/docs/nir-2017-report.pdf

[104] International Monetary Fund. African Dept., „South Africa Carbon Pricing And Climate Mitigation Policy," IMF Staff Country Reports, vol. 2023, no. 195, 2023, doi: 10.5089/9798400245350.002.A003.

[105] Eskom, „Medium-Term System Adequacy Outlook 2024-2028: Generation System Adequacy for the Republic of South Africa," 2023.

[106] Sasol Limited, „Sasol Climate Change Report 2021," 2021. [Online]. Available: ww.sasol.com

[107] Fertasa - Fertilizer Association of Southern Africa, Fertasa Interactive. [Online]. Available: https://www.fertasastats.co.za/pages/index.php (accessed: 22-Oct-24).

[108] IEA, Renewable Energy Progress Tracker – Data Tools - IEA. [Online]. Available: https://www.iea.org/data-and-statistics/data-tools/renewable-energy-progress-tracker (accessed: 17-Oct-24).

[109] O. Ajayi, „Wind Energy Set to Power South Africa's Renewable Future," The Electricity Hub, 07-Oct-24, 07-Oct-24. https://theelectricityhub.com/wind-energy-set-to-power-south-africas-renewable-future/ (accessed: 05-Nov-24).

[110] IEA, Electricity – Renewables 2023 – Analysis - IEA. [Online]. Available: https://www.iea.org/reports/renewables-2023/electricity (accessed: 17-Oct-24).

[111] CER, „Water Impacts and Externalities: Coal Power," [Online]. Available: https://cer.org.za/wp-content/uploads/2018/07/Water-Impacts-and-Externalities-Brochure_LAC.pdf

[112] N. Mohlakoana, A. Rathupetsane, B. Malope, and M. Jacob, „Demistifying employment in South Africa's Just Energy Transition: Exploring emerging decent work themes," Development Southern Africa, vol. 41, no. 3, pp. 649–665, 2024, doi: 10.1080/0376835X.2024.2352074.

[113] F. S. Ian Sayson, „Fortescue to spend $2.8 billion to electrify mining fleet," Forbes Australia, 26-Sep-24, 26-Sep-24. https://www.forbes.com.au/news/billionaires/fortescue-to-spend-2-8-billion-to-electrify-mining-fleet/ (accessed: 13-Nov-24).

[114] Z. Duma, „The case of green methanol in South Africa: Building a Green Methanol Corridor in South Africa," 2023. [Online]. Available: https://mediafra.admiralcloud.com/customer_609/40f9175f-bf73-43cf-83ff-a87d4875da6b?response-content-disposition=inline%3Bfilename*%3DUTF-8%27%2703_Zama%2520Duma_The%2520case%2520of%2520green%2520methanol%2520in%2520South%2520Africa.pdf&Expires=1730124239&Key-Pair-Id=K3XAA2YI8CUDC&Signature=UZIOYtUpyqyu2mE71T02sT10qPPhW~NPGi4I7MtDhstdDTias8BL~i9jKPlihBpdsU73yn~j5iEeWnMTX5w571Z3cW2SHFwPIIem2d77VyzZqoZWB9ajsMyYR1IEJfuQZQPDaLh1rsDQWfxLA0A0XsMNd8RJuzMe2GHlZkQkGnh-6wjxnJ1xNnnGR9V-pZa79ICoLwiPcd0~OOF0B4taiH8IYuWM~DglvsMq6ct1Vb1dNOYP6oznXfSkDiXXcvTUR5J-0gEsAO9du~etvNja9qCziIuySklhF43OUYTzpKzJY3Umbm3vPhE-LmqxSIw7dEVxJI3QXWnzTe1KkmIZGw__

6 Appendices

6.1 First Stakeholder Consultation Workshop

The workshop (https://www.iee.fraunhofer.de/en/presse-infothek/Events-Trade-fairs/2023/defossilisation-pathways-ptx.html) involved South African professionals from the public, private and academic sectors through discussion in online break-out rooms with the following focus areas:

- transformation of the power sector and PtX production,
- transformation of the transport sector and
- transformation of the industry and mining sector.

Structured as a three-hour session, the workshop comprised three blocks (see Table 35). The initial block provided introductory information corresponding to the project's context. This segment was presented by the affiliated organisation and the consortium, namely GIZ, IEE, and Stellenbosch University. The subsequent section involved participants being organised into three breakout groups each led by a moderator expert on the pertinent topic. Guided topics and questions facilitated interactive discussions, with the support of Mentimeter. The final block of the workshop focused on consolidating and presenting the relevant topics and opinions addressed during the individual breakout sessions.

Table 35: Stakeholder workshop timetable.

Timeslot	Topic	Presenter
09:30 – 9:40	Welcome & Introduction	Alexander Mahler
09:40 – 9:50	Introduction to the context	Zaffar Hussain
09:50 – 10:15	Presentation of the study	Jochen Bard & Lukas Jansen
10:15 – 10:30	Introduction to Breakout Groups	
10:30 – 11:30	A. transformation of the power sector and PtX production	Bernard Bekker & Estefanía Duque
	B. Transformation of the transport sector	Lukas Jansen & Storm Morison
	C. Transformation of the industry & mining sector	Jochen Bard & Zaffar Hussain
	Break	
11:45 – 12:30	Group Conclusion Presentation	

6.2 Further Input Data

6.2.0 Demand data for moderate/delayed transition

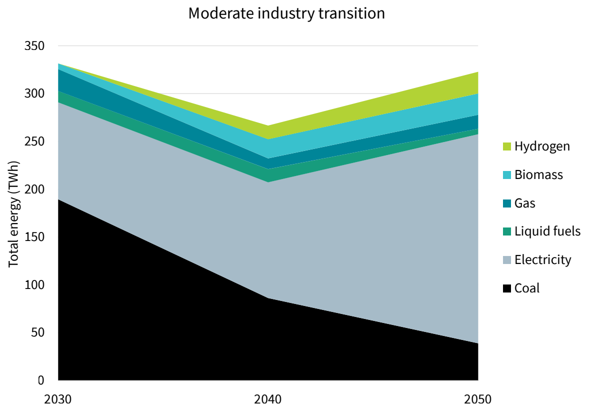


Figure 103: Delayed transition industry sector demand projections.

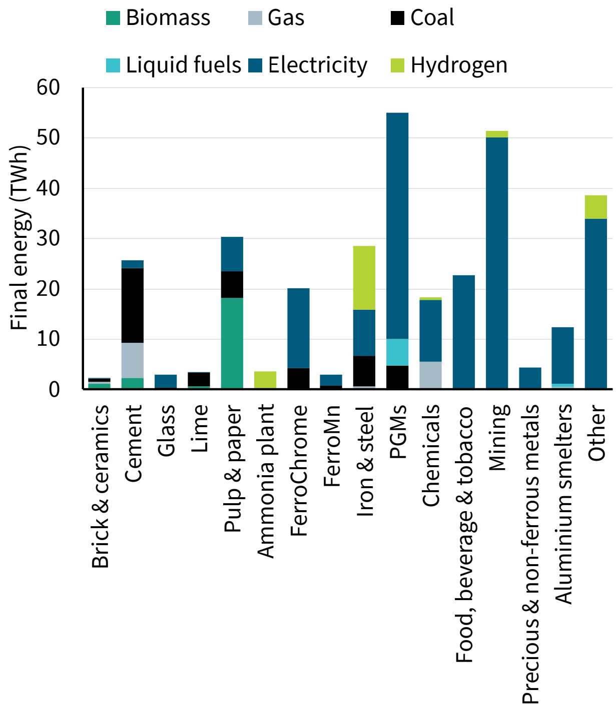


Figure 104: Delayed transition industrial demand projection for 2050.

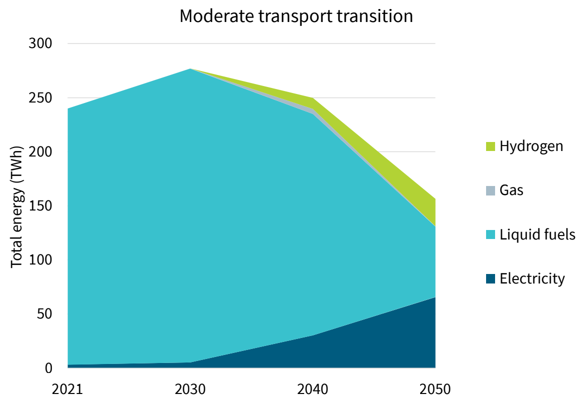


Figure 105: Delayed transition transport sector demand projections.

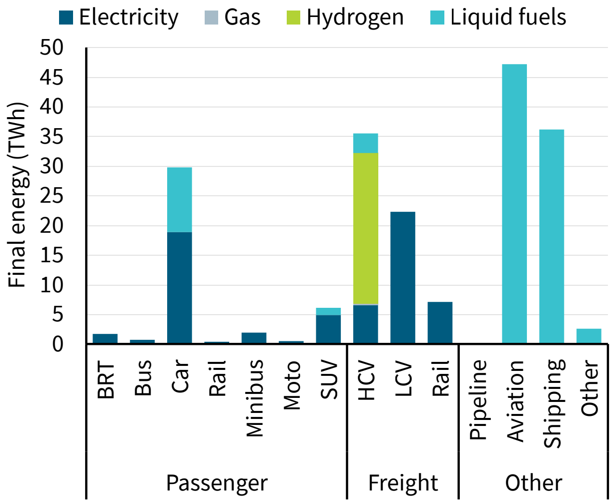


Figure 106: Delayed transition transport demand projection for 2050.

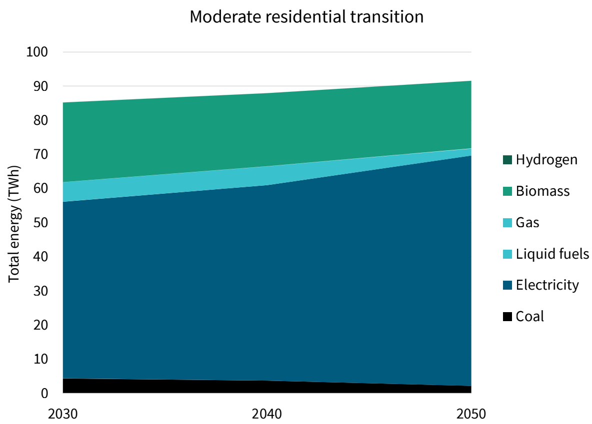


Figure 107: Delayed transition residential sector demand projections.

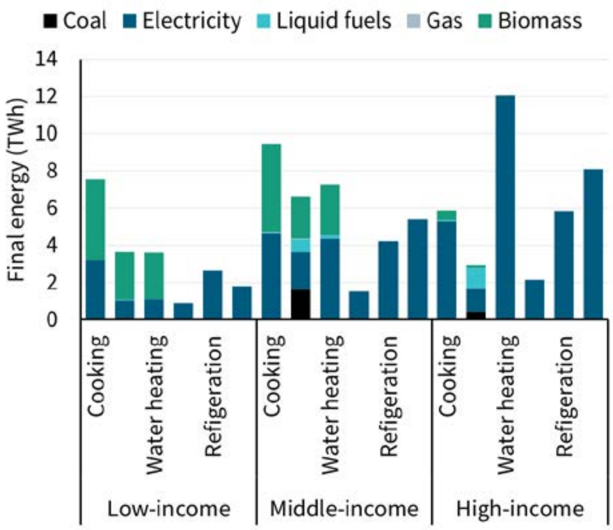


Figure 108: Delayed transition residential demand projection for 2050.

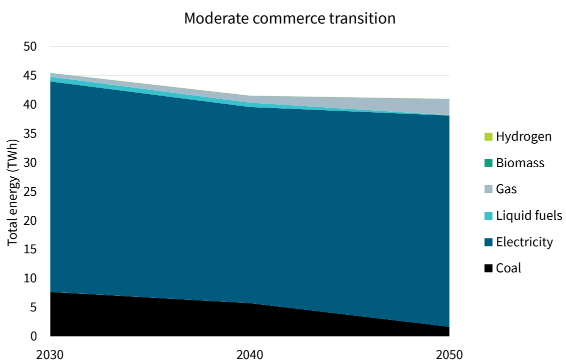


Figure 109: Delayed transition commercial sector demand projections.

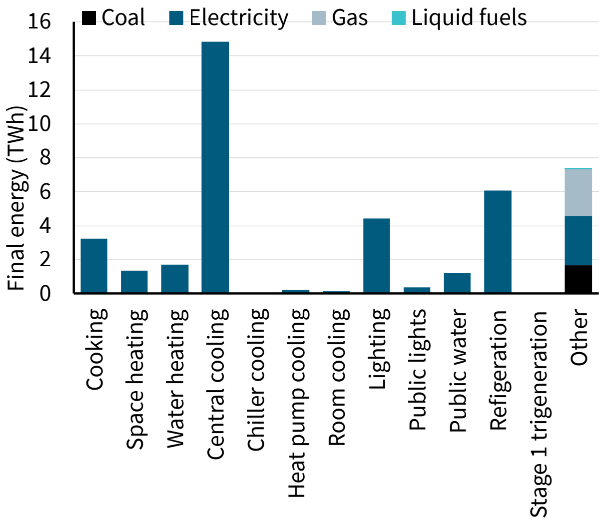


Figure 110: Delayed transition commercial demand projection for 2050.

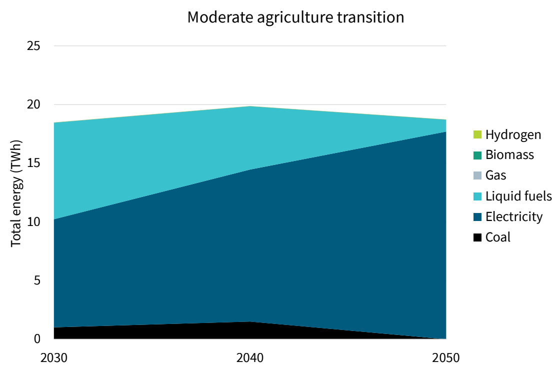


Figure 111: Delayed transition agricultural sector demand projections.

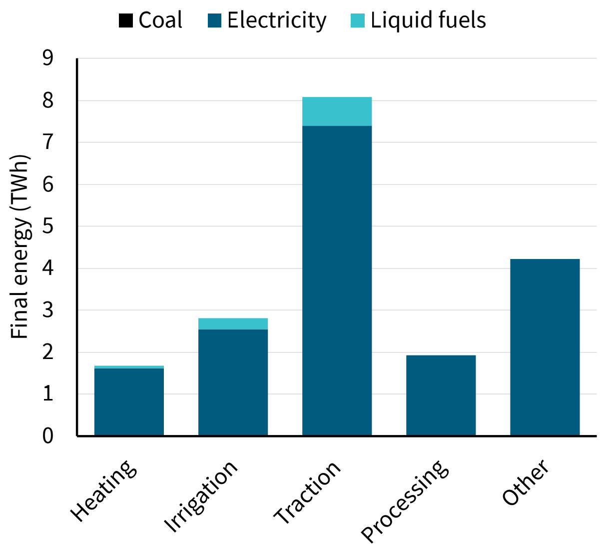


Figure 112: Delayed transition agricultural demand projection for 2050.

6.2.1 Demand data obtained from JET-IP runs for moderate and ambitious transitions

Two demand projection scenarios selected from 65 modelled cases in the JET-IP using the SATIMGE framework were run. IP using the SATIMGE framework. SATIM, an economy-wide partial equilibrium linear optimization model built on the TIMES platform, is maintained by the Energy Systems Research Group (ESRG) at the University of Cape Town. Through SATIMGE, energy carrier demand is determined endogenously based on key drivers like population growth, economic expansion, and sectoral interactions. The model specifies energy service demands, which are then met through demand-side technologies, chosen based on system costs and user-defined constraints, to translate into energy carrier requirements and necessary investments [20]. The demand projections were adjusted to incorporate energy demand data for both international and domestic shipping, sourced from the UNDP [89], as well as potential ammonia production estimates derived from local consumption and potential export opportunities [107].

Download the input datasets: A wide range of input data is required to run the model. Download both original and prepared datasets from **Owncloud**. Download and copy the folders pypsa-rsa-sec/data/bundle and pypsa-rsa-sec/cutouts. By downloading, the user accepts the **licenses** of the original sources.

Summary of first stakeholder workshop takeaways

A total of 43 attendees (excluding the organisers and support team) participated in the event, indicating a no-show rate of 39.5%. Numerous institutions and companies actively contributed valuable insights throughout the workshop, offering significant perspectives on various topics. Notable participants from organisations such as Sasol, Eskom, Transnet, Enertrag, Petrosa, Engie, the Energy Council of South Africa, CSIR, NCEDA, and The University of Kwazulu-Natal, among others, demonstrated a considerable level of interest among the different actors towards the discussion of the energy transition in the country.

6.3 Transformation of the power sector and PtX production

6.3.0 Potential area analysis and technology expansion constraints

- To maximise potential, analysis for green H2 and PtX products should not be constrained by a 500 km distance to ports or pipelines. Building necessary infrastructure should align with regional financial feasibility. Additionally, the georeferenced analysis should incorporate existing plans for green corridors.
- The Mentimeter results revealed that the PV private sectors. Behind The Meter perception of expansion lay between 2 to 3 GW/a from 2030 to 2050, whereas PV utility scale showcased higher expansion rates in 2030 and 2050 (5.4 and 7.2 GW/a respectively) compared to wind (3.9 and 6 GW/a for the same periods).
- Highlighting previously overlooked technologies such as biogas or waste gas in national strategies is crucial in a sector-coupled optimised scenario.

- Defining and determining saturation points for the renewable expansion capacity can be a time-consuming and complex endeavour, especially when assessing realistic saturation levels. Utilising embedded generation drawn from the local demand could insight as potential saturation point.

6.3.1 Grid capacity expansion

- The challenge lies in creating a grid-connected hybrid system that ensures consistent green hydrogen production within uncertainties in the utility sector's supply to H2 plants, while accounting for the varying expenses of electrolysers in on-grid and off-grid systems due to curtailment concerns.

- Multiple uncertainties bundled how green energy might impact policymaking and enable on-demand power, yet stakeholders anticipate that green projects will predominantly remain off-grid. Lack of clarity around the definition of green energy sources and how to access them.
- The results from Mentimeter illustrate stakeholders' views on coal's energy availability, indicating a range of 45% to 65% by 2030 (with an average of 56.2%) and a range of 25% to 77% by 2050 (with an average of 55.6%).

6.3.2 Stakeholder perspective on incorporating nuclear and gas technologies in power generation strategies

- Gas could potentially play a significant role in the short term due to its fast design and build timeline (4 years). It offers easier transportability to demand areas via ISO tankers. Nonetheless, barriers arising from limited gas availability, transmission infrastructure limitations, and diverse users in South Africa, leading to minimal annual construction, need to be surpassed.
- On the other hand, nuclear is a prospective technology despite the lengthy longer-term design and build process (13 – 15 years), albeit could be commissioned from 2035 onwards. While significant preliminary work has been done challenges exist in meeting timelines due to licensing complexities and supplier development, potentially affecting alignment with IAEA requirements.

6.3.3 Scenario design building proposal

- WOM: Scenarios without measures.
- WEM: Scenarios with existing measures.
- WAM: Scenarios with alternative measures. This could be split up into two scenarios, with high and low energy demands from the different sectors.

6.4 Transformation of the transport sector

6.4.0 Electrification & modal shifts

- Cost parity could be less important for public transport electrification and modal shifts. Policies and municipal and national plans may drive progress faster.
- Establishing charging infrastructure is crucial for the deployment of an electrical vehicle fleet. Yet, there is a high level of complexity due to charging times for public transport, particularly BRT. Confidence in the availability of charges for private vehicles will possibly impact the penetration into the market and sales. See charging network of www.gridcars.net. Currently, also off-grid charging networks being implemented as an enabler for green electricity EV charging (https://charge.co.za/).
- Golden Arrow Western Cape's battery electric bus pilot project for commuter services was successful and there are plans to acquire a fleet of buses that will be charged with solar energy. Battery-electric buses are preferred by customers over gas-powered buses. However, there are range concerns for bus operation in normal public transport.
- Project to recapitalise taxis in South Africa has recently been successful and a similar instrument could also be used to promote BEVs.
- Dual fuels offer heavy vehicles the opportunity to enter the fuel cell market (and not just rely on H2 infrastructure). A detailed analysis of the impacts resulting from the flexibility of the e-vehicle fleet and the technology shift towards fuel cell vehicles would be valuable for the study.

- A large part of the low to middle-income population would take rail/public transport if available. Potentially look at scenarios where if rail were to be restored, substantial shift from private to public
- Rail transport should ideally be electrified, whereby the CO_2 reduction depends on the CO_2 intensity of the power grid. Hydrogen locomotives could be an alternative for rail transport.

6.4.1 Maritime & aviation

- The state of the art and expectations regarding future technologies and fuels in maritime transport (shipping) have developed very dynamically in recent times. Ammonia and methanol engines are becoming available, and regulations are in the works (expected by the end of the decade).
- Aviation sector has strict technical standards. The required amount of fuels can likely only be met in the future through PtX synthetic fuels. Likelihood of large-scale success in maritime & aviation alternative fuels is unconfirmed at this stage. For currently approved sustainable aviation fuels check out:
- https://www.icao.int/environmental-protection/GFAAF/Pages/Conversion-processes.aspx
- https://renewable-carbon.eu/news/astm-decision-brings-100-saf-certification-within-reach/

6.5 Transformation of the industry & mining sector

6.5.0 FT & coal to liquids

- Existing technology with niche applications (FT processes & CtL facilities particularly at Sasol) run risk of being stranded assets in the post-Paris world- carbon taxes and CBAM will drive the CO_2 intensity reduction. Important to incorporate plans and incentives for existing facilities to produce fuels using green H_2.
- 30% GHG emission reduction commitment is becoming more a matter of survival. Sasol uses 2.4 Mt of grey H_2, switching to green would make a substantial difference. Reasonable to stick with 30% GHG reduction by 2030 as announced. Agreed that 10 % CO_2 reduction could be the low end with 30% reduction by 2030 a middle pathway. 35% for innovative scenario reduction- if combined with LNG where gas pipeline infrastructure is repurposed to hydrogen pipelines.
- Sasol's plans and targets have been incorporated into the Northern Cape Master Plan.
- Ammonia is expected to be only produced for export until 2030, for domestic demand only thereafter.
- CO_2 sources for hydrocarbon production from ethanol production in the short to medium turn, DAC to be considered in the innovative scenario.
- The mining industry has site-specific targets only, typically a 10% reduction by 2030 and carbon neutrality by 2050. Solutions for green vehicle fuels using FCs and dual fuel technologies.

6.5.1 Iron & steel

- 5 Mt produced in the country, will add another 1 Mt to the production. Plans to move away from blast furnace (BF) to Electrical and direct reduced iron (DRI), and from coal to low carbon alternatives.
- Currently three BFs, one will be stopped by 2030, two by 2040, and zero in operation by 2050 – all roughly the same size.
- DRI will be in Saldanha – 800,000 ton of DRI using 40 Kton H_2/year. 2032 ramp up to 1.2 Mt DRI using 60 kt green H_2. The rest of the country 1.5 – 2 Mton, all produced by electrical steel. Pelletisation of iron ore is important for shipping, hence the relevance of H_2 for this process, bound to a significant impact on carbon.

- If carbon capture & and utilisation (CCU) is commercially viable then CCU assumptions can be included in the innovative scenario and 25% GHG reduction by 2030 and by 2050 CO2 neutrality could be reached.

6.5.2 Cement

- Unfortunately, no real experts from the sector present.
- Typically, production for regional demand only. Fragmented regionally “closed shop” business.
- This energy sector transformation could be challenging to model with generic assumptions, one of the associations can potentially be contacted (i.e. Concrete Manufacturer Association CMA).

6.6 Concluding remarks

- The Energy Council team have indicated interest in collaborating and possibly using the outputs of the project in their work, exemplifying the uptake of our results. It was communicated that they have a number of initiatives on the go that will complement this work.
- The energy landscape in South Africa is dynamic/in a state of change. Since completion of the workshop the following developments have been released
    - Sasol released a statement admitting they might not meet their 2030 emission reduction targets, contrary to the feedback provided in the workshop (https://justshare.org.za/media/news/sasol-admits-that-it-may-not-meet-its-2030-emission-reduction-targets/)
    - The medium-term system adequacy outlook signals a departure from previous forecasts and initial plans which saw over 6000 MW of coal capacity shut down by the end of 2028 (https://www.moneyweb.co.za/news/south-africa/eskom-plan-sees-no-coal-shutdown-until-2028-at-least/)
    - New transmission plans were recently released (https://www.eskom.co.za/eskom-divisions/tx/gcca/gcca-2025/)
    - The Integrated Resource Plan 2023 was published and released for public comment