REVIEW OF THE IRP 2023

COMMENTS FOR SUBMISSION TO THE DIRECTOR-GENERAL OF THE DEPARTMENT OF MINERAL RESOURCES AND ENERGY

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MERIDIAN ECONOMICS
NAVIGATING COMPLEXITY

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EXECUTIVE SUMMARY

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INTRODUCTION

WHY THE NEED FOR INDEPENDENT INTEGRATED RESOURCE PLANNING ANALYSIS?

- The DMRE published the IRP 2023 on 4th January 2024 with (extended) time for comments until 23rd March 2024
  - Every South African is impacted by the future of the power sector and informed, robust engagement from multiple stakeholders is key to ensure final decision-making is rational and in the best interests of the country
- Power system planning is a complex task requiring specialist simulation software to integrate myriad assumptions in order to derive possible futures for our power system. This analysis is beyond the scope of most stakeholders
- Without independent integrated resource planning analysis, stakeholders are limited to the possible pathways and inherent assumptions in the IRP 2023
  - Assumptions and especially their consequence is not always clear from the resultant pathways
  - Alternative pathways based on alternative assumptions are essential for consideration – especially in light of the inherent uncertainty in forecasting key parameters such as technology cost, demand, build limitations, grid constraints, coal fleet performance, fuel prices and future carbon emission consequences
- The purpose of publishing this analysis is to empower stakeholders to make informed comment, and participate meaningfully in the engagement process with DMRE as the power system plan is finalised
  - First we review the approach, assumptions and methodology employed in the IRP 2023, and then the resultant power system plan itself.
  - Second we explain the approach and assumptions we have employed and why.
  - Third we present the results of our analysis and the summary findings from multiple scenarios of different cost, constraint and performance assumptions
  - Finally we conclude and provide recommendations for the IRP process and immediate interventions in the power system

Review of the Approach, Assumptions & Methodology employed in the IRP 2023

IRP 2023 APPROACH

MAJOR PROBLEMS WITH THE APPROACH RENDER THE IRP 2023 DRAFT INADEQUATE AND OPAQUE

1. **Core planning objectives of adequacy, affordability and environment are unmet**
   - The IRP 2023 does not provide for an adequate power system in the short term, and in some cases long term adequacy is also not achieved.
   - A net-zero trajectory is not achieved in any scenario, and local air pollution is ignored when evaluating coal expansion scenarios.
2. **Failure to account for uncertainty**
   - There is significant uncertainty in the planning horizon (in demand, fuel prices, domestic and international carbon pricing, coal performance and technology advancements) which the IRP analysis does not engage with.
   - Planning in uncertainty requires understanding the implications of this uncertainty across parameters, and a focus on developing options and resilience, which is not considered.
3. **Lack of transparency**
   - Key methodological aspects are undisclosed, making it difficult to re-construct the modelling or engage with the outcomes.
   - The unusual technology cost assumptions remain unmotivated.
   - There is no systematic evaluation of scenario performance against the planning objectives of security of supply, cost and environment.
4. **Inadequate process**
   - The draft for stakeholder comment is highly opaque, significantly complicating its review.
   - The DMRE has stated that the IRP draft is still to be ‘policy adjusted’. No provision is made for stakeholder comment on this critical aspect, which may result in a very different ‘Emerging Plan’.
   - The IRP 2023 does not include Nuclear in either the Emerging Plan to 2030 or the Reference Pathway to 2050, but a large Nuclear RfP will imminently be issued to market leaving the legitimacy of either the IRP or the RfP in question.

IRP 2023 METHODOLOGY

THE METHODOLOGY USED IS CONFUSING AND DOES NOT SUBSTANTIATE THE EMERGING PLAN

- **Lack of optimisation:** While the inclusion of a long-term planning horizon to 2050 is useful, the Horizon 1 analysis only considers capacity currently in development, with no power system optimisation conducted to determine potential additional new capacity that may end loadshedding sooner.
- **Use of predetermined technologies:** The Horizon 2 analysis presents five pathways for the power sector, each of which represents a different combination of technology options. Since these technology combinations are determined prior to optimisation, they are necessarily sub-optimal, presenting a false choice of options from a limited set of seemingly arbitrary and unrealistic technology combinations.
- **Inexplicable new-build limits:** Excessively stringent (and undisclosed) annual build limits are applied to Solar (capped at 900 MW) and Wind (capped at 1720 MW) in the Horizon 2 analysis, significantly constraining their deployment. There is no rational basis for such binding constraints, with 2.5 GW of rooftop Solar PV added in SA in 2023 alone (and 5GW of panels imported). Moreover, the application of build limits is inconsistently applied. In Pathway 2 for example, Solar PV is severely constrained limiting its installed capacity to 18 GW by 2050. By comparison, 34.5 GW of unconstrained CSP is built over the same period, equivalent to about 5 times current total global installed capacity.
- **Coal decommissioning schedule:** The IRP 2023 takes Eskom's coal decommissioning schedule as given. Particularly given the environmental issues associated with coal use, earlier retirement of the coal fleet must be considered.

IRP 2023 ASSUMPTIONS

COMPARATIVE ANALYSIS OF TECHNOLOGY AND COST ASSUMPTIONS

- Several of the cost assumptions used as inputs for the IRP 2023 are problematic:
  - Technology costs for Wind, Solar PV, CSP and Battery Storage are significantly higher than the actual realised market pricing from recent REIPPPP and BESIPPPP bid windows and other reference data sets (see comparative LCOE charts for solar PV and wind in the technical appendix).
  - The IRP 2023 ignores future technology learning, and as a result the cost of new technologies (Wind, Solar, Batteries) are inflated relative to more mature technologies (Coal, Nuclear, Gas).
  - Nuclear costs used were those received from vendors through the recent RFI. These are non-binding and very low compared to any other data sources – including actual costings from projects under construction.
  - Neither Flue Gas Desulphurisation retrofits (required to meet MES regulations) nor Carbon Capture, Utilisation and Storage (CCUS) costs are provided or included in the IRP analysis.
- Meridian's cost and technology assumption comparative analysis published 2 February 2024, situates the IRP cost assumptions against recent and authoritative datasets.

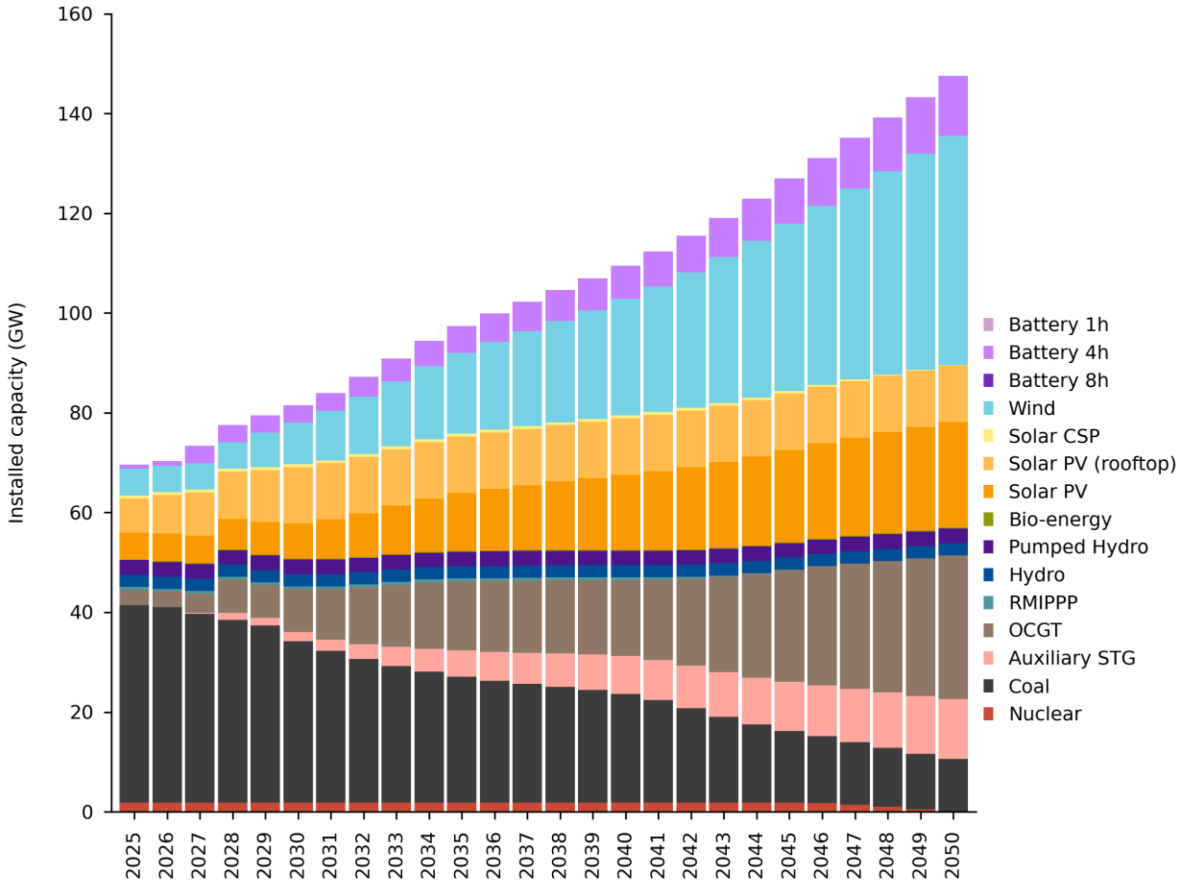
Review of the IRP 2023 plan

IRP 2023 PLAN

UNREALISTICALLY CONSTRAINED, OVER-PRICED RENEWABLES RESULT IN GAS-HEAVY PLAN

- In this analysis the "IRP 2023" refers to a power system plan that follows the Emerging Plan for Horizon 1 to 2030 (i.e. Table 2 of the IRP document) and then installs capacity according to Pathway One (the Reference Pathway) for Horizon 2 (2031 – 2050)
- The installed capacity is charted and tabulated in the following slide
- Notable features of the plan include the following:
  - The plan replaces retiring coal capacity with gas. This maintains the capacity of fossil fuel generation roughly constant, rising slightly such that by 2050 installed capacity of coal and gas-fired generation exceeds current capacity of these technologies
  - Approximately 10GW of coal capacity remains online in 2050
  - No new nuclear power is built i.e. the soon-to-be released RfP for 2.5GW of nuclear power is not represented in the plan
  - The plan relies heavily on gas power to address load shedding and provide long term energy security
  - The plan assumes power availability from all RMIPPPP and REIPPPP projects but significant capacity in these programmes has failed
    - When accounting for the actual state of these projects the IRP 2023 will result in extreme levels of loadshedding until 2029

THE IRP REFERENCE CASE SEES INCREASING CAPACITY FROM SOLAR, WIND AND BATTERY STORAGE. COAL IS REPLACED BY GAS.



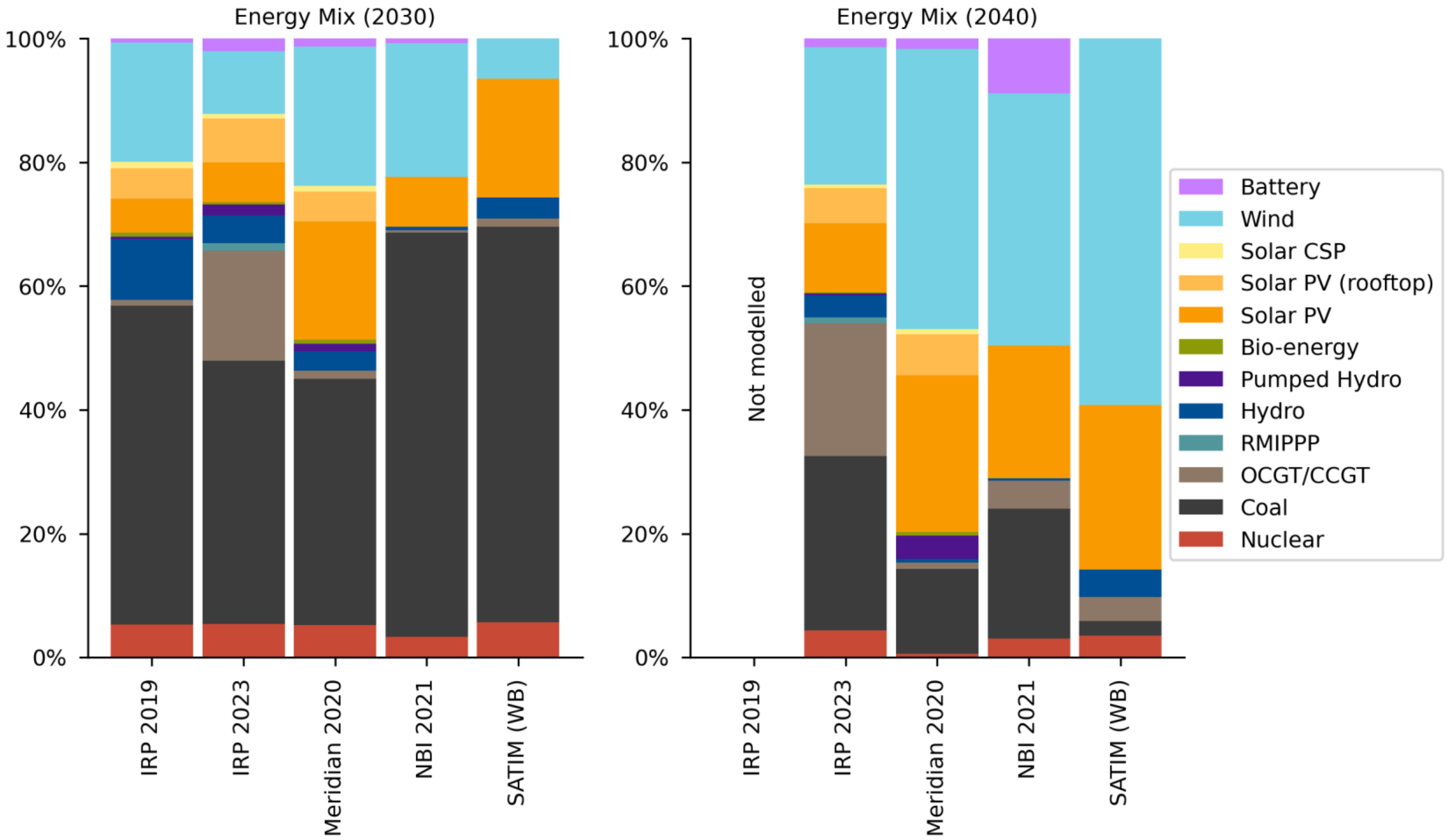
Installed capacity in IRP reference case
(without RMIPPPP/REIPPPP that have failed to reach financial close)

Technologies	2025	2030	2040	2050
Coal[1]	39.6	32.4	21.8	10.6
Nuclear	1.9	1.9	1.9	0
OCGT/ICE[2]	3.5	9.1	15.2	28.8
Auxiliary STG	0	1.8	7.6	12
RMIPPPP	0.2	0.6	0.6	0
Solar PV[3]	7.8	18.4	26.3	32.5
Solar CSP	0.5	0.6	0.6	0.1
Wind	3.5	8.3	23.4	46
Battery storage	0.2	3.5	6.6	12
Pumped hydro[4]	2.9	2.9	2.9	2.9

[1]Includes Sasol coal generation
[2]Includes Sasol gas fired generation
[3]Includes utility and rooftop solar PV

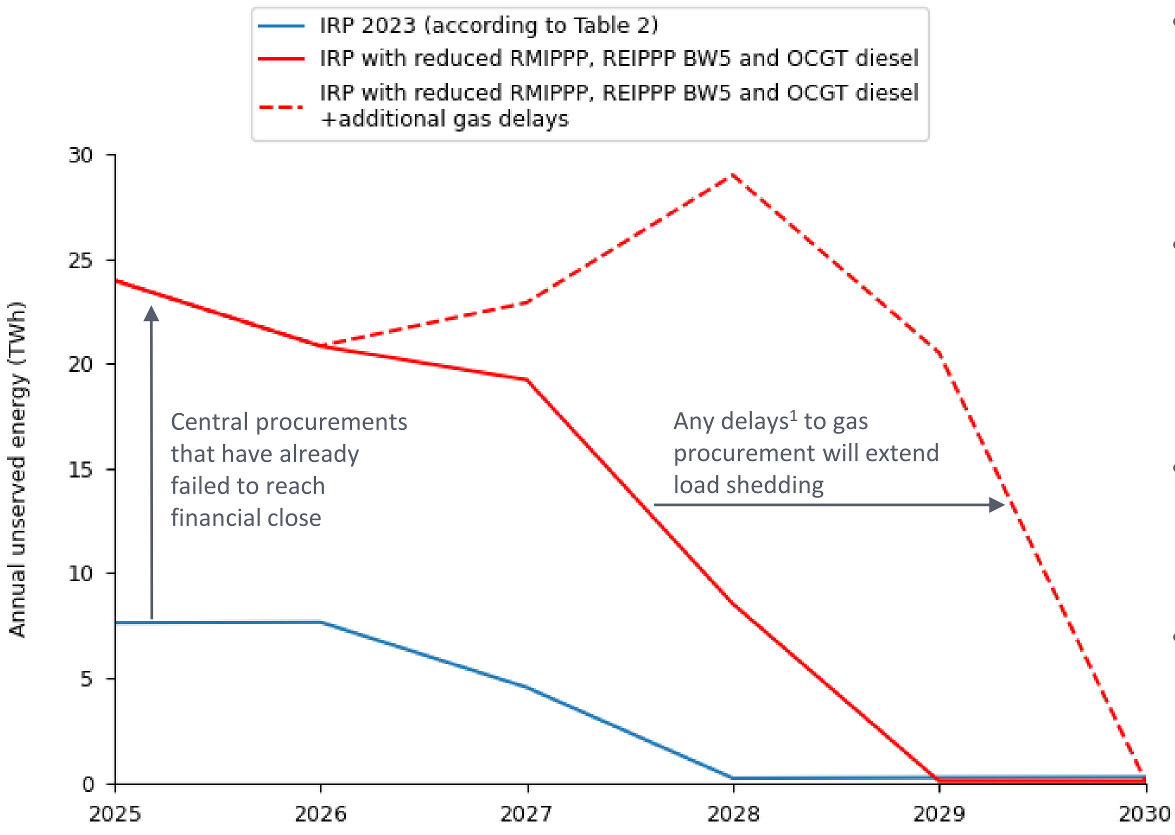
THE RESULTING ENERGY MIX IN THE IRP 2023 REFERENCE SCENARIO WILL SEE AN EXPANDING ROLE FOR GAS THAT EXCEEDS RESULTS OF PREVIOUS STUDIES

- Previous studies of the South African Power system assumed a higher coal fleet availability than the IRP 2023. Most of these studies were published before 2022, when there was a significant increase in coal station outages.
- By 2030, IRP 2023 envisages that gas energy will replace the energy that can no longer be generated from an underperforming coal fleet.
- By 2040, the role of gas is further expanded in the IRP 2023. This gas usage is significantly higher than other studies, whilst renewable energy (particularly from wind), is much lower.



IRP 2023 does not provide any capacity factors for gas generation post 2030. This graphic is based on calculation from a modelled scenario of the IRP reference case, assuming a minimum 30% annual capacity factor on Combined Cycle generation

THE IRP EMERGING PLAN FOR HORIZON 1 SIGNIFICANTLY UNDERESTIMATES THE LOAD SHEDDING RISK



[1]Gas capacity delays applied of 2yrs, moving capacity to 2029 and 2030

- The draft IRP 2023 includes the full installed capacity from gas to power RMIPPPP projects in 2025. Assuming an annual capacity factor of 50-80%, this equates to an additional 5-8.5 TWh/y of generation that will not materialise given the failure of these projects to reach financial close.
- It is also assumed that 2115 MW of solar PV from REIPPPP BW 5-6 will be installed, whereas only 1525 MW can be achieved. For wind, 1468 MW is assumed from REIPPPP BW5 whereas only 768 MW reached financial close.
- The existing diesel OCGTs are shown to have capacity factors of over 70% in 2025 in the IRP Table 3, which is more than double that which Eskom has been able to achieve in 2023 due to fuel resupply logistics.
- Emerging Plan results in cumulative loadshedding of 21 TWh from 2025 to 2030 as published. When considering above factors, the total is 73 TWh.
  - This means loadshedding worse than 2023 levels until 2027
  - The IRP is heavily dependent on additional gas generation capacity to be installed in 2027-2028. If this is delayed, loadshedding is likely to be further extended to 2030.

POLICY MISALIGNMENT

THE CURRENT DRAFT IS FUNDAMENTALLY POLICY MISALIGNED ACROSS NUMEROUS POLICY AREAS

- **While our view is not that current policies about the long-term future should be cast in stone, it is important for a new policy document such as the IRP to engage explicitly with key prior existing policies that it differs from.**
- **Climate commitments:**
  - The IRP 2023 assumes an NDC-aligned range for the power sector of 160 – 180 $MTCO_2e$ by 2030. No basis is provided for this range however it appears high given that the greatest economy-wide mitigation potential lies in the power sector.
  - SA's Low Emission Development Strategy sets an economy-wide goal of net zero emissions by 2050. Despite clarification from the DMRE that the IRP 2023 includes planning pathways to achieve net zero in the electricity sector by 2050, none of the scenarios achieve this goal.
- **Air quality:**
  - While acknowledging the need to manage MES compliance, none of the IRP 2023 scenarios include local air quality concerns as a constraint on future generation options.
  - The IRP 2023 should at least consider the cost and downtime implications of local air pollutant retrofits at any coal plant included in its coal extension scenario.
- **Green industrialisation:**
  - The Emerging Plan from the IRP 2023 Horizon 1 analysis includes only 17.3 GW of new additional renewable energy capacity by 2030 compared to 50 GW outlined in the Just Energy Transition Investment Plan. This, together with the stop-start pattern of investment, sends poor market signals to investors and threatens the viability of developing local green value chains.
- **Nuclear:**
  - Although poorly considered, the National Infrastructure Plan expresses a need for 'baseload' nuclear to support a large rollout of renewables. Additionally, there is currently a 2.5 GW RfP for nuclear underway. There is however a conspicuous absence of nuclear in both the Emerging Plan in Horizon 1 and the Reference Pathway in Horizon 2. Pathway 3 is the only scenario to include nuclear however this is only due to the inappropriate application of binding constraints on other technologies.

An independent IRP

(Approach and Assumptions)

THE POWER SYSTEM MODELLING ENDEAVOUR

THE IRP PURPOSE : ENSURE SECURITY OF SUPPLY, WHILE CONSIDERING ENVIRONMENT AND TOTAL COST OF SUPPLY

- Power system modelling involves the use of simulation software to determine the necessary installed capacity of different generation technologies in order to ensure that the country's demand for electricity in any hour can be met by supply from the fleet of generators.
- Many different permutations of capacity and technology can equally ensure security of supply, however these alternative power systems will all have different total cost of supply and will generate different levels of carbon and other emissions
- Power system optimisation involves selecting from the myriad possible plans, the options that will meet future emissions reduction targets and do this at minimal overall cost of supply, without jeopardising security of that supply
  - The optimisation must take account of not only constraints on emissions into the future, but an array of other real-world practicalities such as the lead times for different technologies, the impact of grid constraints on the deployment of technologies particularly wind and solar capacity, and simple practical constraints around port capacity, logistics, engineering, procurement and construction capacity in the country.
  - Formally, the optimisation minimises an "objective function", whilst ensuring that the constraints for a particular scenario (e.g. annual build limits on renewables) are respected.
    - The objective function includes the sum of all Capex, Opex and fuel cost that will be incurred by the plan from 2025 – 2050 (future costs are discounted at 8.2% real)
    - The objective function also includes a penalty cost for load shedding at R100/kWh, and a penalty cost on carbon emissions for two of the Net Zero pathway scenarios
  - For each scenario investigated we report difference to the IRP of: the penalty cost of load shedding; the power system cost; the penalty cost of carbon emissions
- Fundamental differences between our analysis and that presented in the IRP include:
  - Our analysis makes no distinction between Horizon 1 (based on existing plans) and Horizon 2 (based on optimised capacity), but considers candidate new capacity can be built as soon as lead times and other constraints allow
  - We have not used the technology cost assumptions in the IRP but used a reasonability overlay on the EPRI assumptions, other sources, and our previous work. See technical appendix
- We explored multiple scenarios in an attempt to quantify impact of uncertainty on near-term decisions
  - Unless explicitly stated otherwise the "base case" refers to a scenario using the base case technology costs and base case renewable build rate assumptions

AN OPEN ENERGY MODELLING APPROACH

FULLY TRANSPARENT DATA AND MODELLING - OPEN-SOURCE CODE, INPUT ASSUMPTIONS AND OUTPUT DATA

- **Transparency is key for enhancing the technical rigour of any capacity planning exercise**
  - Decisions made in the modelling approach can significantly change the result from the optimisation. Capacity expansion models are complex, and many trade-offs must be made to keep the models tractable.
  - At a minimum detailed input and output data should be provided that will allow other modelling teams to fully replicate the IRP results. Where any significant differences emerge for similar input assumptions, these can then be interrogated between stakeholders.
  - Further transparency includes opening the actual model itself, so that each technical modelling decision is visible. Commercial tools such as PLEXOS allow for an export of the modelling variables to Excel, which could be made public after removing confidential information.
- **Modelling Platform**
  - This work utilises the PyPSA-RSA model (available here), based on the Python for Power System Analysis (PyPSA) platform. The model and data is fully open for any stakeholder to interrogate and use to replicate our analysis. A commercial solver back-end is required to resolve the abstracted mathematical optimisation problem for larger models.
- **Temporal Resolution**
  - We solve our model in full time chronology, meaning that 8760 hours are modelled in each year (no time sampling). This allows the impact of full variability in hourly renewable energy generation to be reflected in the optimisation outcome.
  - Multi-horizon expansion is done on a “Perfect foresight” basis where all years are included in the optimisation. Given the uncertainty of input parameters post 2030, we solve every year from 2025 to 2030, and in 5-year steps from 2030 to 2050. This allows for the full chronology approach to be used in each year, whilst keeping the simulation times to below 1 hour per run. This allows rapid feedback and improvements to the model set-up.

The complete configuration files, input and output data used in our modelling are available on request

FORECAST DEMAND FOR ELECTRICITY

RISING DEMAND FOR CARBON-FREE POWER

- With limited time available we have not modelled multiple demand scenarios but used the same assumption published in the IRP

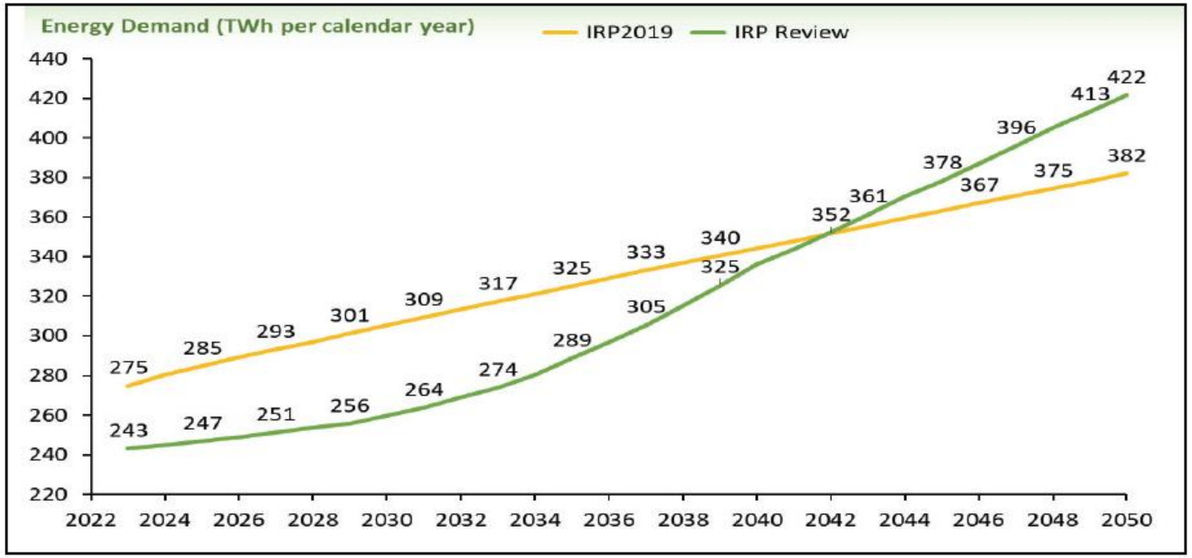
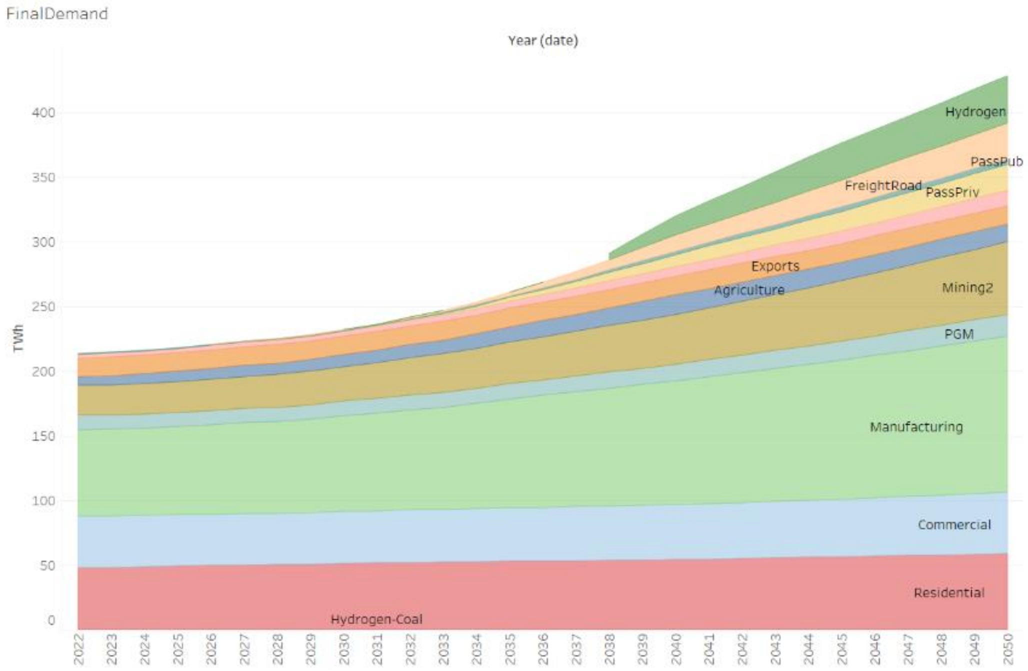


Figure 2: Energy Demand (TWh per calendar year)



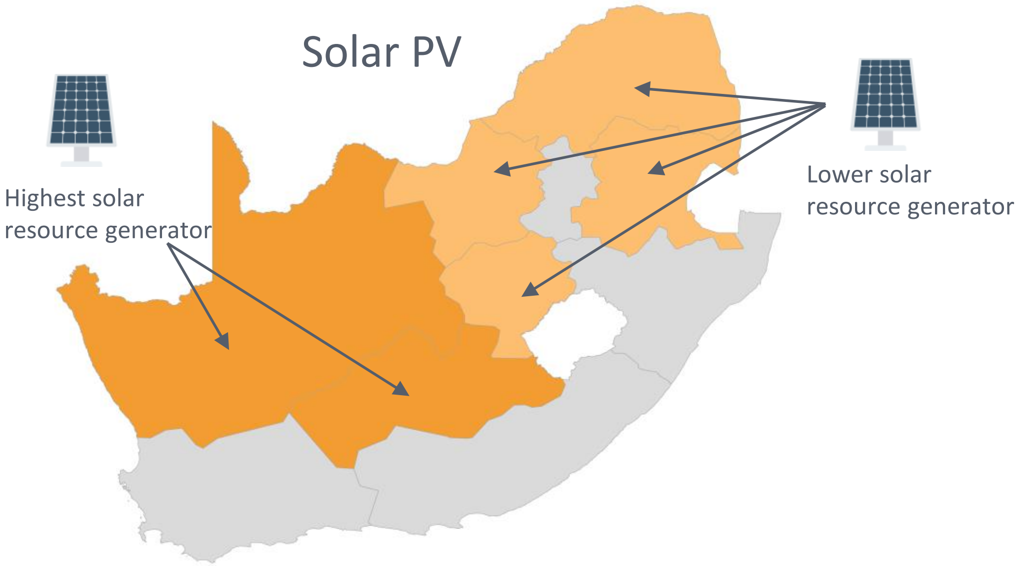
- Both the IRP and the SANEDI publication upon which the demand is based state that Hydrogen is excluded from the demand although the published IRP demand (LH chart) appears to include Hydrogen (RH chart from SANEDI publication)

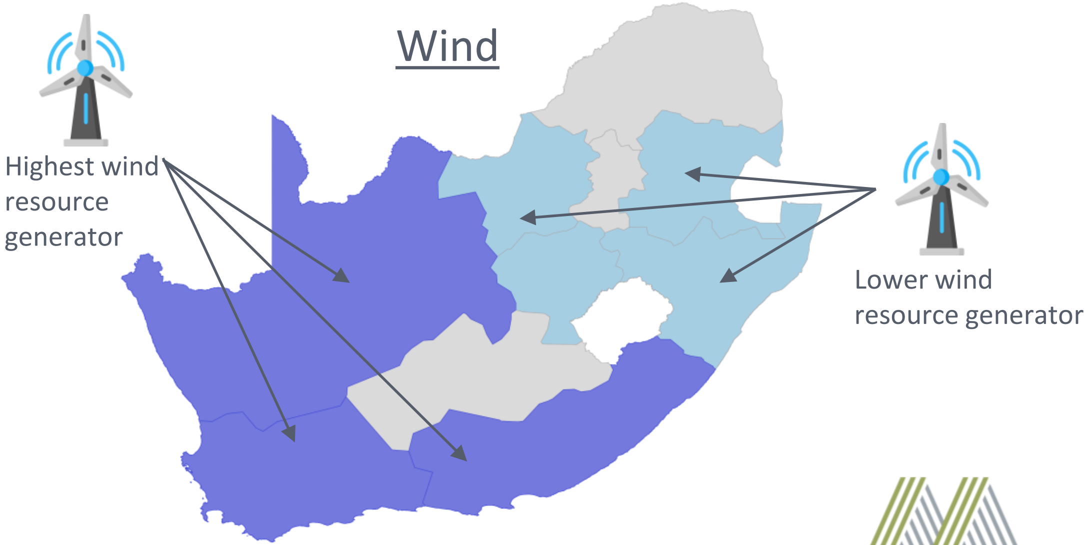
- What is clear is that a substantial part of future demand will be from new sources (such as transport) requiring emission-free power, as well as existing sources increasingly pressured to demonstrate low carbon energy sources.
  - Divorced from this reality, the IRP 2023 plan sees almost 50% of electricity generation remaining from fossil fuels in 2050

ACCOUNTING FOR GRID CONSTRAINTS

IMPACT ON RENEWABLE BUILD RATE AND COST CAUSED BY TRANSMISSION CONGESTION

- The version of the PyPSA-RSA model used for this work is based on a copper plate model where the transmission network is not included (single node – comparable to the IRP PLEXOS model).
- A spatially disaggregated version of PyPSA-RSA is also under development that allows for 10 to 34 nodes.
- To simulate the effect of grid constraints, wind and solar PV generators are split into two separate generators, respectively. The high resource generator is located behind grid constraints, whilst the moderate resource generator is in areas where more grid capacity is available. The hourly resource profile is based on a spatially aggregated profile of each selected province assuming only suitable areas in the Planned Power Corridors, Renewable Energy Development Zones or where an EIA exists.
- In any hour, the combined generation from solar PV, wind and solar CSP in the grid-constrained regions, cannot exceed the limits published in the GCCA. Curtailment is provided as an option in the model.





PLANNING RESERVE MARGIN

USED TO ENSURE ADDITIONAL DISPATCHABLE ENERGY IN THE SYSTEM FOR RESERVES AND CONTINGENCIES

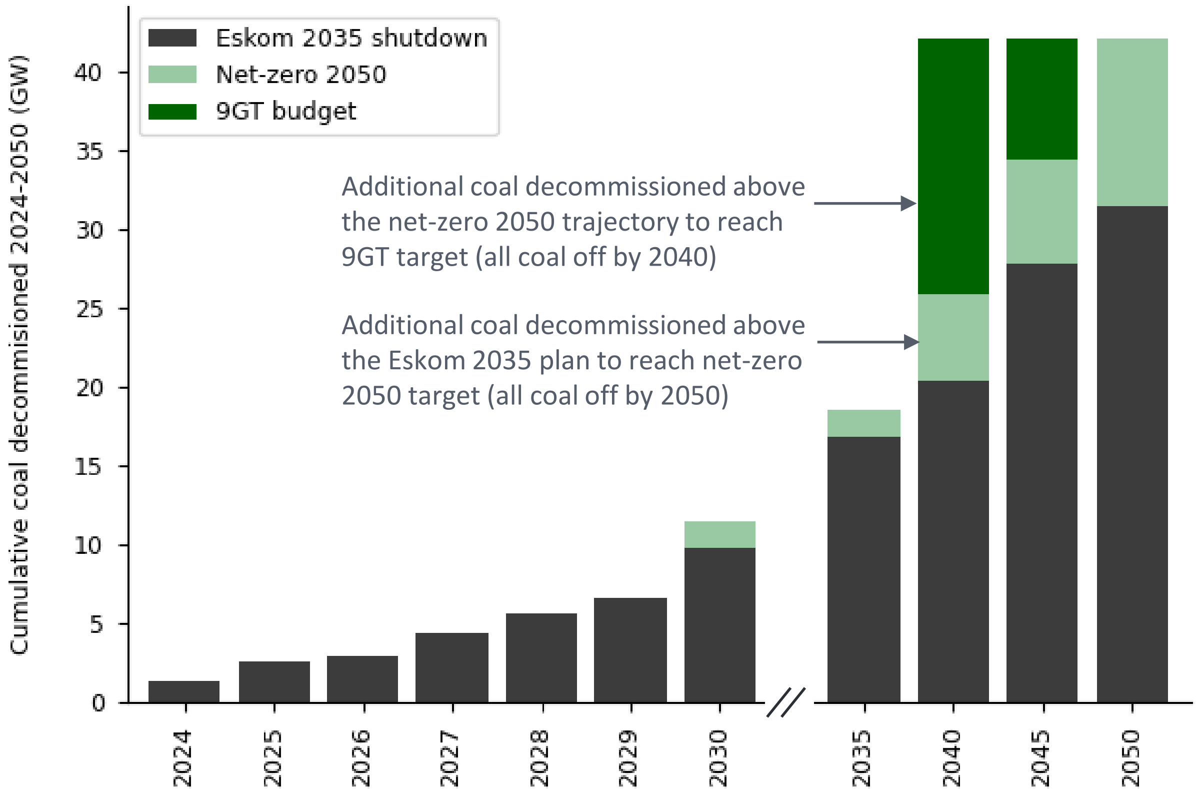
- Capacity expansion models are deterministic, based on specified hourly profiles for demand and variable renewable generation.
- A planning reserve margin is typically included to create additional generation headroom to avoid any risks of unserved energy due to stochastically driven events. Historically a 10-15% planning reserve margin was targeted.
- A planning reserve margin of 10% means that the sum of installed capacity multiplied by capacity credit used for each must be greater than 110% of the maximum expected demand in each year.
- For consistency with other studies, we have applied a 10% planning reserve margin with relatively standard capacity credits for conventional generation (see table). Given the reliability of the coal fleet its capacity credit is unlikely to materialise. However, the relevance of the planning reserve margin itself is no longer clear as the penetration of renewable energy increases, and this is therefore an area where further research is required.

Technology	Capacity credit
Coal	100%
Nuclear	100%
OCGT/CCGT	100%
Solar PV	0%
Wind	10%
Pumped hydro	100%
Battery storage 1h	25%
Battery storage 4h	50%
Battery storage 8h	50%

COAL DECOMMISSIONING SCHEDULE

THREE DIFFERENT SCHEDULES ARE APPLIED EXOGENOUSLY TO THE OPTIMIZATION MODEL, WITH INCREASING LEVELS OF DECARBONIZATION AMBITION (ESKOM 2035 PLAN -> NET-ZERO BY 2050 -> 9GT BUDGET)

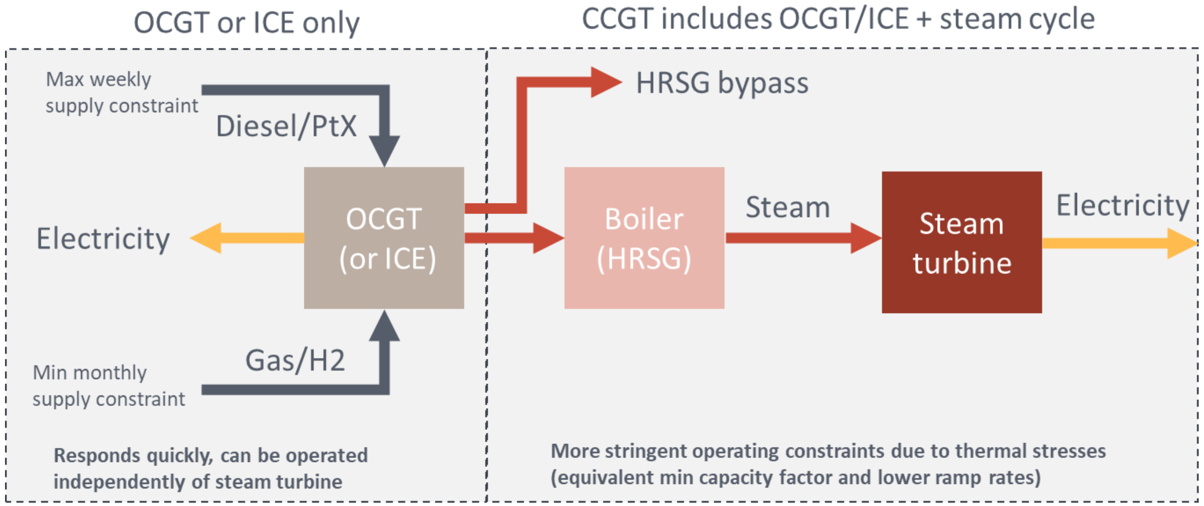
- The Eskom 2035 shutdown plan (decommissioning schedule) is provided in the IRP 2023 document at a unit level per station.
- To reduce computation cost we do not model all units per station (typically 6), but instead split the station into 2 or 3 generators with different decommissioning dates.
- PyPSA-RSA does not yet include the ability to decommission capacity across a year (only at start of year).
- The combination of the two above factors means that some of the decommissioning dates have to be adjusted to approximate the overall IRP decommissioning profile.
- Decommissioning of all other existing technologies is based on the technical lifetime of the projects
- Alternative decommissioning schedules are used for the NZ scenarios, which include:
  - Net-zero by 2050 : all coal decommissioned by 2050
  - 9GT budget: all coal decommissioned by 2040



1440MW of new capacity added in 2024/2025 from Kusile

DISPATCHABLE GENERATION IS MODELLED BY SPLITTING PRIME MOVER (OCGT/ICE) AND AUXILIARY STEAM TURBINE

- Typically, dispatchable gas/diesel fired generation can be a simple cycle Open Cycle Gas Turbine (OCGT) or Internal Combustion Engine (ICE).
- By generating steam with the exhaust heat from the OCGT, it is possible to significantly improve the efficiency of the cycle. This is referred to as a Combined Cycle Gas Turbine.
- Most power models use a single generator component to represent a CCGT. However, the operating characteristics of the OCGT cycle and the auxiliary steam cycle are very distinct. If the boiler and steam turbine are bypassed, the OCGT can operate in a peaking role with rapid changes in output, but with a lower overall plant efficiency. Due to thermal stresses, the boiler and steam turbine require more moderate ramping conditions and a limited number of cold starts per year.
- In our model we treat these components separately as an OCGT + an auxiliary Steam Turbine Generator (STG). The output from the STG is always limited by the amount of waste heat that is available from OCGT exhaust in any hour.



For a 2x1 configuration it is assumed that a CCGT consists of

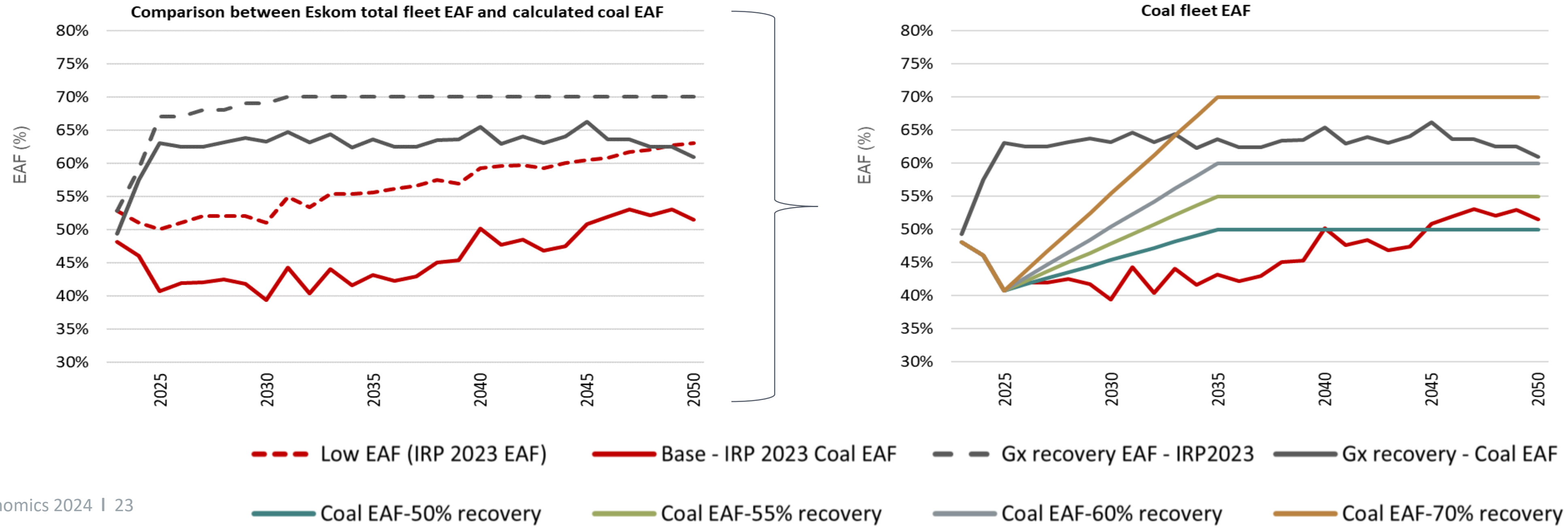
- 2 x 540 MW OCGT
- 1 x 460 MW steam turbine

HRSG = Heat Recovery Steam Generator

ANNUAL AVERAGE COAL EAF USED AS BASIS FOR THE MODELLING

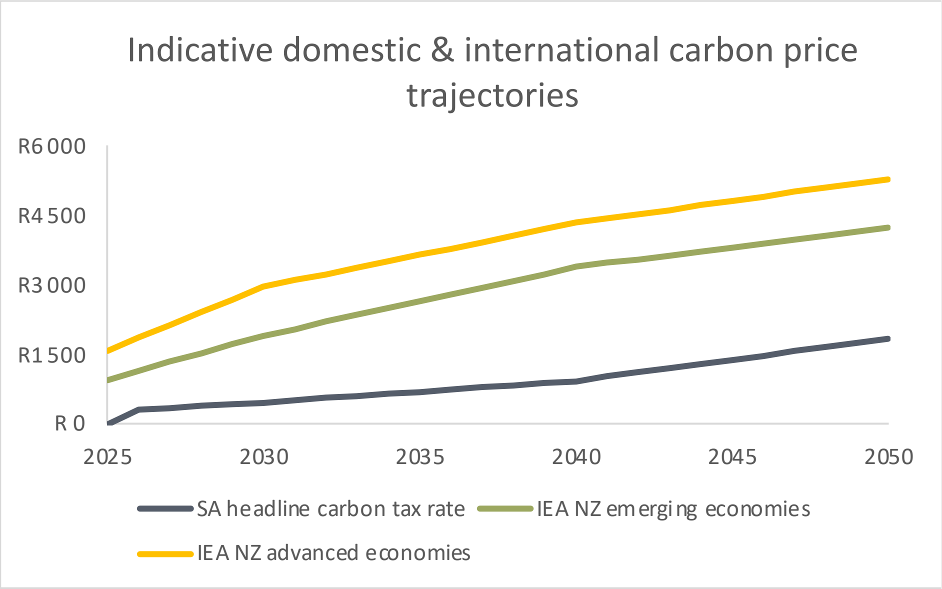
THE ESKOM COAL FLEET EAF IS MUCH LOWER THAN TOTAL FLEET EAF (DUE TO HIGH AVAILABILITY OF OTHER PLANTS)

- The EAF profile for this work is based on the Low EAF (IRP 2023 EAF) for Horizon 1 and the Reference EAF for Horizon 2.
- The annual average coal EAF is calculated from the total Eskom plant EAF provided in IRP 2023 by estimating and removing the contribution from the nuclear and peaking stations. The coal EAF is always lower than the total fleet EAF which includes peaking plants with availability over 95%, and nuclear (higher EAF once life extension complete). A comparison between total fleet EAF and coal EAF is provided in the figure below (left).
- Given the low coal EAF assumption we also tested differing levels of recovery in the coal EAF by 2035, ranging between 50% and 70%, as shown in the figure (right).



DECARBONIZING THE POWER SECTOR – AN ABSOLUTE ECONOMIC IMPERATIVE

- The Paris Agreement and the increasing impact of climate change is resulting in a global climate mitigation agenda which is starting to reflect in product and financial markets, impacting the economic competitiveness of countries.
- South Africa has a highly carbon intensive economy and is therefore particularly vulnerable
- As in most countries, the SA power sector holds the key to the decarbonisation of the South African economy:
  - Power sector carbon intensity is embedded in the rest of the economy, given that electricity is an input to economic activity
  - Electrification, on its own, is an important mitigation option for other sectors (transport, industry)
  - Given South Africa's exceptional endowment of renewable energy resources the power sector holds the predominance of it least or no-cost mitigation options. The power sector will therefore need to decarbonise faster than the rest of the economy.



The figure above suggests that the imposition of the domestic carbon tax at its headline rate may still leave the economy vulnerable to net zero carbon pricing in export markets thereby putting its export at risk.

ACHIEVING SOUTH AFRICA'S CLIMATE POLICY OBJECTIVES

THE IMPLICATIONS OF THE NATIONALLY DETERMINED CONTRIBUTION, NET ZERO GOAL AND CARBON TAX

The power sector has a critical role in enabling the country to achieve its Nationally Determined Contribution (NDC) target range of 350 – 420Mt by 2030 cost effectively; and in reaching zero emissions by 2050. Further, South Africa's carbon tax is anticipated to apply to the electricity sector from January 2026 (DMRE, New Tech assumptions IRP, 2023).

We explore alignment with South Africa's climate mitigation policy in three ways in the modelling, by:

1. considering how all scenarios fare against an appropriate NDC range for the power sector and possible trajectories to zero
2. imposing a price on carbon in line with the carbon tax headline rate (two scenarios)
3. imposing a binding emissions trajectory to net zero in 2050 (two scenarios)

The meaning of Net Zero by 2050 in the SA power sector

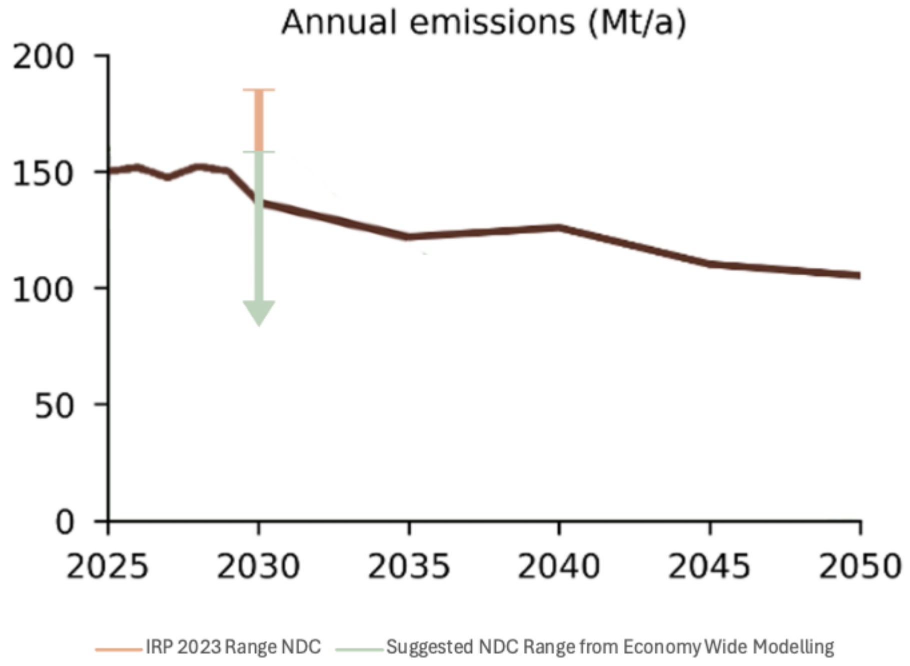
- South Africa has indicated an economy-wide policy goal of Net Zero by 2050
- From the Net Zero point onwards, any residual emissions are offset by carbon removals.
- Given the clear cost effectiveness of mitigation in the SA power sector, it will be cheaper to mitigate than to offset residual power sector emissions with expensive carbon removals. Therefore, a Net Zero goal for SA is assumed to mean a 'zero' emissions goal for the power sector by at latest 2050.
- Claimed net zero goals are only credible if associated with a commensurate emissions trajectory to the net zero point.

For a fuller discussion of these points, see Meridian Economics:
'Achieving Net Zero in SA's power sector' and 'The meaning of Net Zero for SA and its power sector'

DEFINING AN APPROPRIATE NDC RANGE FOR THE POWER SECTOR

Whilst South Africa has committed to an NDC emissions range for the entire economy in 2030, sector-level contributions to this range have not yet been formally determined in policy (in the Sectoral Emissions Targets of the forthcoming Climate Change Act.)

- The draft IRP2023 claims an NDC range of 160-180Mt for the power sector (IRP 2023 Figure 21). According to the modelling underpinning the economy-wide NDC range (the energy model of the Energy Systems Research Group, University of Cape Town), this is likely too high, given the cost-effective mitigation options available to the sector relative to the rest of the economy. For example, in the World Bank's South African Country Climate and Development Report (CCDR), 160Mt is associated with the upper limit of the NDC range. South Africa's JETP IP suggests the upper limit to be closer to 125Mt.
- Meridian's re-constructed* IRP emissions curve (chart on right) achieves ~125Mt in 2030, which seems comfortably within a potential upper limit contribution.
- To contribute towards the South Africa achieving the lower limit of its NDC cost-effectively and improve the country's resilience to international carbon pricing of exports, the power system emissions reduction by 2030 will have to be greater than suggested by the IRP2023.
- Each subsequent 5-year NDC must be progressively more ambitious, implying a declining emissions trajectory over time. Trajectories to zero are considered in a future slide.



*This emissions trajectory is determined through a least-cost dispatch of the generation capacity in the IRP reference pathway using our assumed emissions factors (see technical appendix)

IMPOSING A CARBON PRICE

TO REFLECT BOTH DOMESTIC POLICY BUT ALSO THE IMPACT OF INTERNATIONAL CARBON PRICING

- To reflect South Africa's carbon tax policy together with the future impact of international carbon pricing, a carbon price is applied in some scenarios to all power sector CO_2 emissions from 2026 – 2050
- This price follows the headline tax rate as interpreted by the DMRE (New Tech assumptions IRP, 2023):
  - The carbon tax regime includes an arrangement which currently fully offsets the impact of the tax for electricity generation. However, Treasury has acknowledged the need to reconsider this concession on power users, with electricity offsetting currently set to expire at the end of 2025.
  - A suite of exemptions from the headline carbon tax rate is included for all sectors. Treasury has indicated that these will reduce from 2026.
  - The SA carbon tax headline rate is significantly lower than projected international carbon prices in other countries with net zero targets. Therefore, using the full headline rate is a conservative estimate of the level of carbon pricing which will likely be imposed on South African products in many of its export markets. Ultimately, electricity will be subjected to a carbon price, domestically and internationally.
- For the carbon price scenarios the IRP 2023 coal retirement schedule is replaced by a faster coal retirement schedule to accommodate the faster power system decarbonisation that results.

IMPOSING BINDING EMISSION TRAJECTORIES TO ZERO

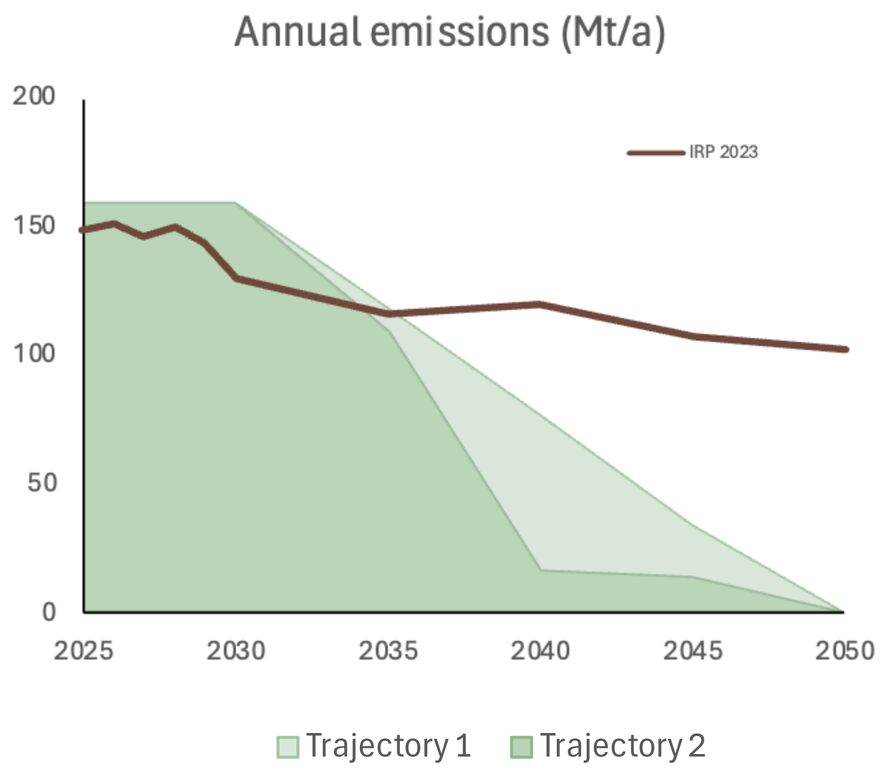
TWO POSSIBLE TRAJECTORIES TO ZERO ARE CONSIDERED

Trajectory 1: A straight line, drawn from the top of the power sector NDC range, 160 Mt in 2030, to zero in 2050

- This is an optimistic trajectory: It starts at a likely upper NDC range limit and is not derived from an economic allocation of emissions space across the economy.

Trajectory 2: The reference case from the ESRG's modelling for the World Bank SA CCDR, this trajectory is derived from apportioning a 9 GT carbon budget across the economy

- This trajectory also aligns with a likely upper NDC range limit, but drops more rapidly in the 2030s as the coal plants close by 2040.
- A target of "All coal plants off by 2040" aligns with the IEA's observations of what is required in terms of coal power closure in emerging economies for global net zero.



An independent IRP (Results)

NAVIGATING THE SCENARIOS EXPLORED

REAL-WORLD CONSTRAINTS ARE ADDED INCREMENTALLY TO THE THEORETICAL LEAST COST SYSTEM TO REVEAL THEIR IMPACT

- The following series of dashboards presents the optimal technology capacity expansion and power generation over time for the power system under different assumptions of technology costs and sequentially added real-world constraints.
- The scenarios considered are as follows:

1. Unconstrained **IRP 2023** - Using cost assumptions from the IRP 2023 and the emerging plan to 2030 we replicate construction of the reference scenario for Horizon 2 (2031 – 2050). This reveals that the published IRP reference scenario has been constrained i.e. build limits have been applied to technologies, specifically Wind and Solar

All subsequent scenarios use the Meridian revised technology cost assumptions to compare alternate power plan scenarios

2. **Unconstrained least cost** – Using revised, realistic base case cost assumptions the optimal least cost power system is determined, minimising future load shedding. New build capacity is added as soon as lead times and grid limitations (imposed until 2034) allow. This theoretical power system plan is unbounded by other real-world constraints, but provides a useful indication of the nature of a lowest cost power system.
3. **Realistic gas contracting** – flexible dispatchable capacity (primarily OCGT) can burn diesel, gas, or in future clean fuels (green hydrogen, methanol etc). Optimal dispatch of this capacity results in highly intermittent, unpredictable monthly and annual offtake. Gas (LNG) cannot be contracted on this basis. Minimum annual offtake and minimum monthly utilisation are imposed to model contractual realities.
4. **Realistic RE build scenarios** – four different rates of build for solar and wind capacity are modelled. Build progresses linearly through each year
5. **Test Coal EAF impact** – Base case coal EAF is matched to IRP assumption (42% average to 2030). We test recovery to 50%,55%,60%,70% by 2035
6. **Test RE cost learning** – Faster, Slower cost declines for solar, wind and batteries are tested using the base case RE build limits
7. **Test decarbonization impact** – Four decarbonisation scenarios are developed using two accelerated coal decommissioning profiles combined with either power sector emissions trajectories to net zero by 2050, or by applying the National Treasury carbon tax as an internalised price on carbon.

IRP2023 | Unconstrained Least Cost | Realistic Gas Contracting | Realistic RE build scenarios | Test Coal EAF Impact | Test RE Cost learning | Test decarbonization impact

Banner indicates the sequence in which constraints are applied

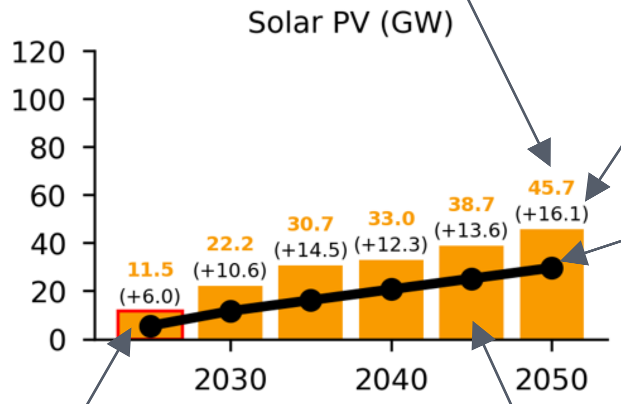
HOW TO READ THE CHARTS

Name of scenario being compared will be stated here. Where costs or constraints are not made explicit the scenario is constructed using the base case assumptions.

The six technology charts in this area compare the cumulative new capacity additions for the current scenario with the proposed plan in the IRP 2023.

The coloured number specifies the cumulative capacity in the scenario.

The bracketed black number indicates how much the scenario deviates from the IRP.



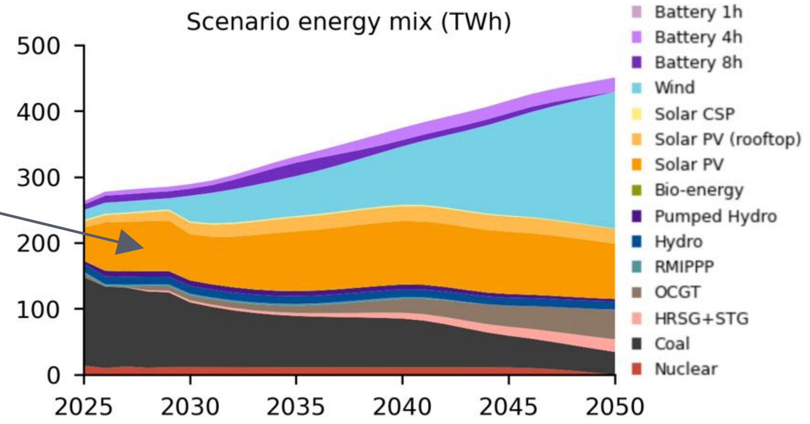
The black line represents cumulative capacity additions in the IRP.

A red border indicates that build constraints have been reached for that period.

The coloured bars represent cumulative capacity additions for the scenario.

The four charts in this area compare the energy mix and fuel consumption of the IRP 2023 on the left with the current scenario on the right.

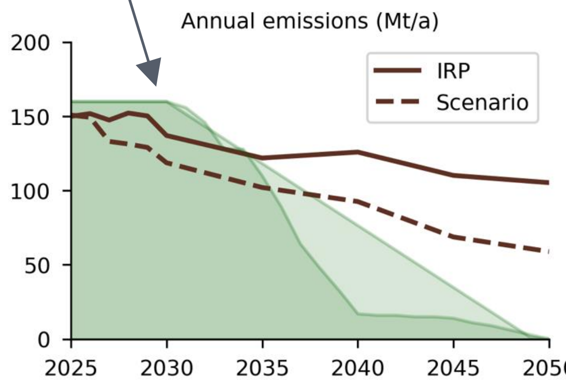
These colours correspond with the six technologies in the capacity charts on the left of the page. For the other technologies, refer back to the legend on right hand side of this slide.



This table indicates how the current scenario deviates from the IRP in respect of load shedding, present value (PV) of costs, and cumulative emissions. For example:

- Load shedding of -66.9% indicates the scenario eliminates 66.9% (49TWh) of the IRP load shedding
- PV of costs of -2.1% indicates that the system cost of the scenario is 2.1% lower than the IRP
- Present value cost difference between the scenario and the IRP are shown in the bottom row

This chart compares the emissions trajectories of the IRP and the current scenario against the two net zero trajectories



Load shedding	PV of costs 2025-2050	Cumulative Emissions
-66.9% -49 TWh	-2.1%	-19.4% -631 Mt
(-4289 R'bn)	(-79 R'bn)	(-183 R'bn)

SCENARIO GUIDE

Scenario	Slide	Optimised?	Costs	RE Build Constraints	Gas contracting constraints	Coal EAF by 2035	NZ by 2050	Carbon emissions cost
IRP Costs, Unconstrained		2031 - 2050	IRP	None	None	IRP	No	Reported only
IRP 2023 for comparison	41 -	No	Per scenario compared	Build per IRP plan	None	IRP	No	Reported only
Unconstrained Least Cost		2025 - 2050	Base Case	None	None	IRP	No	Reported only
Realistic Gas Contracting		2025 - 2050	Base Case	None	Realistic	IRP	No	Reported only
Targeted Solar Intervention		2025 - 2050	Base Case	Targeted Solar	Realistic	IRP	No	Reported only
Optimistic RE Build		2025 – 2050	Base Case	Optimistic	Realistic	IRP	No	Reported only
Base Case RE Build		2025 – 2050	Base Case	Base Case	Realistic	IRP	No	Reported only
Pessimistic RE Build		2025 – 2050	Base Case	Pessimistic	Realistic	IRP	No	Reported only
Base Case (RE Build, RE Costs, EAF)		2025 - 2050	Base Case	Base Case	Realistic	IRP	No	Reported only
Coal EAF Recovers to 50% by 2035		2025 - 2050	Base Case	Base Case	Realistic	Recovery to 50%	No	Reported only
Coal EAF Recovers to 55% by 2035		2025 - 2050	Base Case	Base Case	Realistic	Recovery to 55%	No	Reported only
Coal EAF Recovers to 60% by 2035		2025 - 2050	Base Case	Base Case	Realistic	Recovery to 60%	No	Reported only
Coal EAF Recovers to 70% by 2035		2025 - 2050	Base Case	Base Case	Realistic	Recovery to 70%	No	Reported only
Base Case (RE Build, RE Costs)		2025 - 2050	Base Case	Base Case	Realistic	IRP	No	Reported only
Base Case RE Build, Stress RE Costs		2025 - 2050	Stress	Base Case	Realistic	IRP	No	Reported only
Base Case RE Build, Likely RE Learning		2025 - 2050	Likely Learning	Base Case	Realistic	IRP	No	Reported only
Targeted Solar Intervention		2025 - 2050	Base Case	Targeted Solar	Realistic	IRP	No	Reported only
Targeted Solar, Price on Carbon		2025 - 2050	Base Case	Targeted Solar	Realistic	IRP	No	Minimised and reported
Targeted Solar, NZ 2050		2025 - 2050	Base Case	Targeted Solar	Realistic	IRP	Yes	Reported only
Targeted Solar, Price on Carbon (Coal off by 2040)		2025 - 2050	Base Case	Targeted Solar	Realistic	IRP	No	Minimised and reported
Targeted Solar, NZ 2050, 9 GT Budget		2025 - 2050	Base Case	Targeted Solar	Realistic	IRP	Yes	Reported only

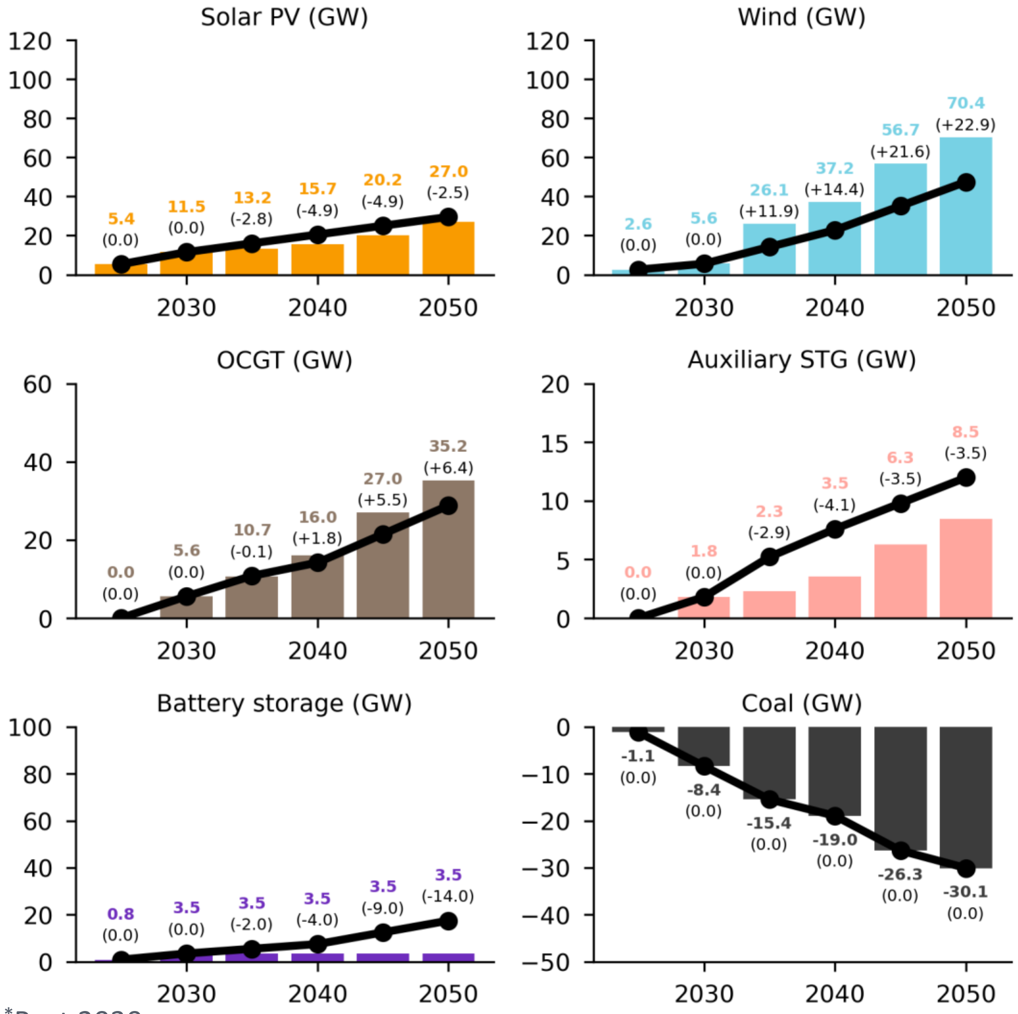
REPLICATING THE IRP 2023

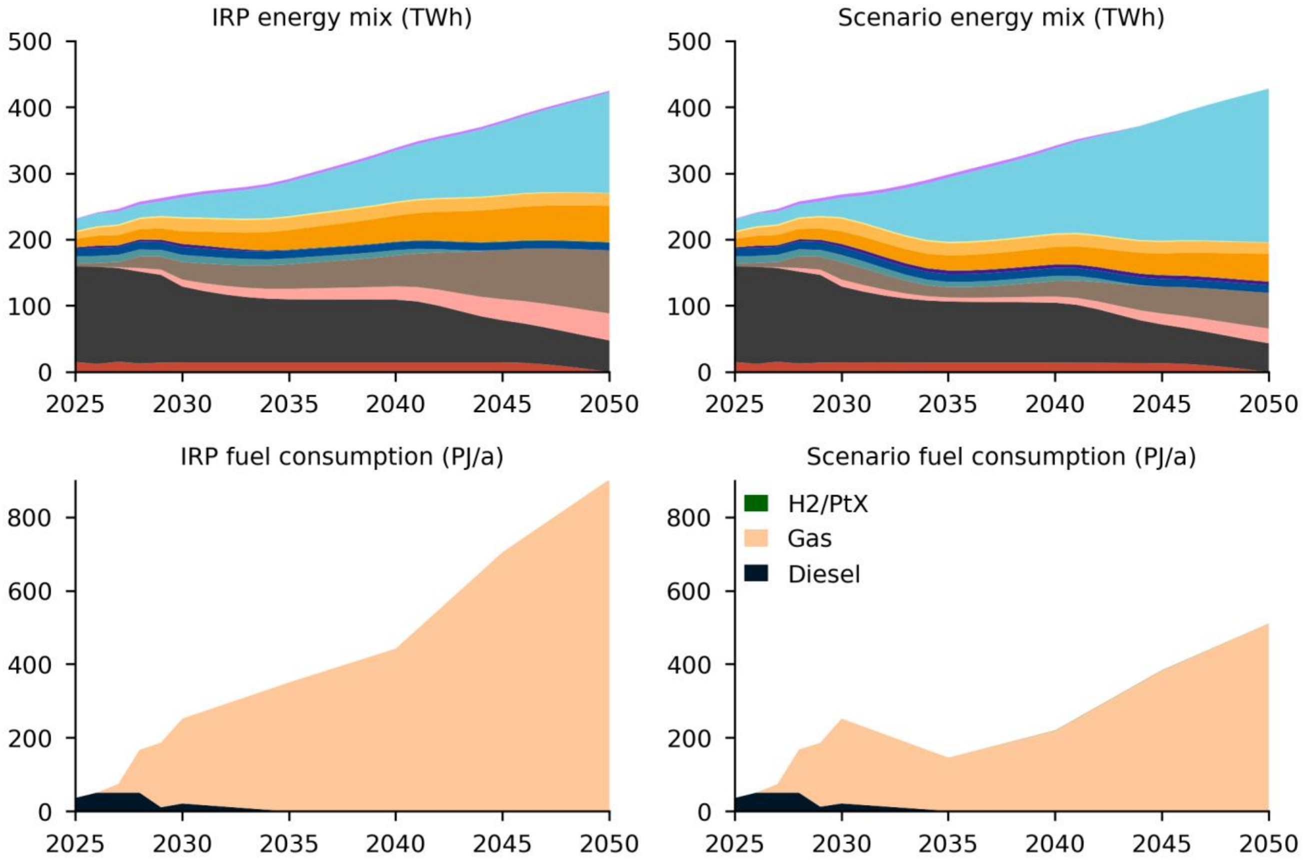
IS THE IRP 2023 A LEAST COST PLAN BASED ON ITS OWN PUBLISHED COST ASSUMPTIONS?

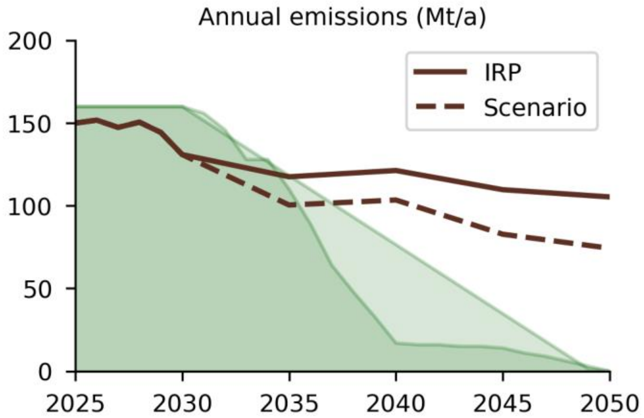
- In this scenario we use the “supply side options currently in development by both government and the private sector” as implemented for Horizon 1 to 2030 in the IRP 2023, followed by an unconstrained least cost optimised power system plan from 2031 – 2050 based on the IRP 2023 technology cost assumptions
  - For purposes of this validation scenario all capacity contemplated in the emerging plan is assumed to come online (including the REIPPPP and RMIPPPP projects now known to have failed)
  - IRP 2023 discloses no build rate constraints applied to different technologies and describes the reference pathway as “least cost…without any restrictions.”
    - This validation scenario should therefore replicate the IRP 2023 emerging plan and the reference pathway for Horizon 2.
- Clearly from the next slide, an unconstrained least cost power system based on the IRP 2023 cost assumptions when compared to the published plan would
  - implement far more wind (+14GW by 2040, +23GW by 2050) and rely far less on gas
  - Implement even less solar (due to the unrealistically high solar cost assumption) than the already minimal capacity envisaged
  - be much lower cost (6.5% cost saving)
  - generate significantly less carbon emissions (-400Mt)
- This analysis would indicate that artificial, undisclosed constraints have been applied in generating the reference pathway
- It is further notable that despite the unreasonably high-cost assumptions for solar, wind and batteries and the exceptionally low-cost assumption for nuclear power (received from vendors), no nuclear capacity features in this unconstrained analysis or the IRP 2023 reference pathway.
  - No nuclear capacity is built in any scenarios we investigated
  - The only scenario with nuclear capacity in the IRP 2023 is based on the exclusion of all thermal technologies (other than CSP)

IRP COSTS, UNCONSTRAINED*

Cumulative new capacity from 2024







Load shedding	PV of costs 2025-2050	Cumulative Emissions
0.0% -0 TWh	-6.5%	-12.9% -409 Mt
(- 0 R'bn)	(-276 R'bn)	(-118 R'bn)

*Post 2030

THEORETICAL, UNCONSTRAINED, LEAST COST POWER

WHERE SHOULD THE POWER SYSTEM BE HEADING IN THE ABSENCE OF CONSTRAINTS?

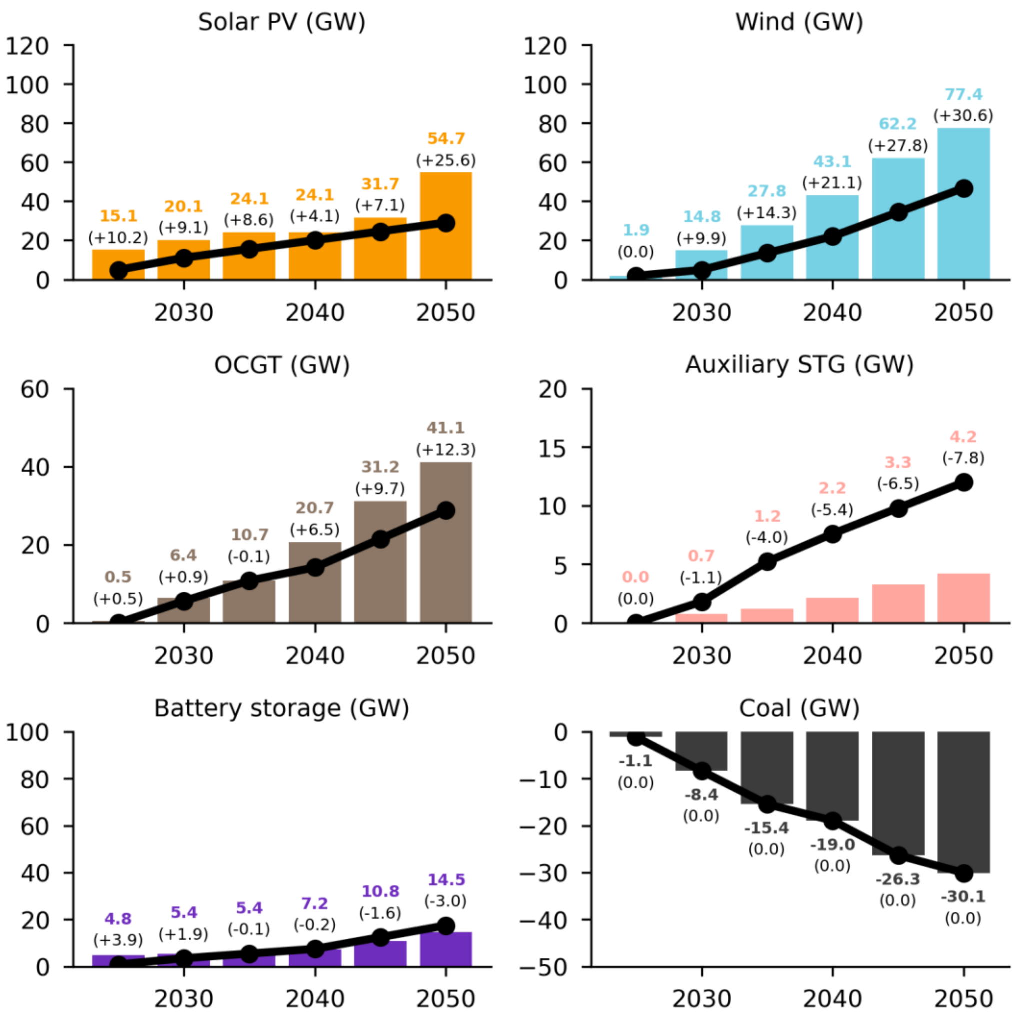
For this scenario and all subsequent scenarios:

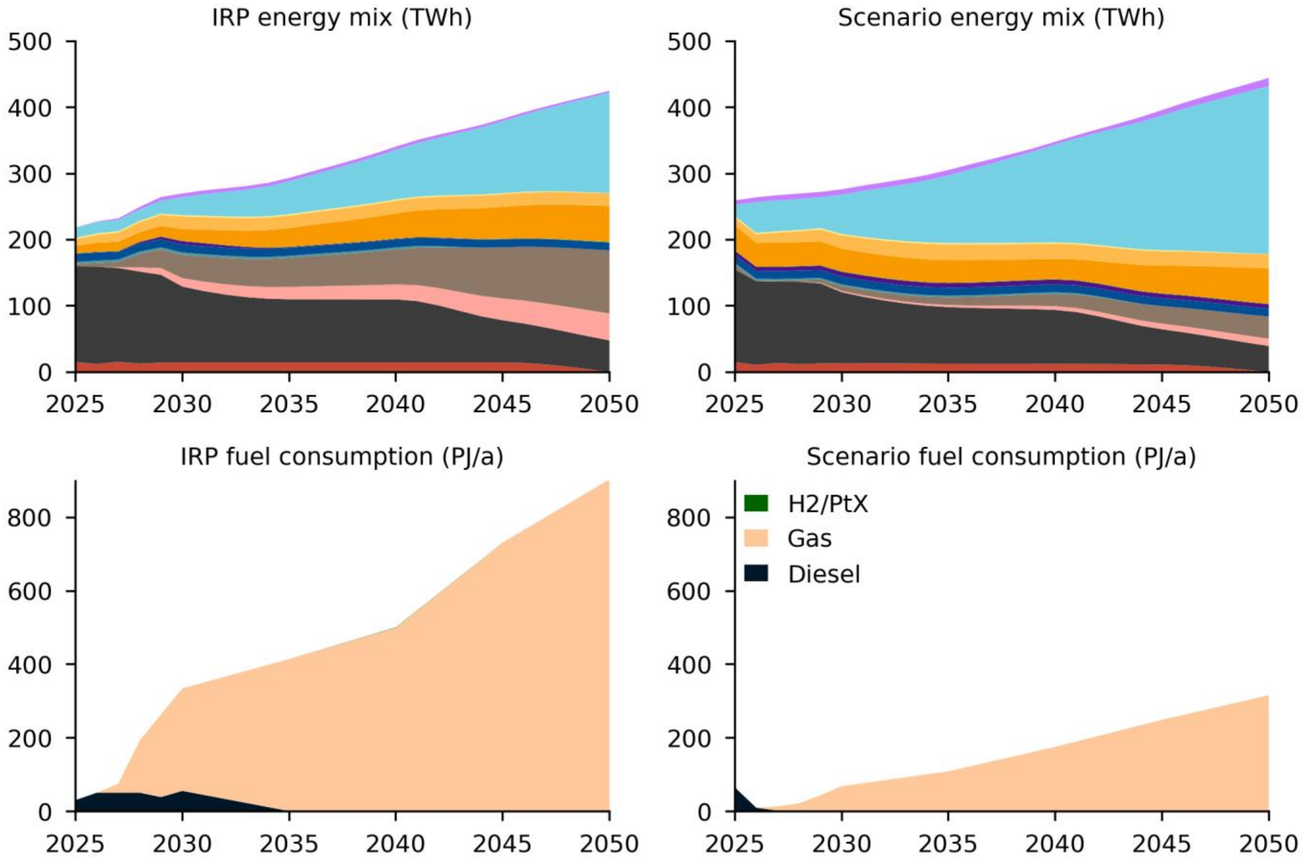
- *Technology costs are not based on the published IRP 2023 assumptions but are independent estimates. These cost assumptions are disclosed in the technical appendix.*
- *Comparison to the IRP 2023 plan for purposes of calculating load shedding, system cost, emissions and new capacity differences takes account of the failed projects relied upon in the emerging plan by removing them and their associated costs from the IRP 2023 plan.*

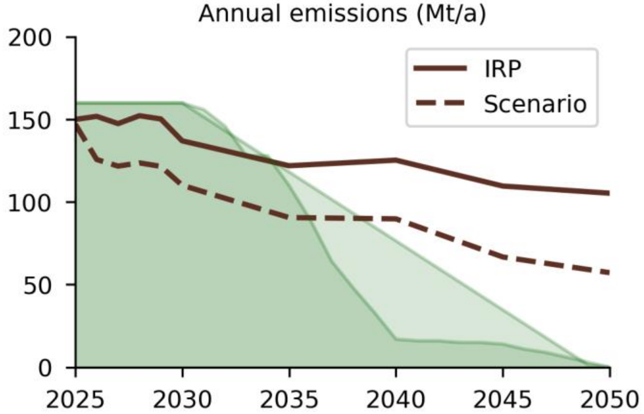
- The unconstrained scenario based on revised base case technology cost assumptions is 11% lower cost than IRP 2023 and entirely eliminates the load shedding resultant from the Emerging Plan, with 27% less emissions to 2050.
- This unconstrained plan is based on an explosive build of renewables with commissioning of 15GW new solar by 2025, and a further 5GW by 2030. 15GW of Wind is commissioned by 2030.
- Solar with its short lead times and relative immunity from grid constraints is the only technology able to ramp fast enough to impact load shedding in the short term.
- Whilst 15GW is an unrealistic build in 18 months, an intervention could get close to this number (5GW of panels were imported in 2023).
- Energy for this power system plan comes overwhelmingly from renewables, with gas-fired flexible generation operating predominantly in peaking mode.

UNCONSTRAINED LEAST COST

Cumulative new capacity from 2024







Load shedding	PV of costs 2025-2050	Cumulative Emissions
-99.8% -73 TWh	-11.0%	-27.3% -887 Mt
(-6668 R'bn)	(-418 R'bn)	(-258 R'bn)

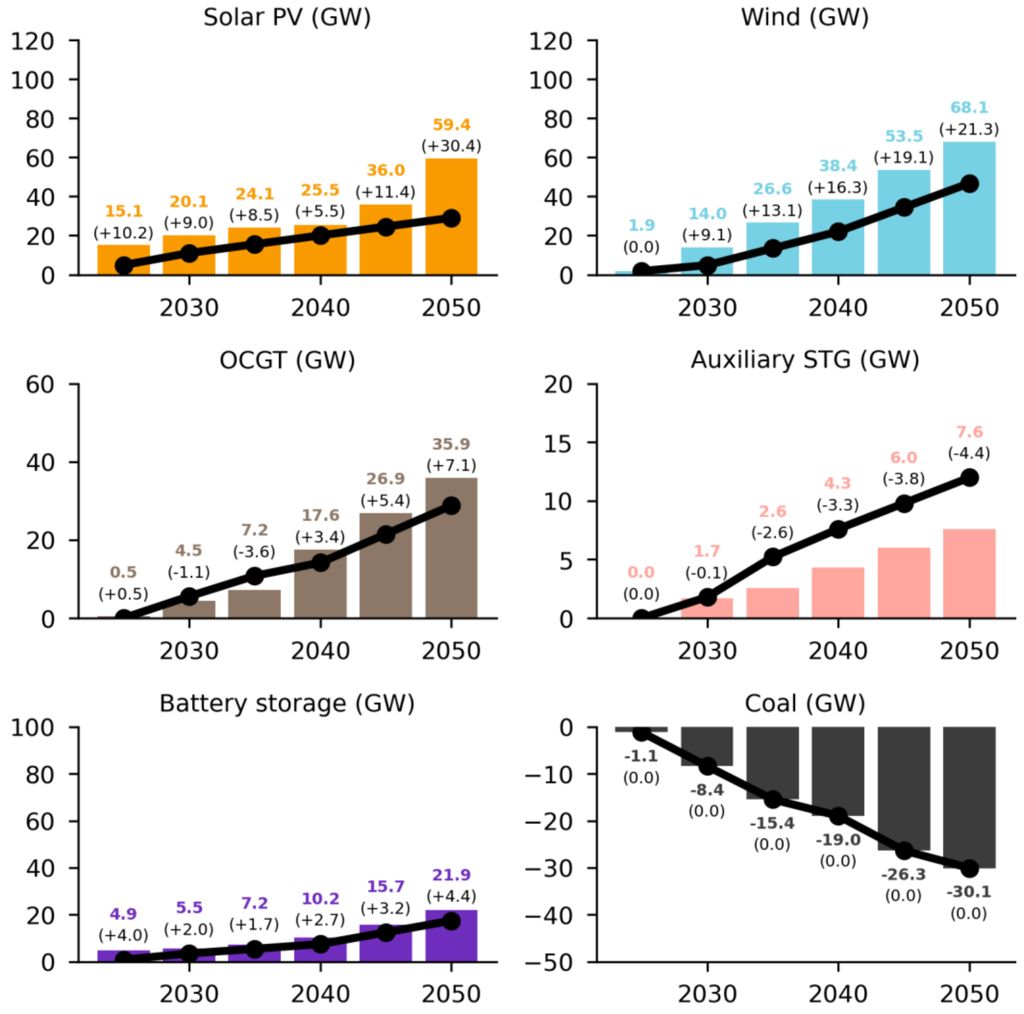
PRACTICAL CONSIDERATIONS FOR USE OF GAS (LNG)

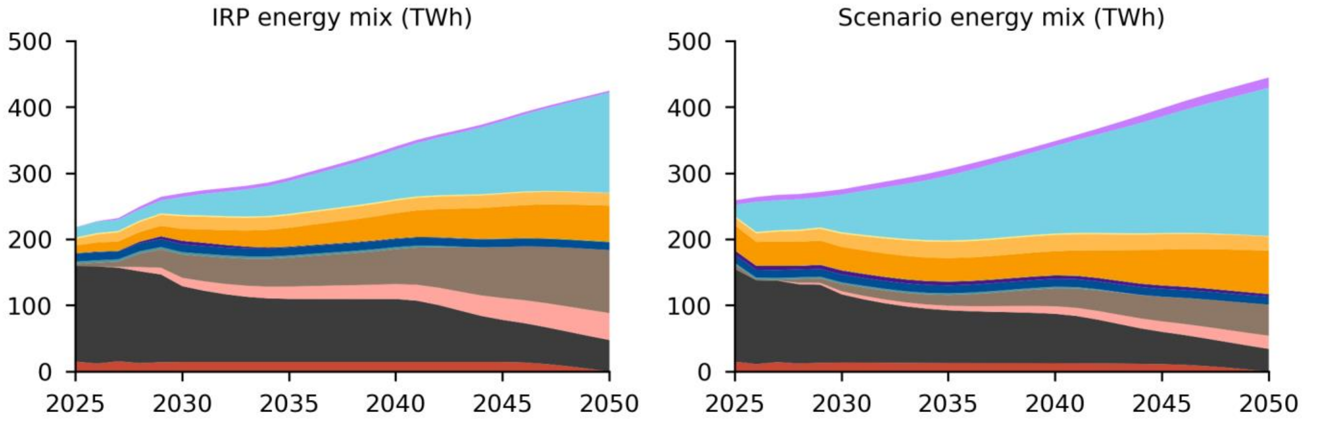
GAS IS A CHEAP FUEL, PROVIDED OFFTAKE IS SIGNIFICANT, CONTINUOUS AND LONG TERM

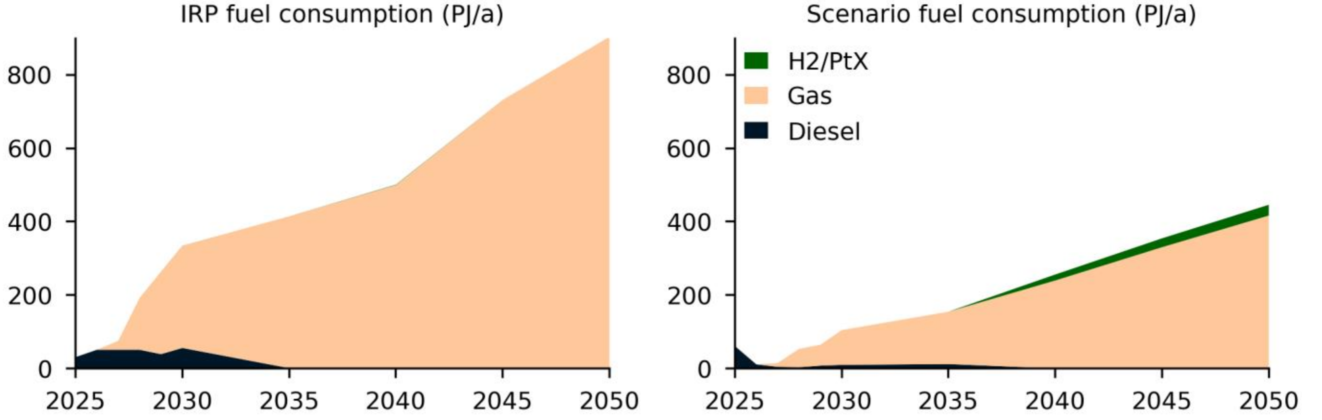
- The unconstrained least cost scenario relies on gas exclusively to fuel new flexible capacity as it is the cheapest fuel
  - We assume diesel and future green fuels are treble the price of gas and have used the IRP assumption for gas at $15/GJ
- However, gas (LNG) is subject to contracting constraints that require consistent offtake at sizeable volumes.
  - Gas is thus ill-suited to a peaking fuel role (low capacity factor, erratic use) and cannot realistically supply all flexible generation needs
  - A decision to use gas must be economically rational when considering realistic minimum contract commitments
- Modelling this is complex and is simplified as follows when gas forms part of a candidate pathway in our modelling:
  - Minimum annual offtake of 50PJ/year (this would barely make import infrastructure viable, but would be enough with additional industrial supply)
  - Gas-fired OCGT capacity must run with minimum MONTHLY capacity factor of 40%
  - Auxiliary STG must run with minimum MONTHLY capacity factor of 30%
- These constraints apply to gas use throughout the modelling period, but from 2040 fuel can switch to a green alternative with intermittent peaking offtake if economic to do so. It is assumed that diesel can be supplied throughout the period in a manner that supports intermittent peaking offtake.
- The economically optimal result of these real-world constraints is that a portion of the OCGT fleet runs on gas at the minimum capacity factor of 40% whilst the remainder runs very seldom and uses diesel (or switches later to green fuel). In practice machines would need to run on multi-fuels, burning gas unless stock is depleted necessitating a switch to stored diesel.
- Modelling (next slide) shows it is economic (in the absence of emissions constraints) to increase auxiliary STG capacity and use slightly more gas than would have been burned had it been available "on-tap" (as modelled in the unconstrained case)
- Greater use of gas reduces the theoretical saving against the IRP 2023 from 11% to 7% as gas replaces some coal and renewables
- These real-world constraints on gas supply are modelled in all subsequent scenarios

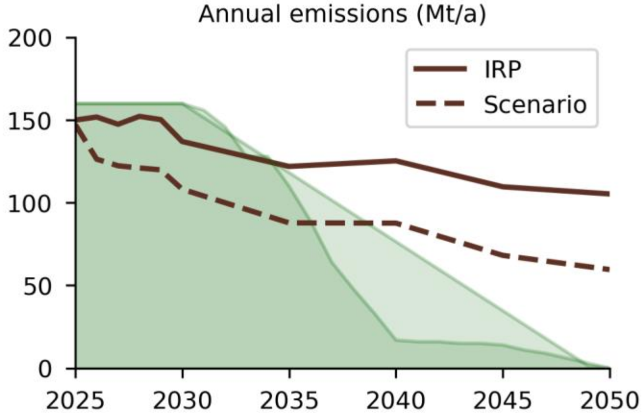
REALISTIC GAS CONTRACTING

Cumulative new capacity from 2024









Load shedding	PV of costs 2025-2050	Cumulative Emissions
-99.7% -73 TWh	-7.0%	-27.9% -906 Mt
(-6663 R'bn)	(-267 R'bn)	(-264 R'bn)

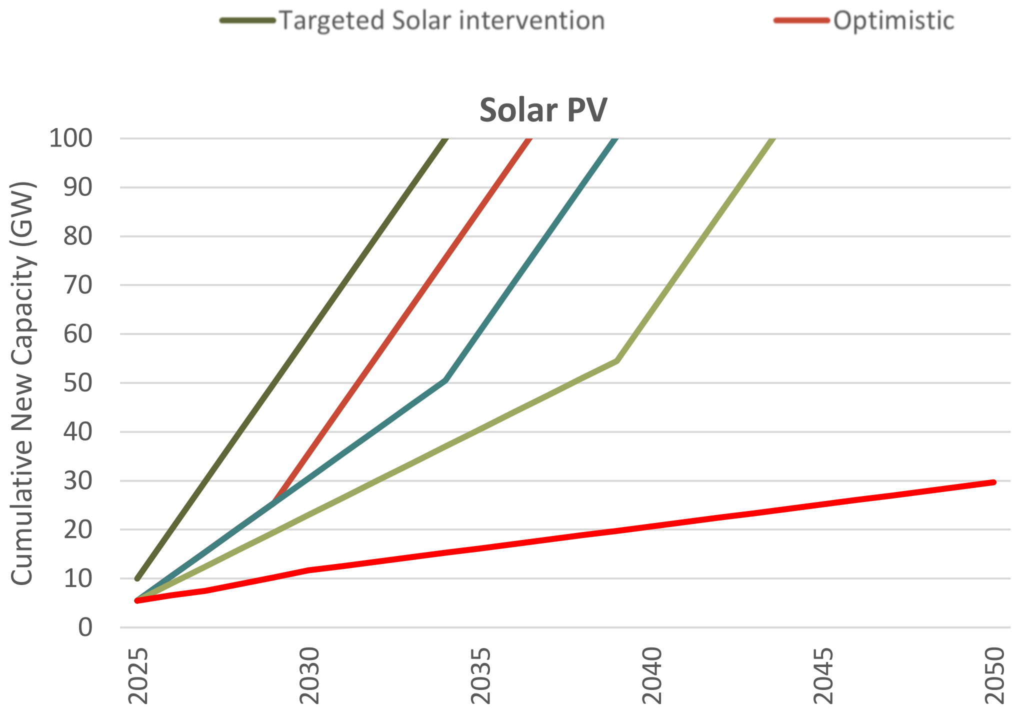
HOW FAST CAN RENEWABLES BE BUILT?

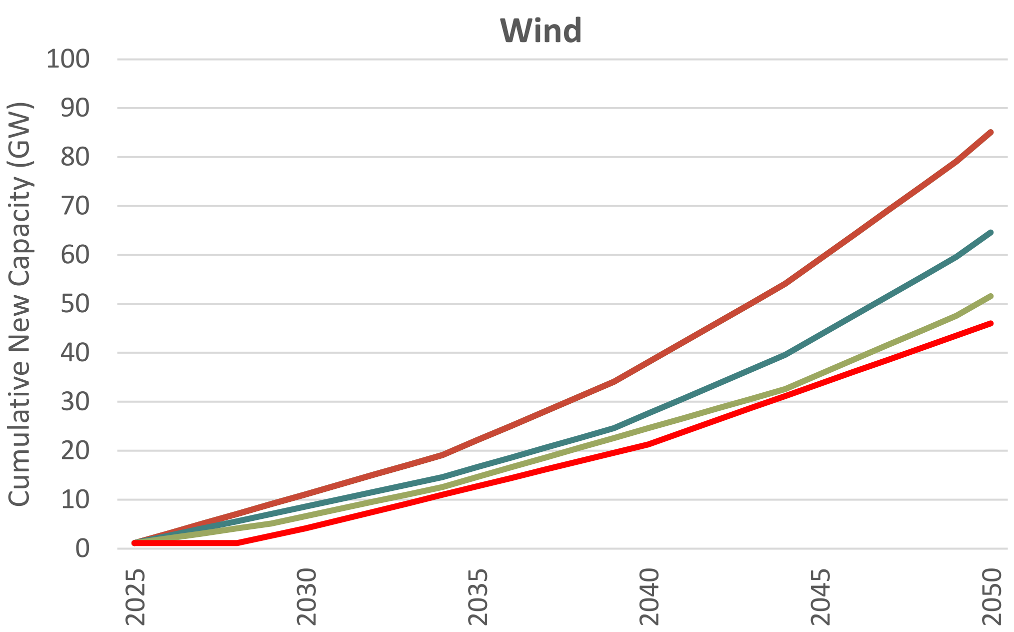
IN PRACTICE, GRID CONSTRAINTS AND LOGISTICS BARRIERS HINDER SOLAR AND WIND ROLLOUT

- The subsequent slide outlines the different build constraints applied to solar PV and wind. The constraints are far more binding on wind due to assumed challenges with grid constraints, as well as logistics (e.g. moving blades from port to site) and construction capacity.
- Without build constraints the previous slide shows 15GW of solar by 2025 would squash load shedding entirely, but this build rate is unrealistic. We explore more realistic Optimistic, Base Case and Pessimistic RE build rate scenarios that demonstrate that load shedding is still significantly addressed by faster renewables rollout rates, in contrast to the IRP 2023 assumption that renewables do not contribute to ensuring security of supply.
  - On the most pessimistic assumptions this strategy eliminates two thirds of the load shedding caused by the IRP 2023 assumed Emerging Plan.
  - With these real-world barriers on RE rollout, the 7% system cost saving in the previous slide is reduced to 1.5% - 3% by the need to burn diesel and gas in the next few years. This cost of course is dwarfed by the economic value of the avoided load shedding.
- However, from the unconstrained RE build scenario in the previous slide we know that the system can eliminate almost all load shedding rapidly if renewables could be built faster. Given the nearly exponentially increasing rate of PV construction experienced currently we therefore further investigate a Targeted (aggressive) Solar Intervention scenario that allows up to 10GW per year installed from 2025 onwards. (The policy measures to target this outcome could include Feed-in-tariffs, etc., but are left for a later discussion.)
  - If this were achieved with a total of 22GW installed PV by 2030, 80% of the 73TWh load shedding under the IRP 2023 Emerging Plan would be eliminated.
- The findings further show that if wind build remains constrained post 2040, significantly more solar and storage is economically optimal even without consideration of carbon constraints. The large gas usage inherent in the IRP 2023 is not supported economically.
- Note that all these scenarios breach net zero carbon emissions reduction trajectories (and likely future NDCs) in the 2030s with substantial power sector emissions (>50Mt/year) remaining in 2050.

ANNUAL NEW-BUILD CONSTRAINTS ON SOLAR PV AND WIND

EXPLORING DIFFERENT ASSUMPTIONS ABOUT REAL WORLD CONSTRAINTS ON THE BUILD-OUT OF RENEWABLES





Annual new build capacity (GW) Solar PV* (Utility scale and rooftop)

Scenario	by end 2025	2026 - 2029	2030 - 2034	2035 - 2039	2040 - 2044	2045 - 2049	2050 - 2054
Pessimistic	5.5	3.5	3.5	3.5	10	10	10
Base Case	5.5	5	5	10	10	10	10
Optimistic	5.5	5	10	10	10	10	10
Targeted Solar intervention	10	10	10	10	10	10	10

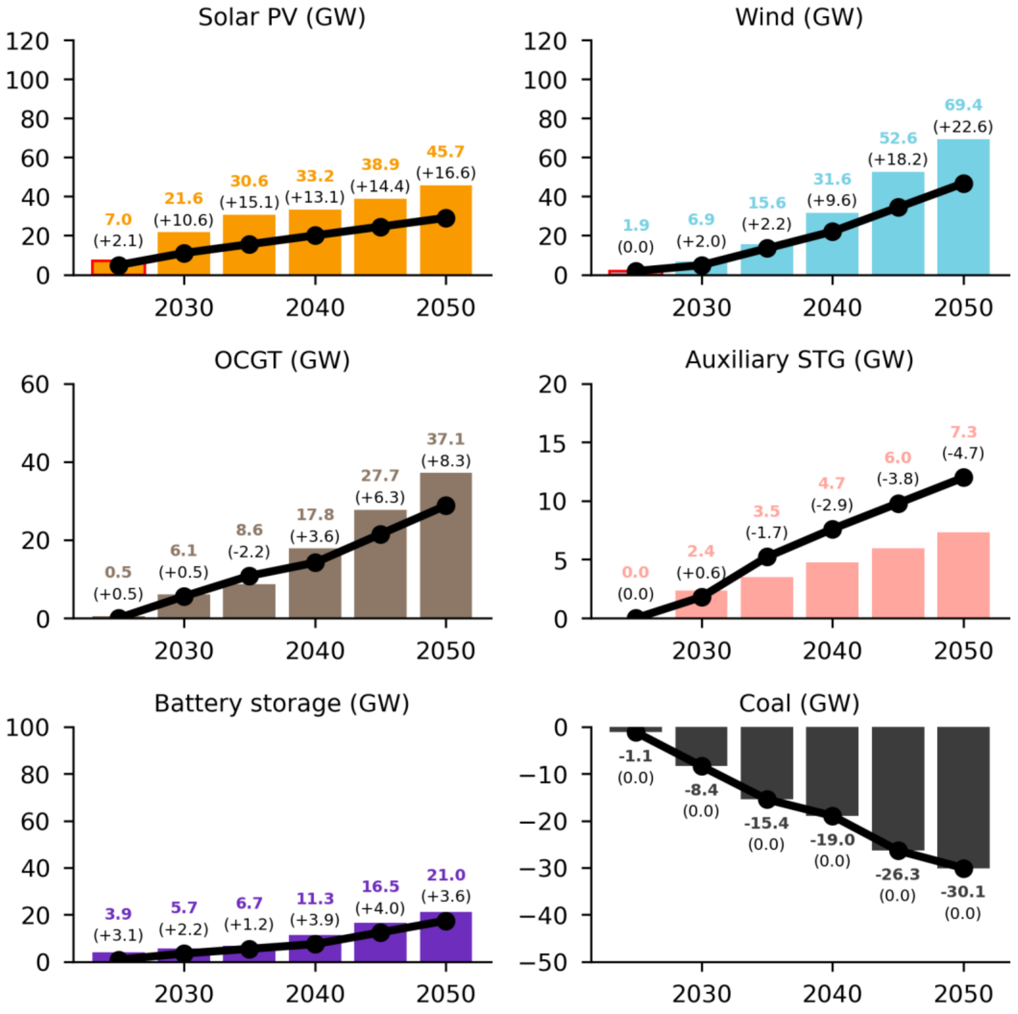
Annual new build capacity (GW) Wind*

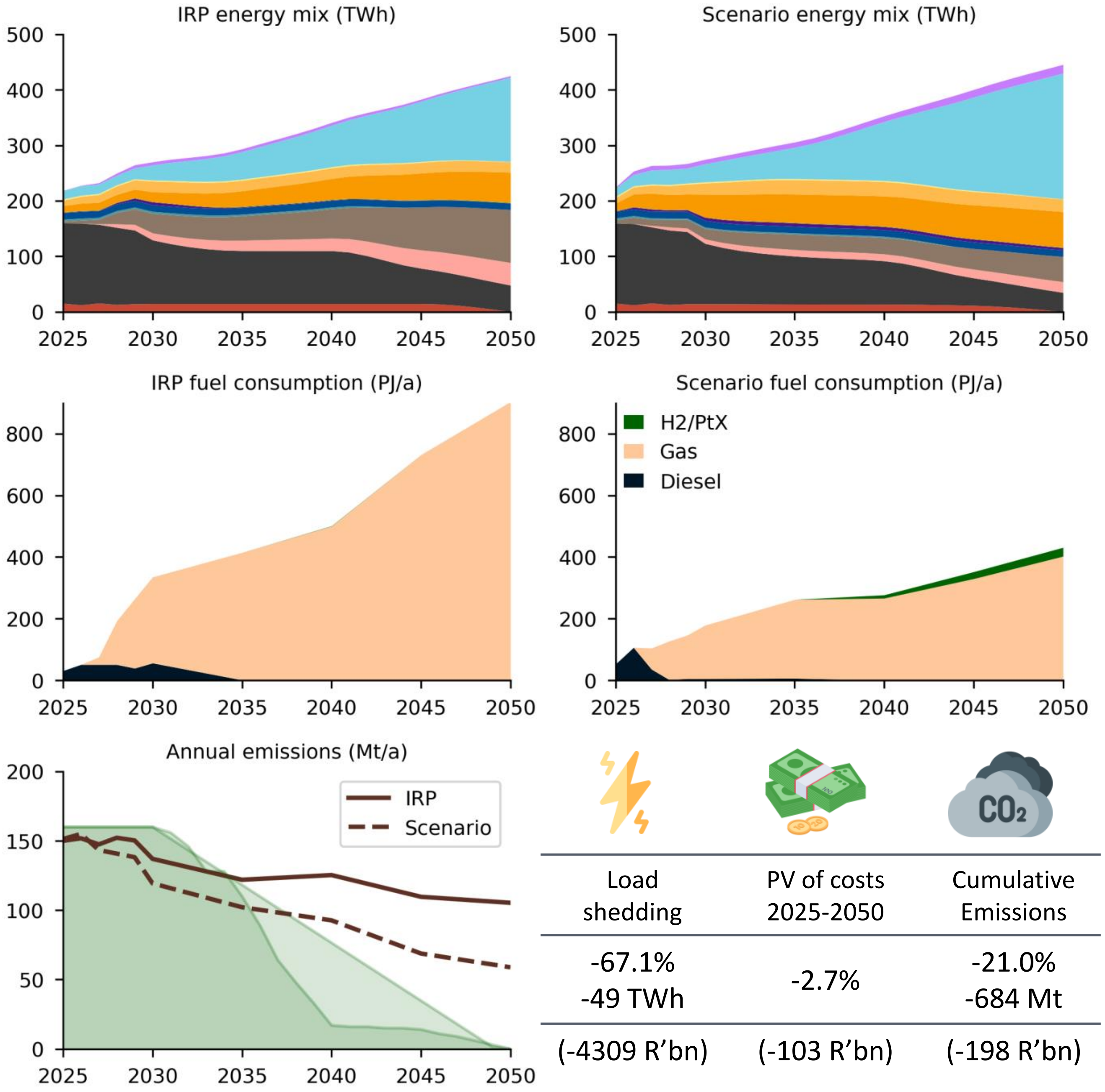
Scenario	by end 2025	2026 - 2029	2030 - 2034	2035 - 2039	2040 - 2044	2045 - 2049	2050 - 2054
Pessimistic	1	1	1.5	2	2	3	4
Base Case	1	1.5	1.5	2	3	4	5
Optimistic	1	2	2	3	4	5	6
Targeted Solar intervention	1	2	2	3	4	5	6

*Annual new build Solar PV and Wind capacity excludes in-construction REIPPPP capacity.

OPTIMISTIC RE BUILD

Cumulative new capacity from 2024

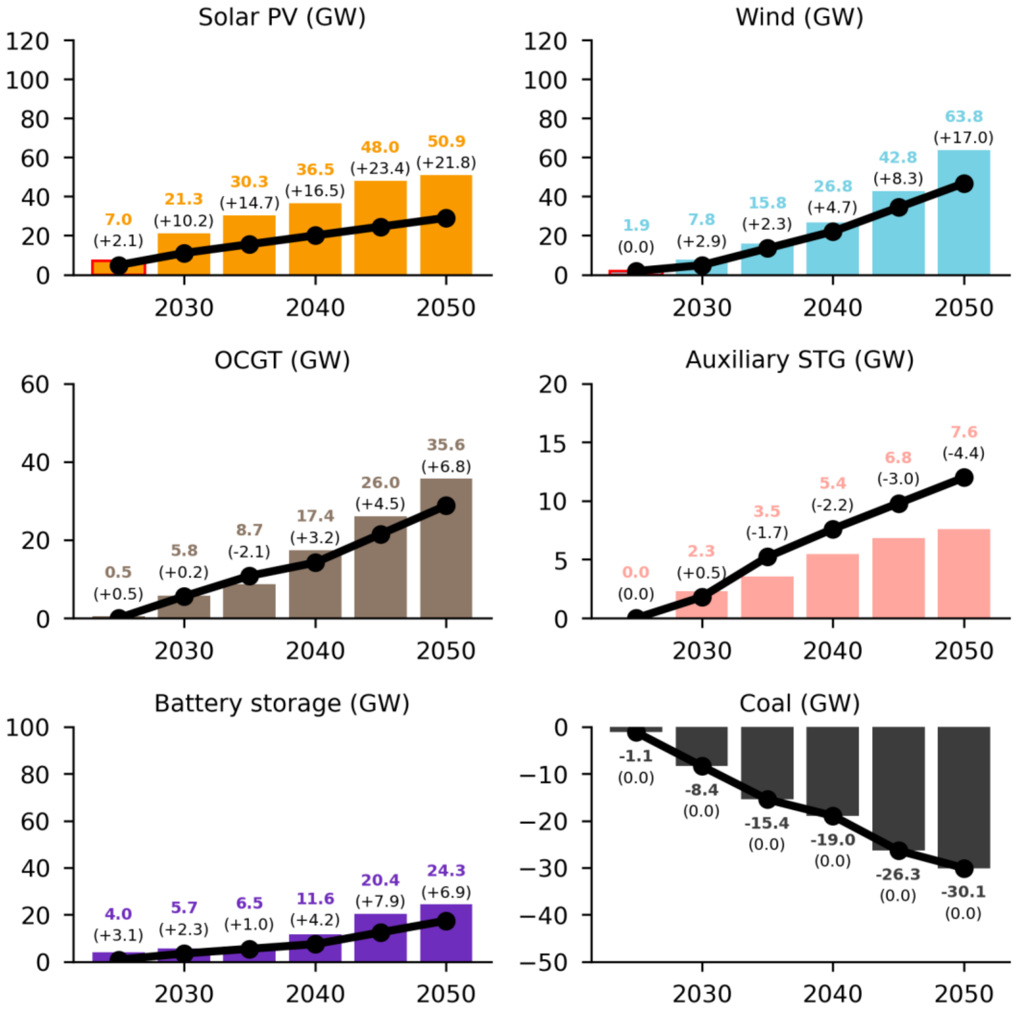


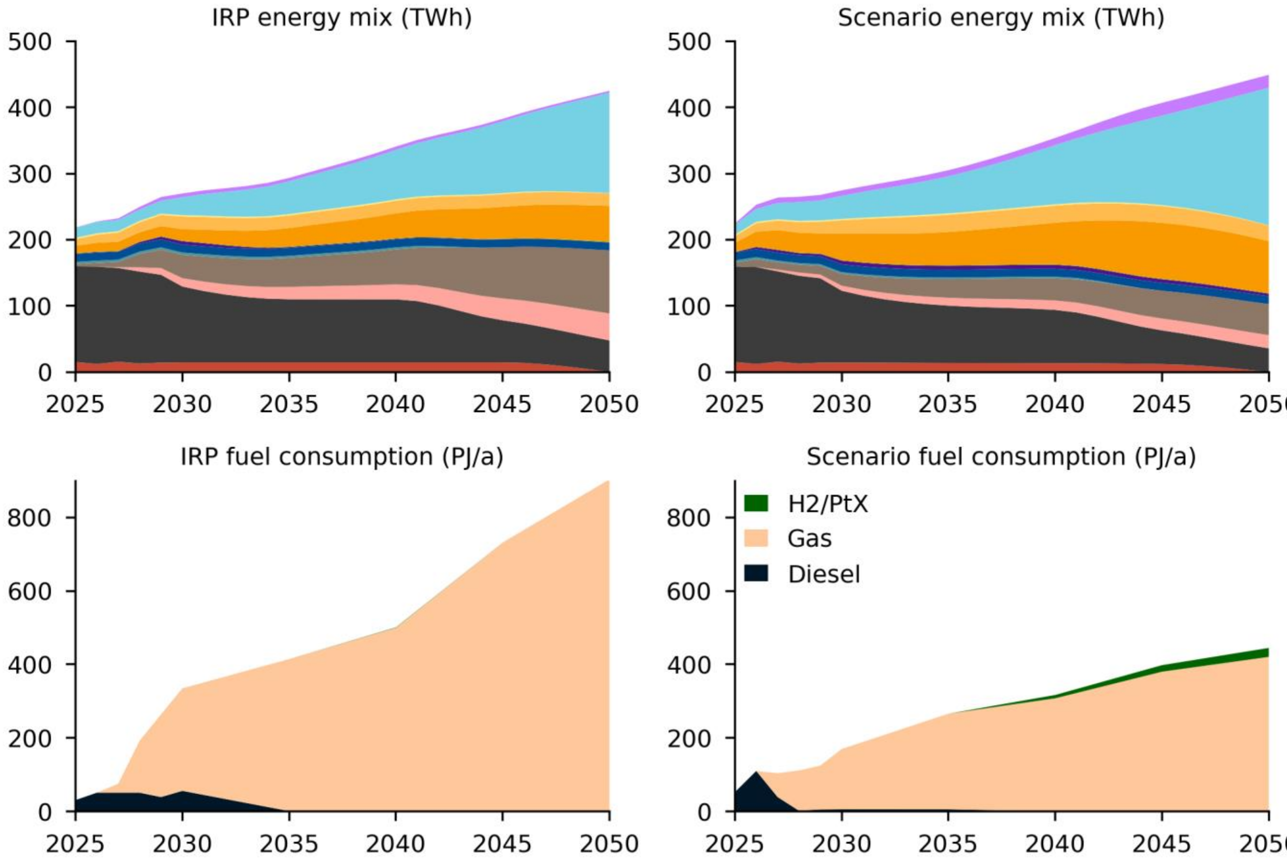


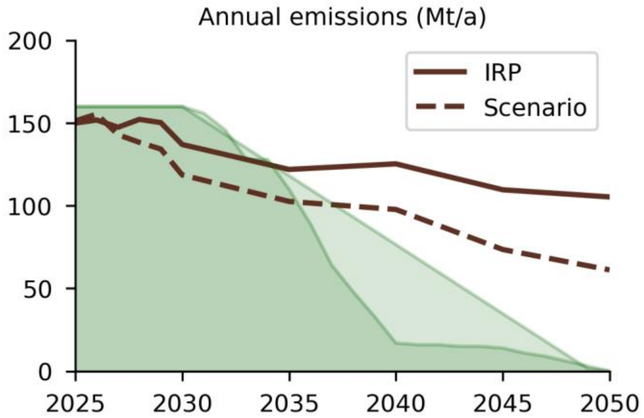
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-67.1% -49 TWh	-2.7%	-21.0% -684 Mt
(-4309 R'bn)	(-103 R'bn)	(-198 R'bn)

BASE CASE RE BUILD

Cumulative new capacity from 2024



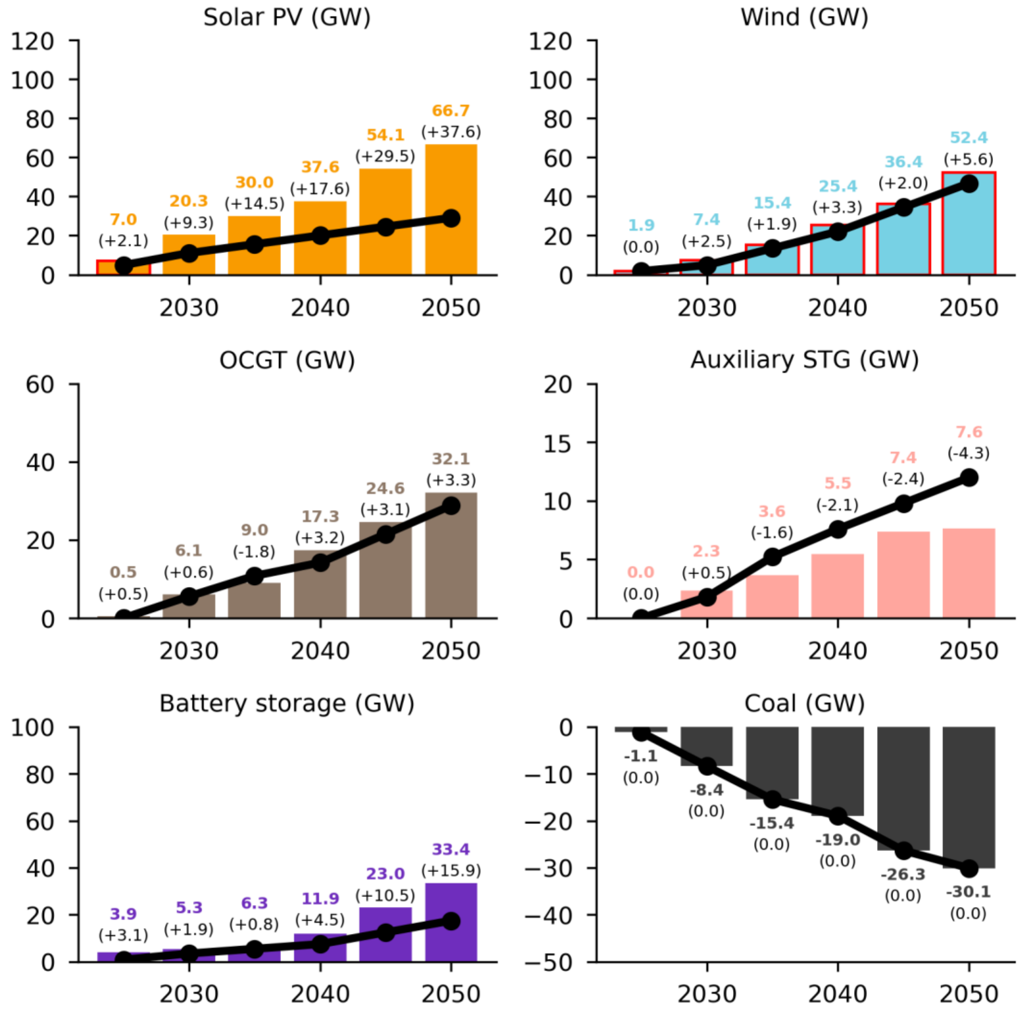


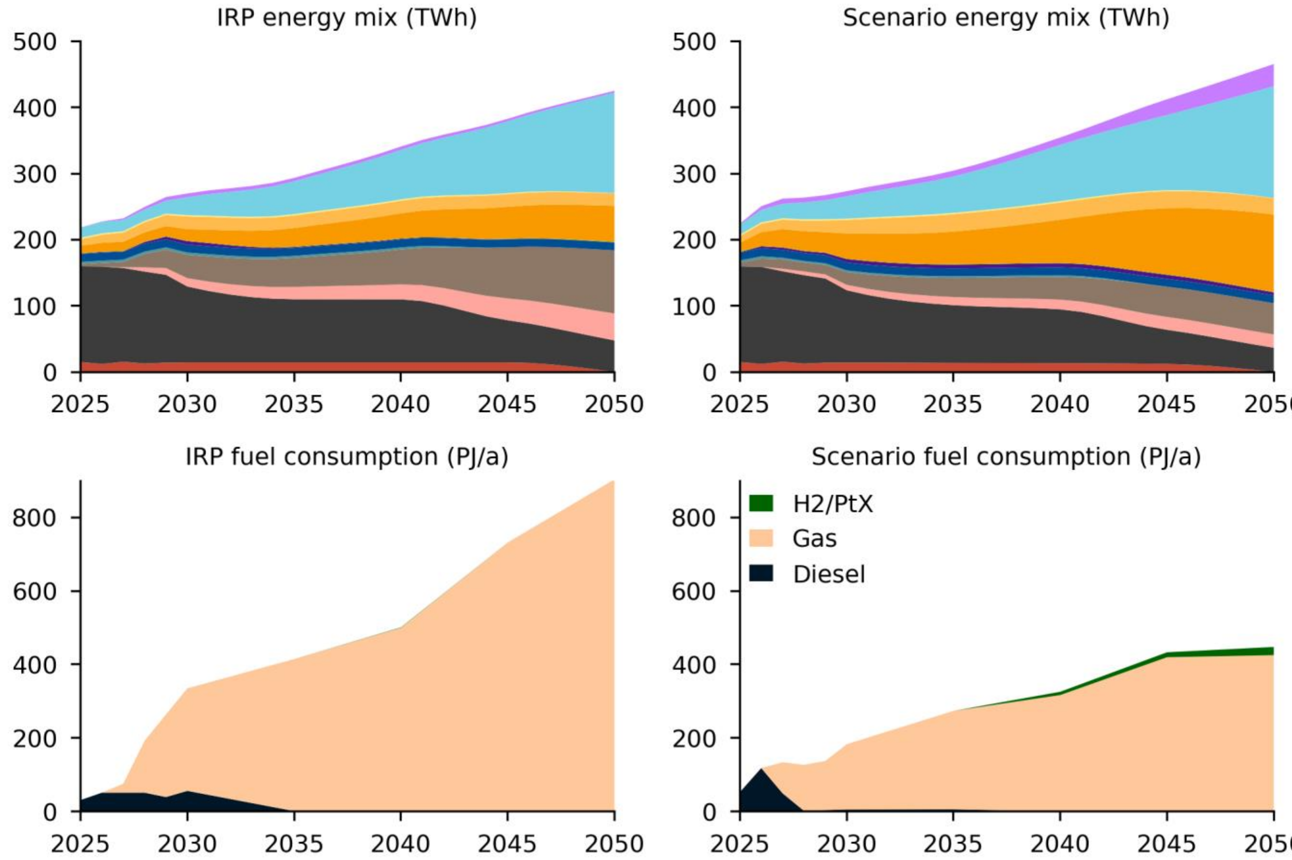


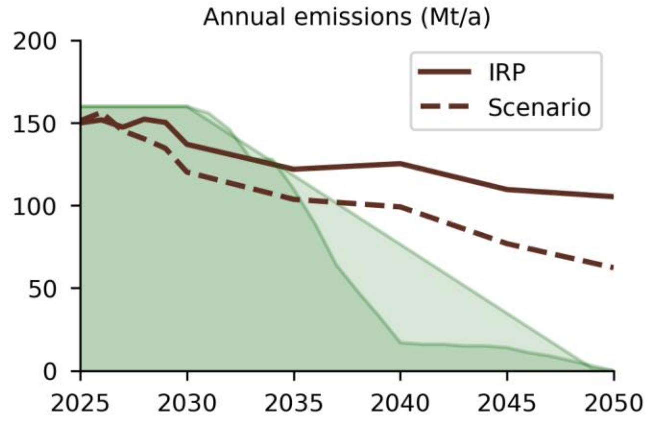
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-66.9% -49 TWh	-2.1%	-19.4% -631 Mt
(-4289 R'bn)	(-79 R'bn)	(-183 R'bn)

PESSIMISTIC RE BUILD

Cumulative new capacity from 2024



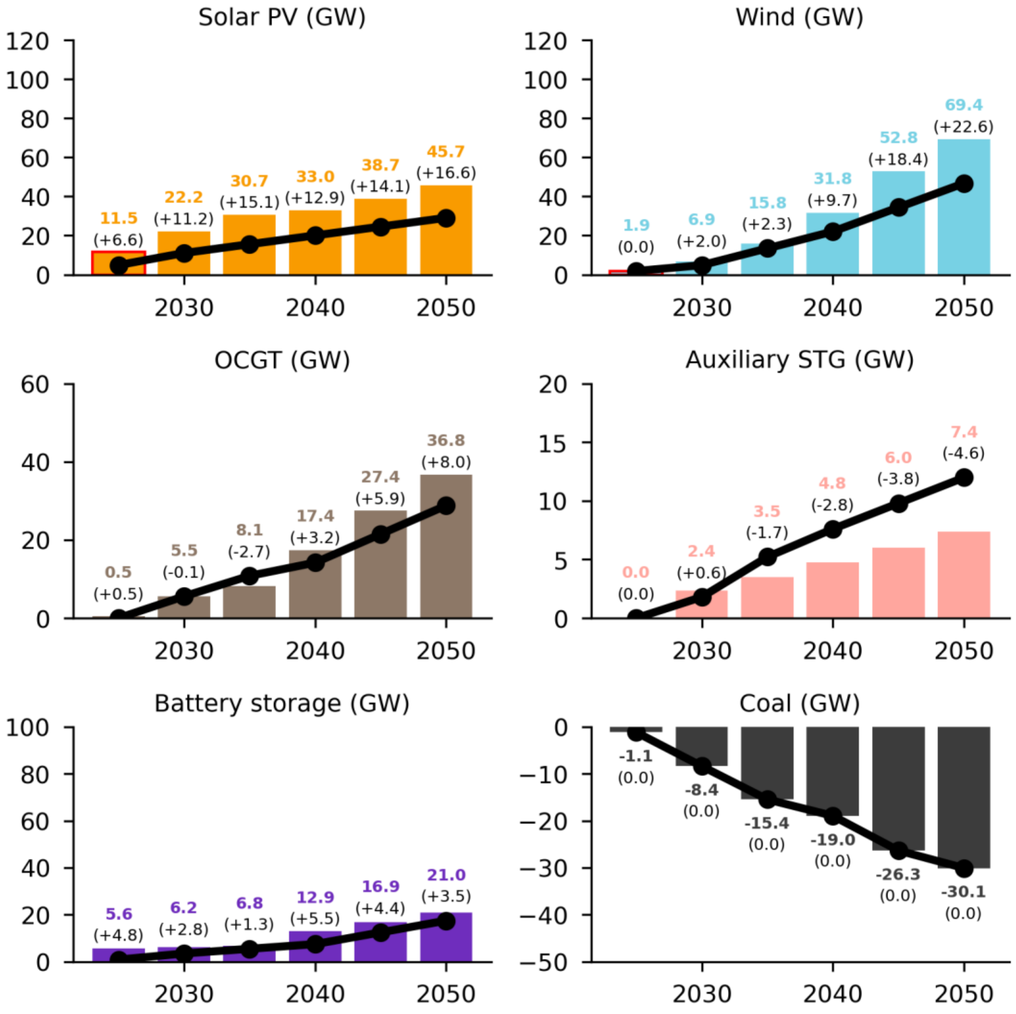


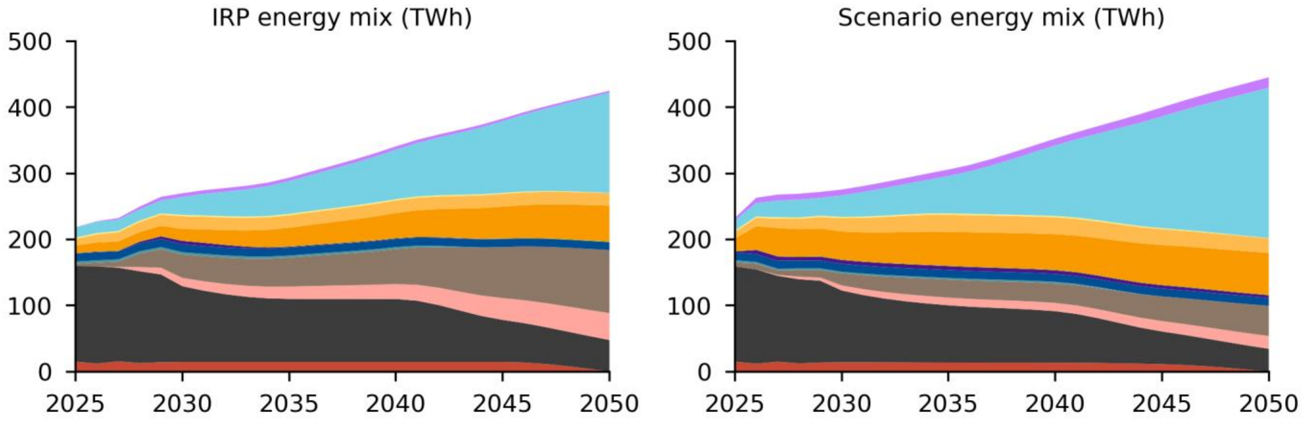


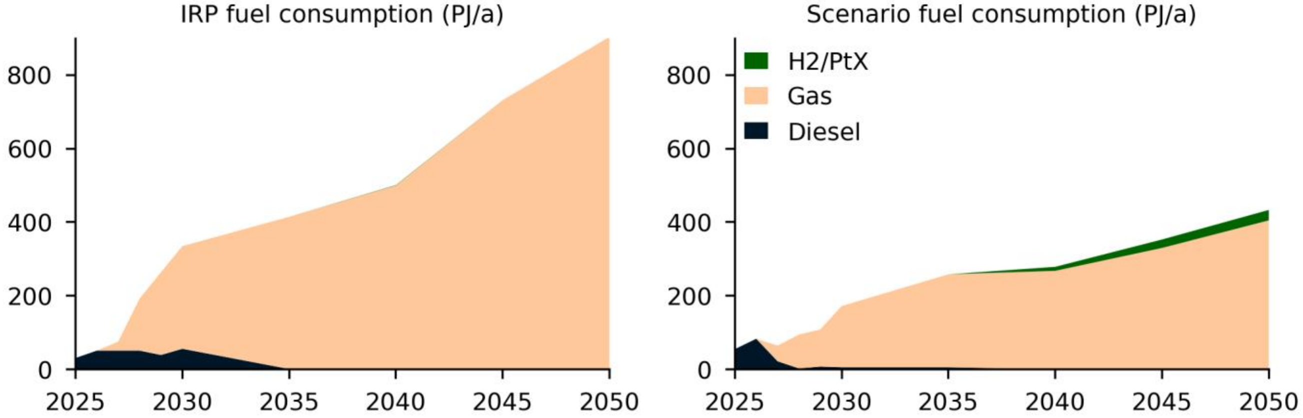
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-65.1% -48 TWh	-1.6%	-18.0% -586 Mt
(-4172 R'bn)	(-60 R'bn)	(-170 R'bn)

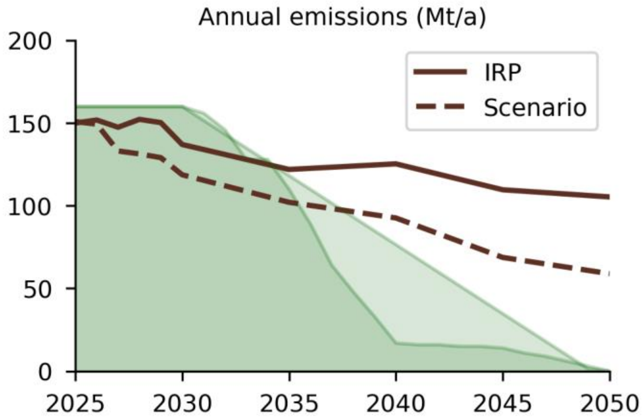
TARGETED SOLAR INTERVENTION

Cumulative new capacity from 2024









Load shedding	PV of costs 2025-2050	Cumulative Emissions
-79.1% -58 TWh	-2.4%	-22.1% -719 Mt
(-5153 R'bn)	(-93 R'bn)	(-208 R'bn)

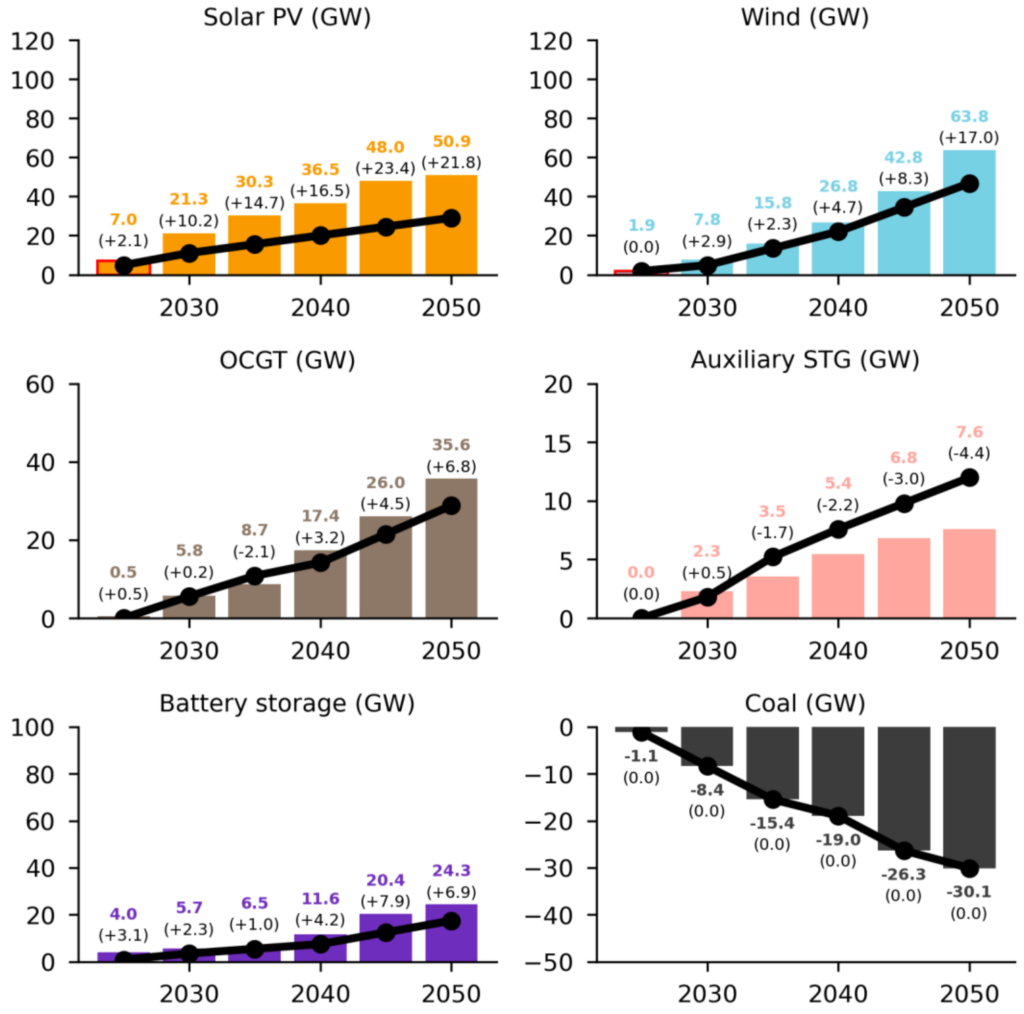
WHAT IF THE COAL EAF RECOVERS?

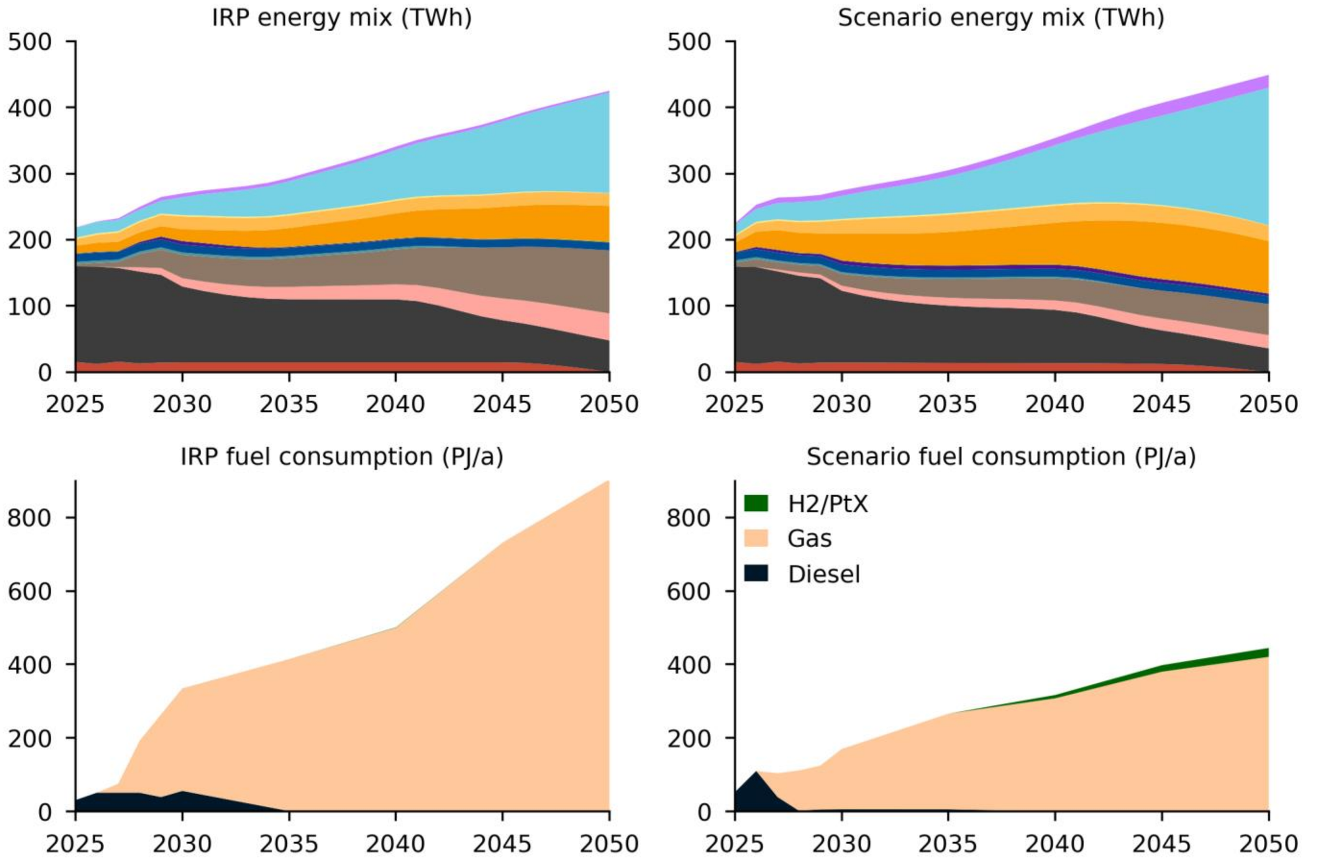
IF THE COAL FLEET RECOVERS, MUCH LESS GAS IS REQUIRED. BUT WHEN AND HOW MUCH WILL IT RECOVER?

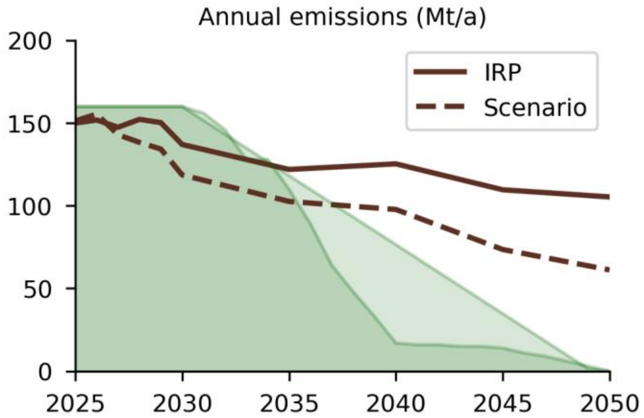
- Credible, significant coal performance recovery is unlikely in the short term as the energy shortfall prevents adequate maintenance
- The following slides show that coal EAF recovery has little or no impact on load shedding if new gas capacity is realised ontime (arrives too late)
- Reliable, forecastable EAF recovery would significantly reduce the size of near-term gas commitment required, significantly reducing system cost (11% reduction if coal EAF recovers to 70% by 2035) as coal is a cheaper fuel than gas.
  - This would be an exceptionally risky strategy, resulting in substantially higher emissions if recovery actually happened, and catastrophic load shedding if it did not
- The level, predictability and reliability of future coal EAF is a critical assumption in determining the scope and role of gas in the power system
  - Gas provides a measure of insurance against unpredictable coal fleet performance

BASE CASE RECAP (RE BUILD, RE COSTS, EAF)

Cumulative new capacity from 2024



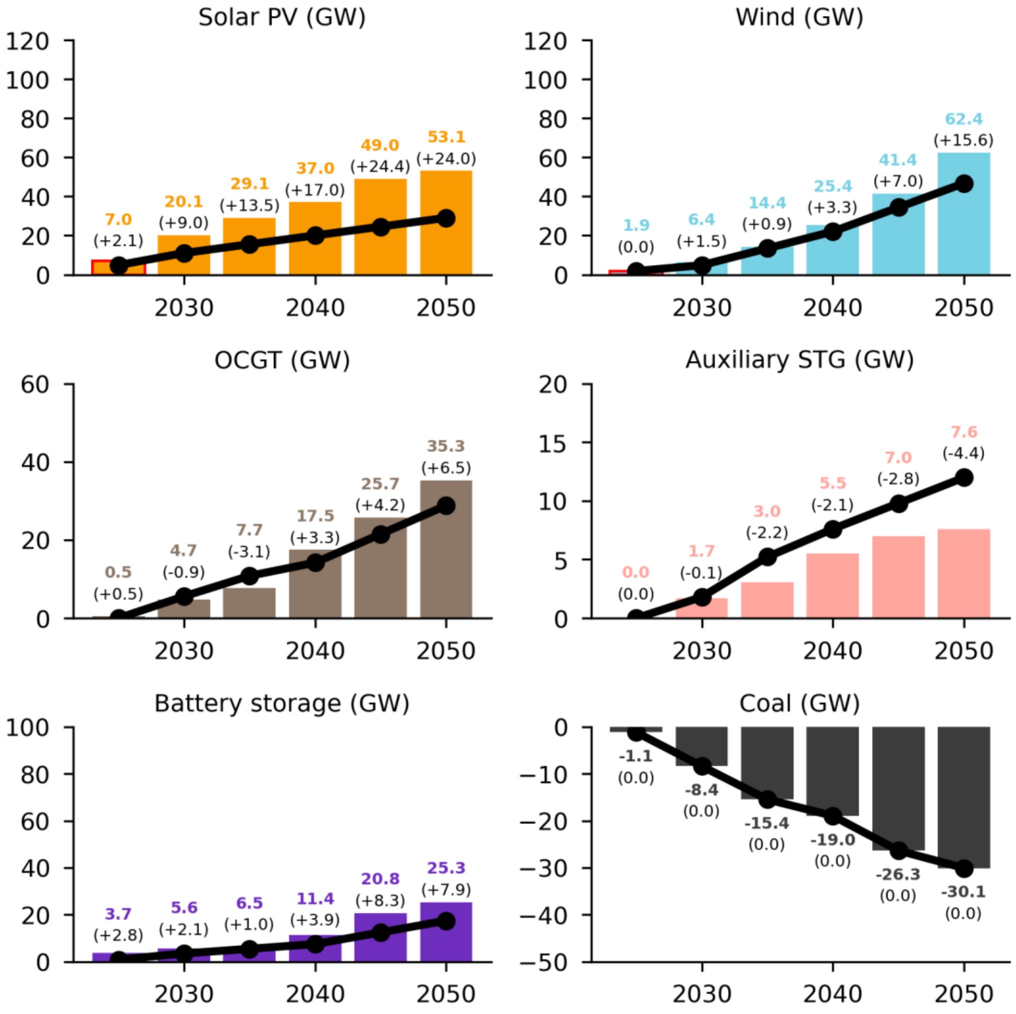


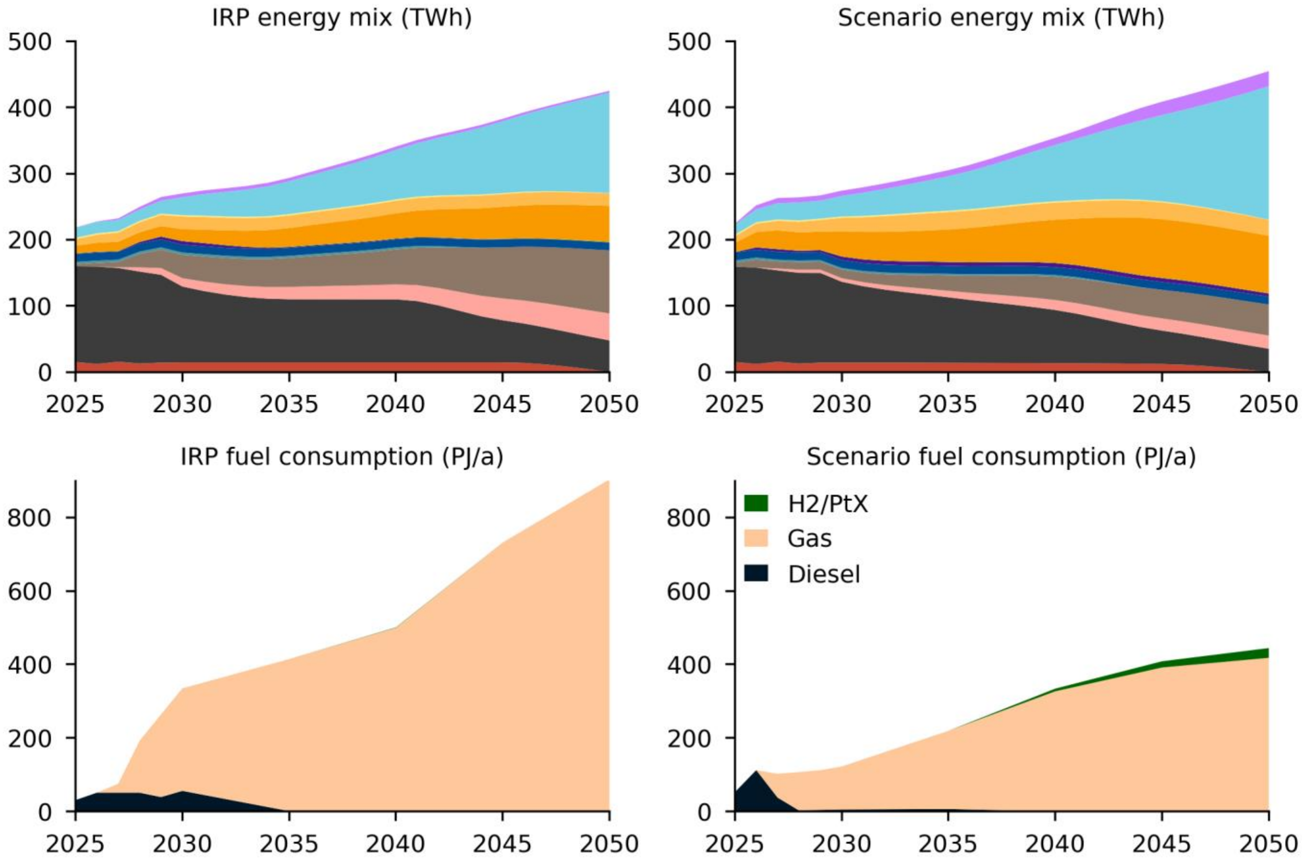


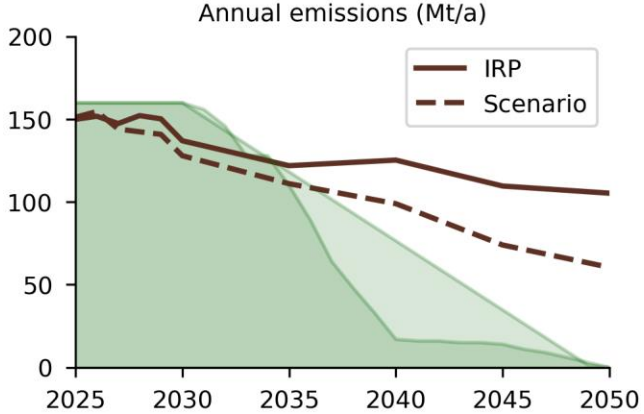
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-66.9% -49 TWh	-2.1%	-19.4% -631 Mt
(-4289 R'bn)	(-79 R'bn)	(-183 R'bn)

COAL EAF RECOVERS TO 50% BY 2035

Cumulative new capacity from 2024



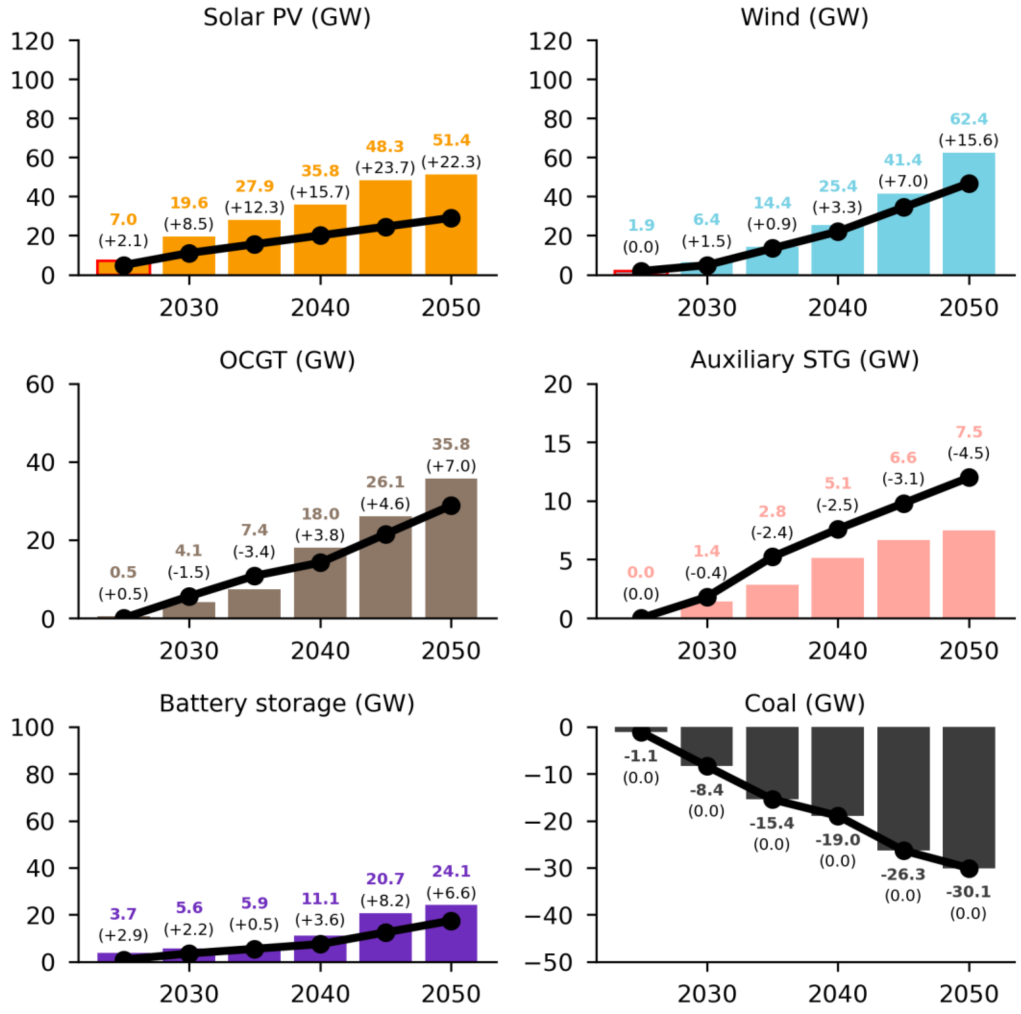


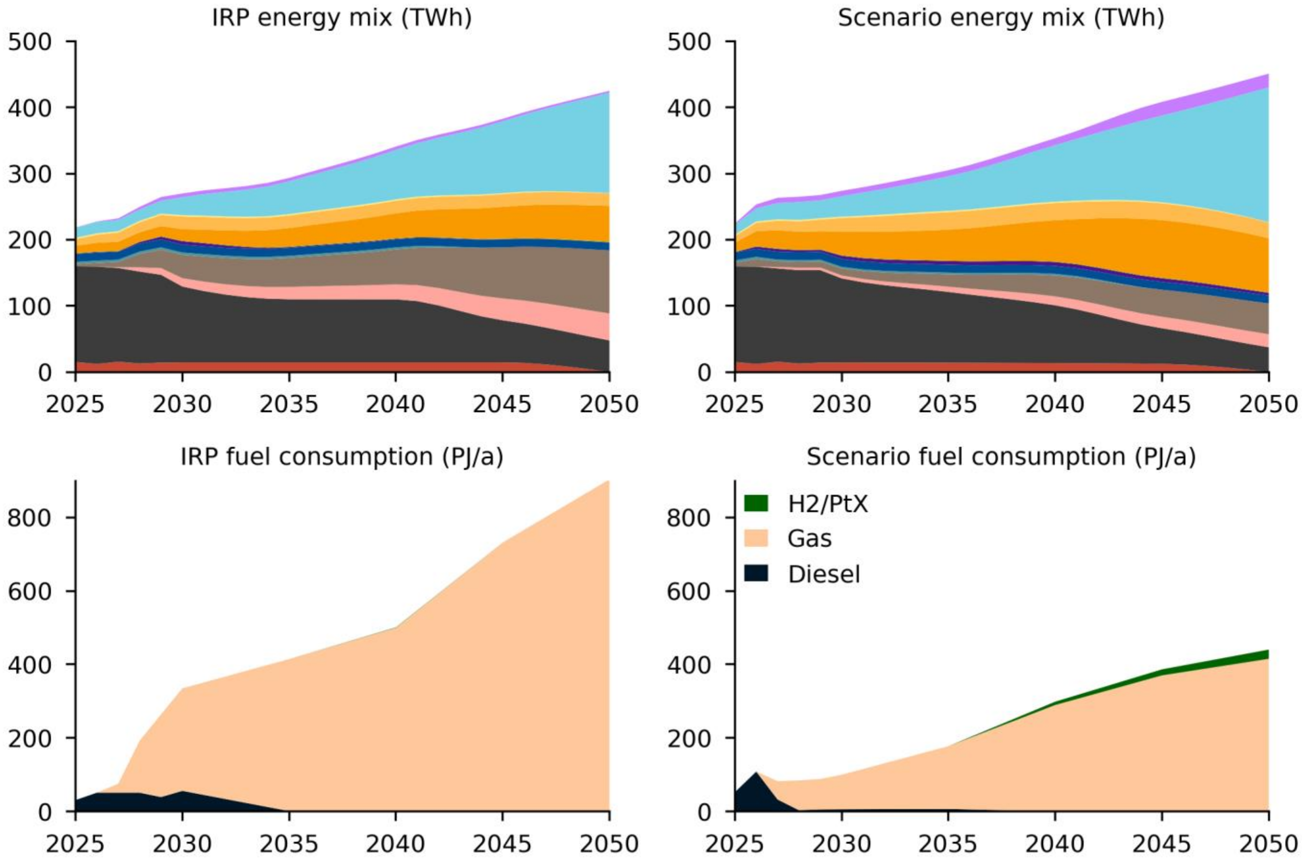


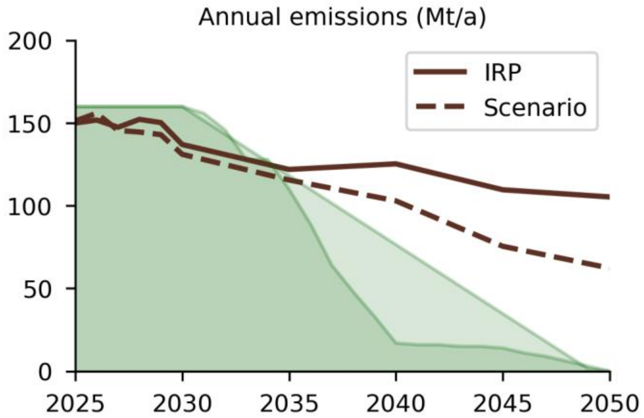
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-65.8% -48 TWh	-4.2%	-16.7% -542 Mt
(-4221 R'bn)	(-160 R'bn)	(-155 R'bn)

COAL EAF RECOVERS TO 55% BY 2035

Cumulative new capacity from 2024



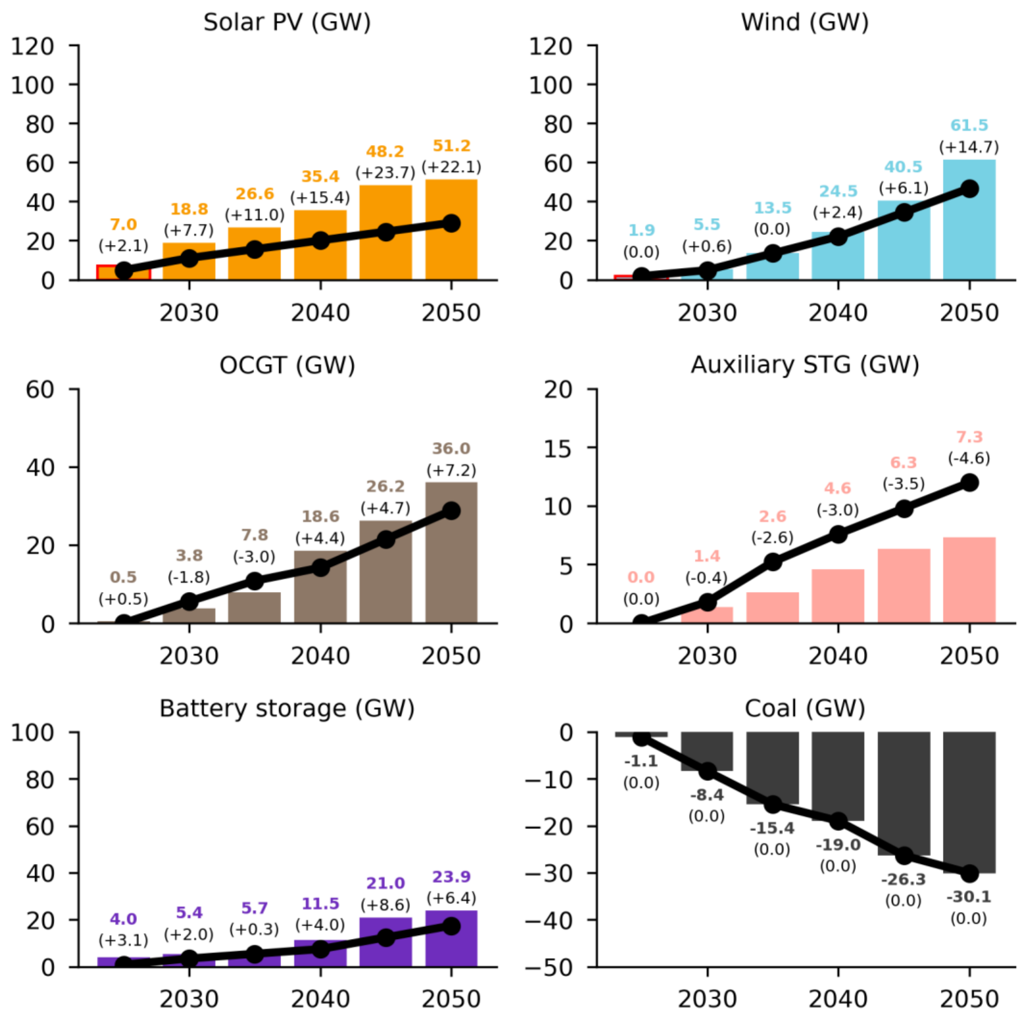


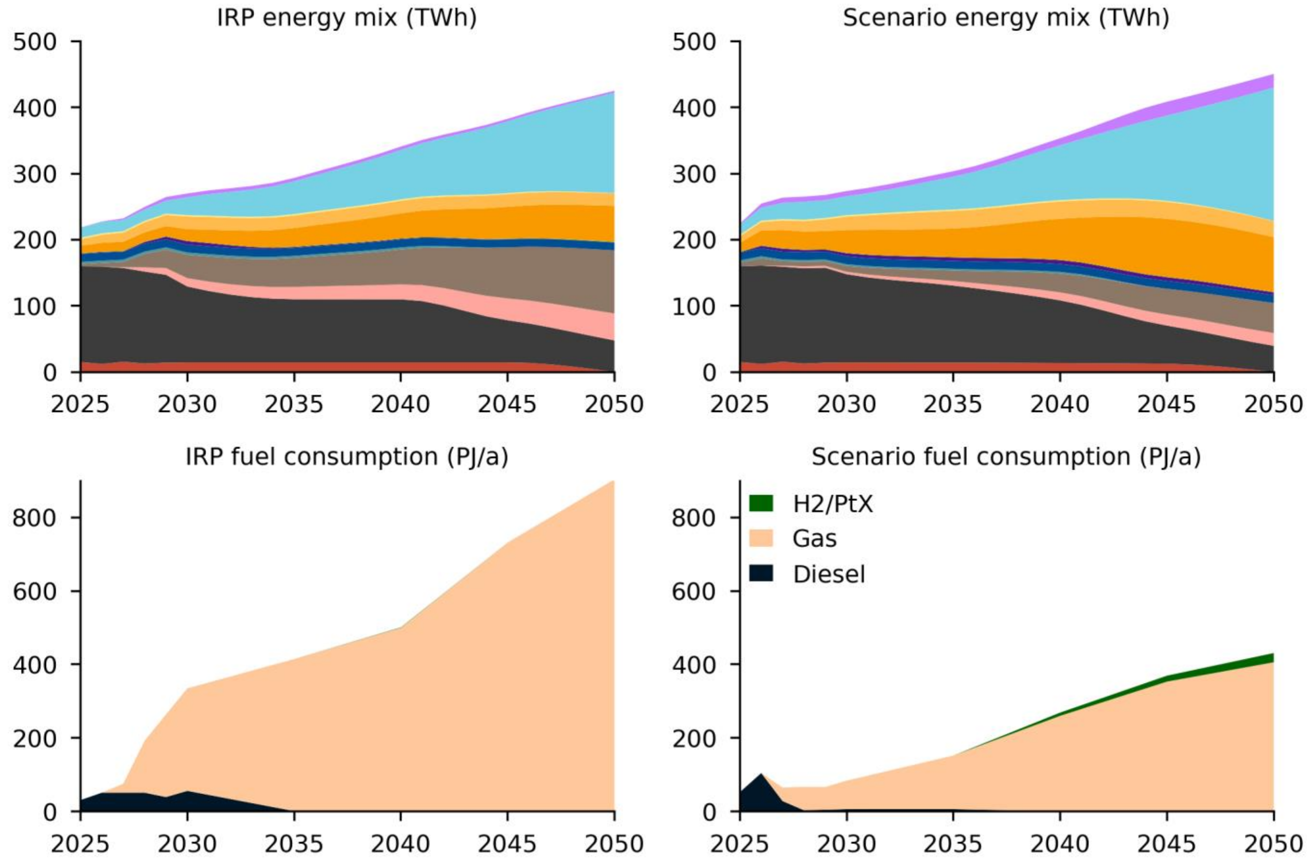


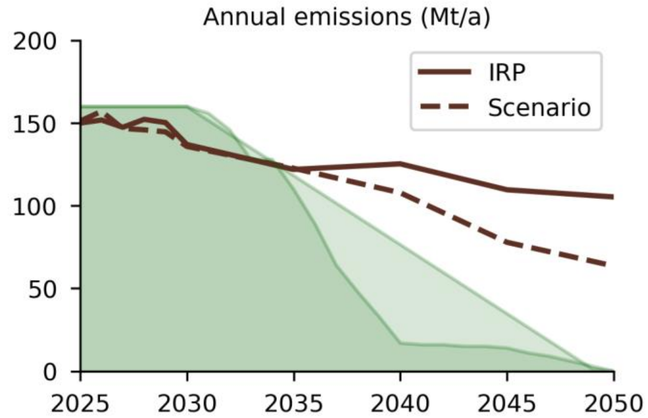
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-67.4% -49 TWh	-6.0%	-14.5% -471 Mt
(-4329 R'bn)	(-230 R'bn)	(-134 R'bn)

COAL EAF RECOVERS TO 60% BY 2035

Cumulative new capacity from 2024



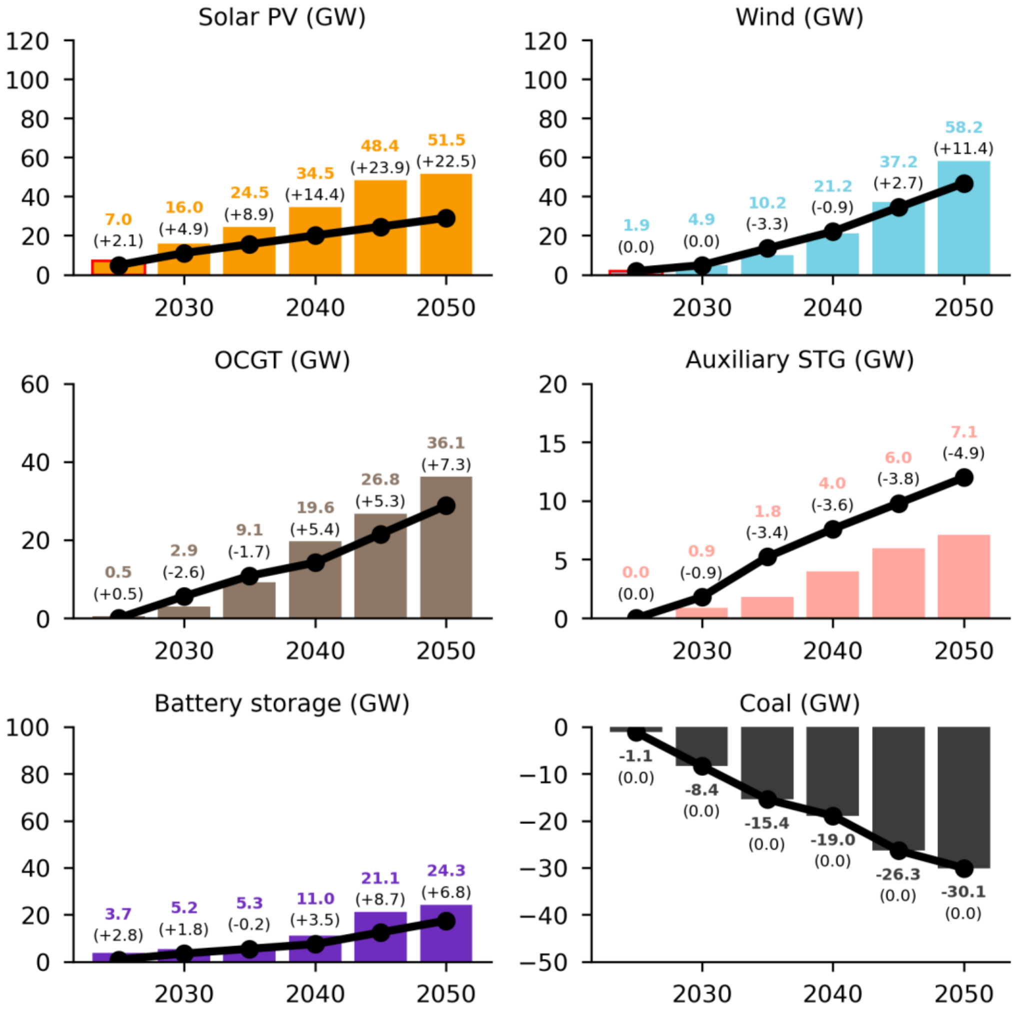


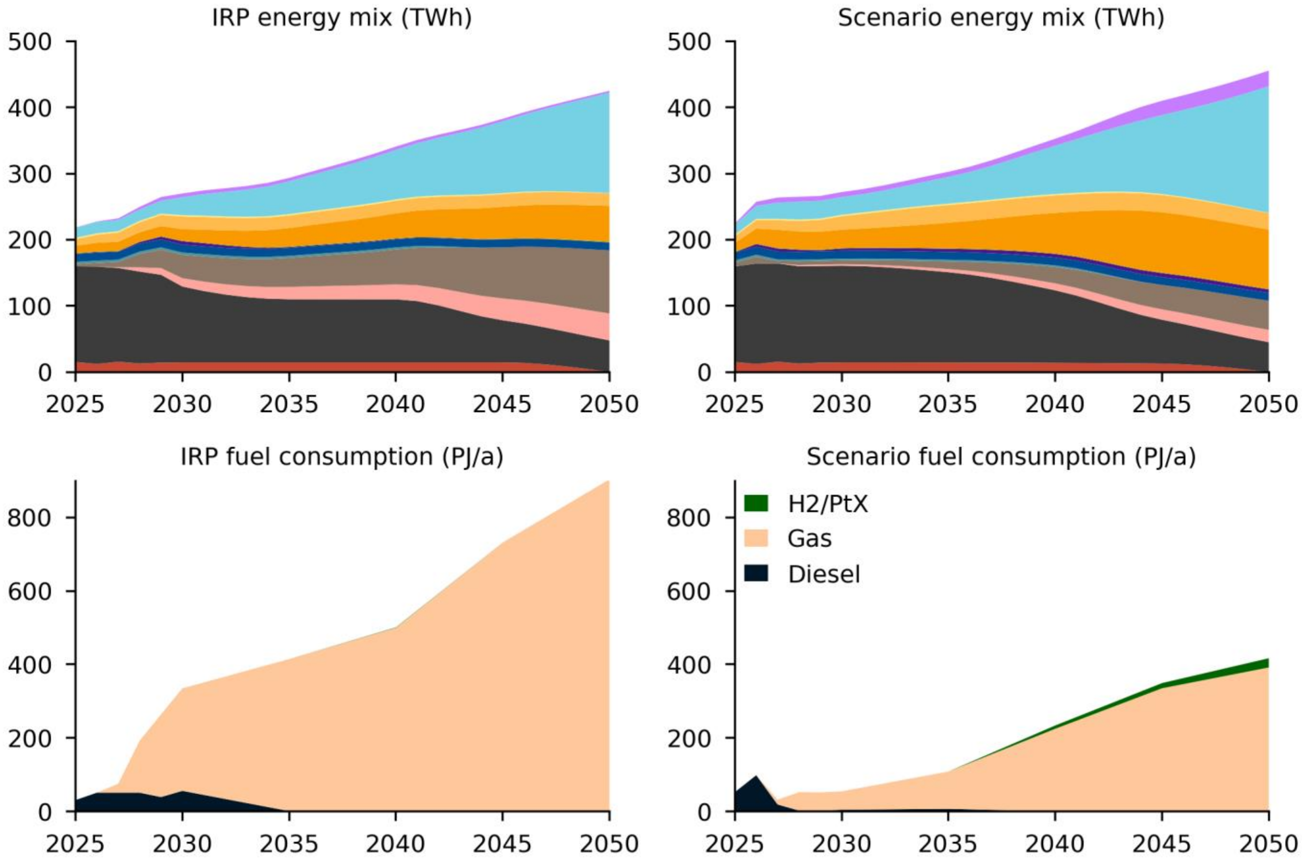


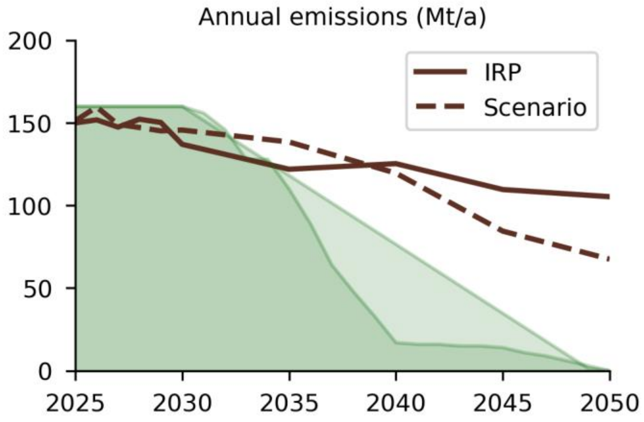
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-68.5% -50 TWh	-7.9%	-11.5% -373 Mt
(-4400 R'bn)	(-300 R'bn)	(-104 R'bn)

COAL EAF RECOVERS TO 70% BY 2035

Cumulative new capacity from 2024







Load shedding	PV of costs 2025-2050	Cumulative Emissions
-71.4% -52 TWh	-11.2%	-4.4% -144 Mt
(-4596 R'bn)	(-426 R'bn)	(-36 R'bn)

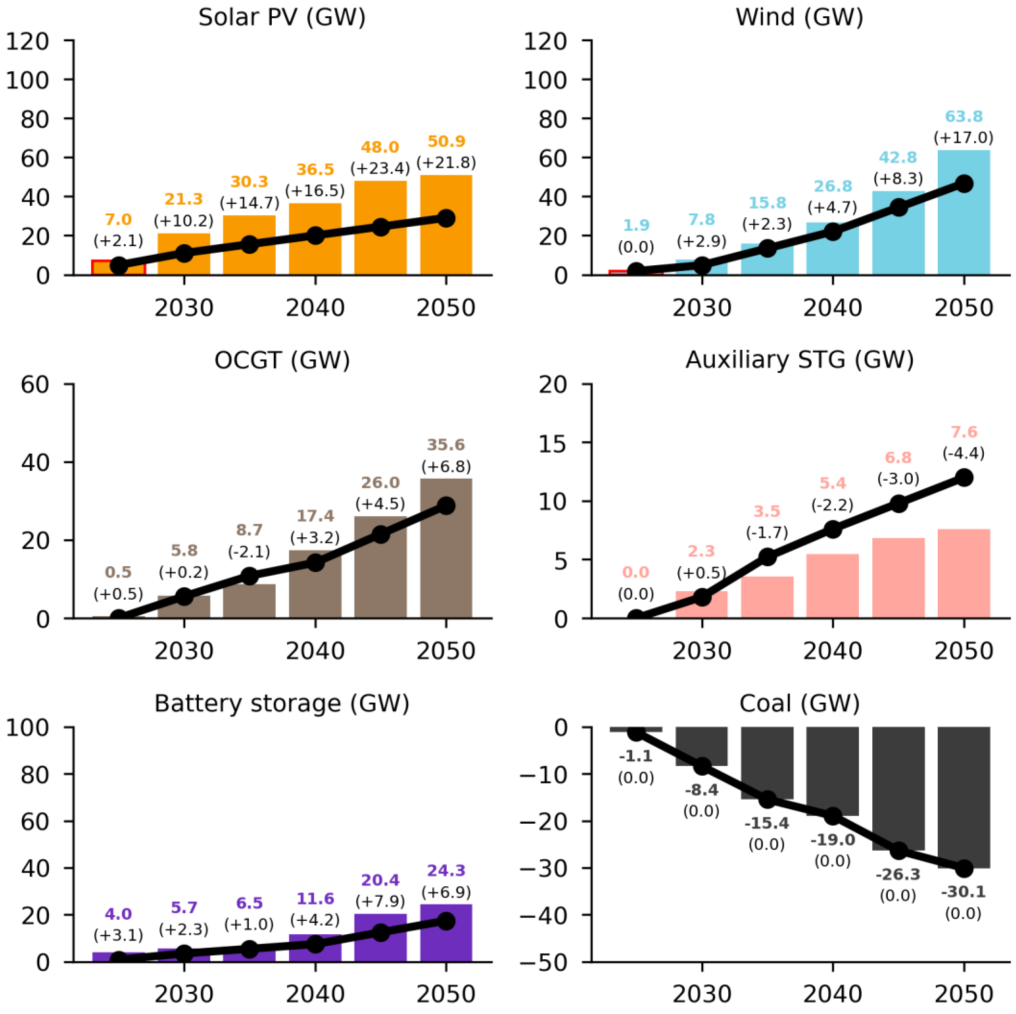
WIND, SOLAR, BATTERY COST DECLINES ARE A KEY UNKNOWN

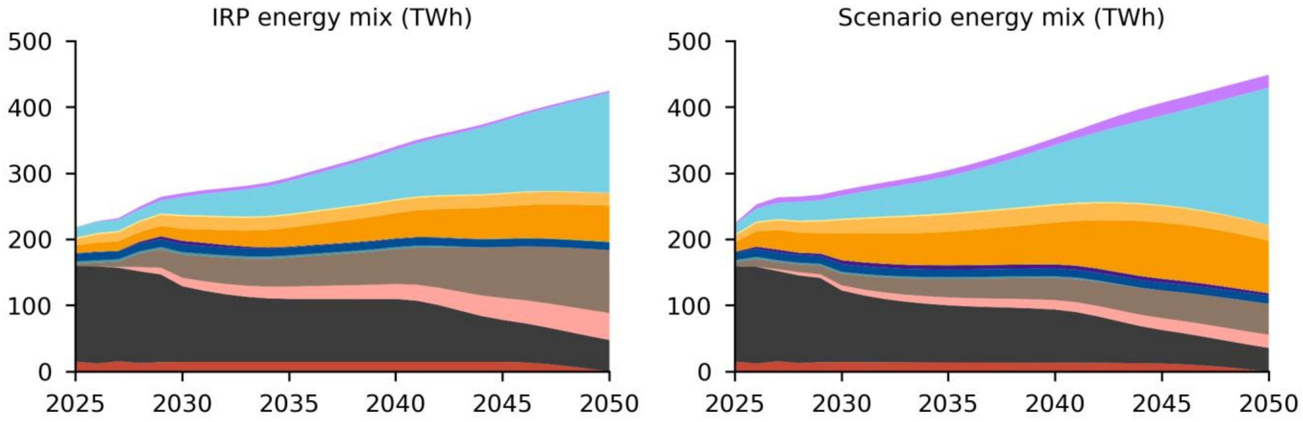
BUT, HIGHER RE COSTS HAVE NO NEAR-TERM IMPACT ON SOLAR & BATTERY BUILD, SOME REDUCTION IN WIND

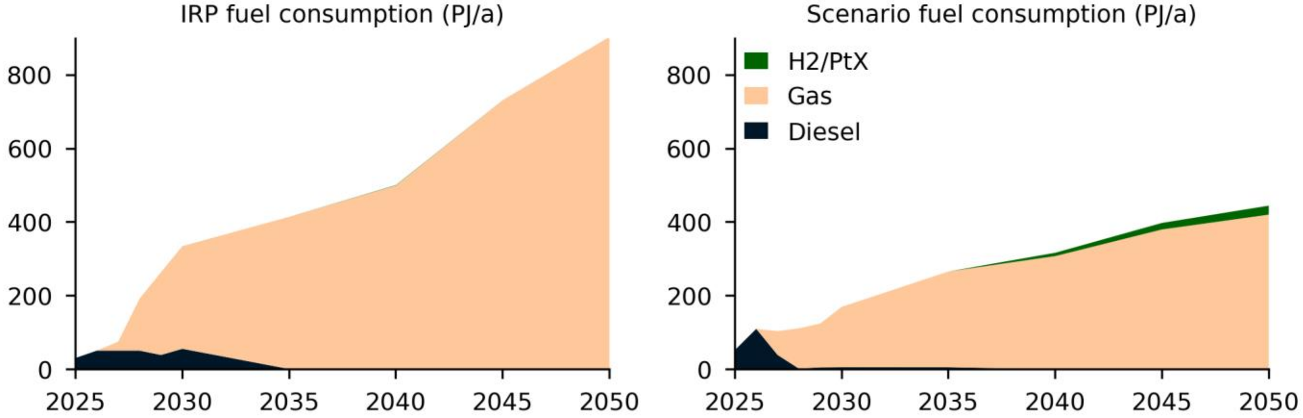
- The next slides contrast impact of our base case cost assumptions, with a higher cost stress case for Wind, Solar and Batteries, as well as a more likely cost learning path for these technologies.
- Stress costs for Wind and Solar are approximately 50% higher than those achieved in BW6 (see technical appendix)
- Under the **stress costs**
  - There is little change to solar and battery deployment particularly to 2030 (this need is driven by load shedding). Optimal capacity is substantially higher than the IRP.
  - Wind expansion is in line with IRP to 2030 when, if higher costs persist it would be economic to install less wind than the IRP
  - Like the IRP 2023 plan, this power system is highly dependent on the pace and scale of gas rollout
  - Emissions reduction relative to the IRP is significantly reduced under this scenario as gas is more competitive with wind and its use increases
- Under **likely cost learning**
  - Little change to solar and battery deployment prior to 2030. Later years see substantial increase in solar and battery capacity
  - Wind capacity expansion is bounded only by the base case build constraints and highlights the need to address grid and logistical barriers to deployment under likely future wind cost scenarios.
  - Much less gas is utilised, highlighting the risk of stranded gas assets and contractual commitments under likely renewable cost declines i.e. if gas decisions now are based on unrealistically high future renewables costs as is the case in the IRP 2023
  - Emissions are 26% lower than the IRP under this scenario

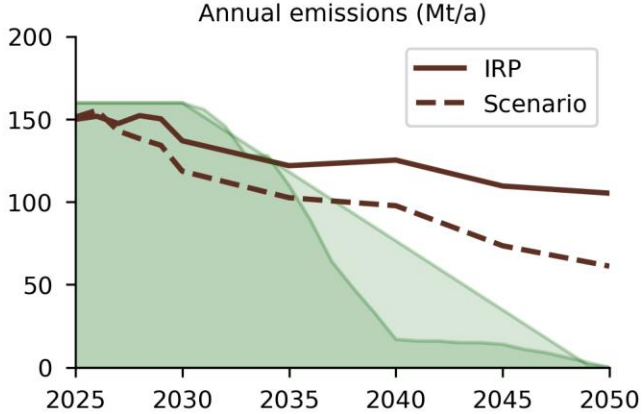
BASE CASE RECAP (RE BUILD, RE COSTS)

Cumulative new capacity from 2024





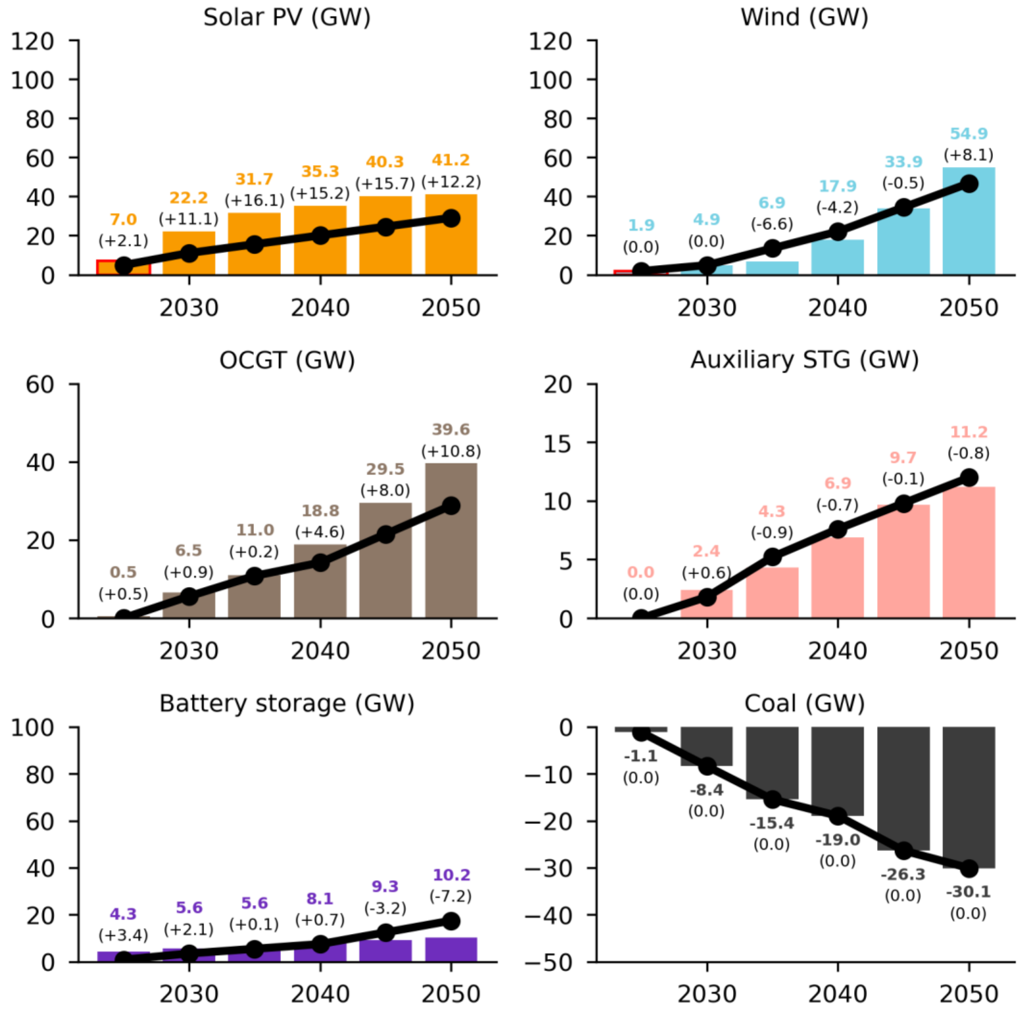


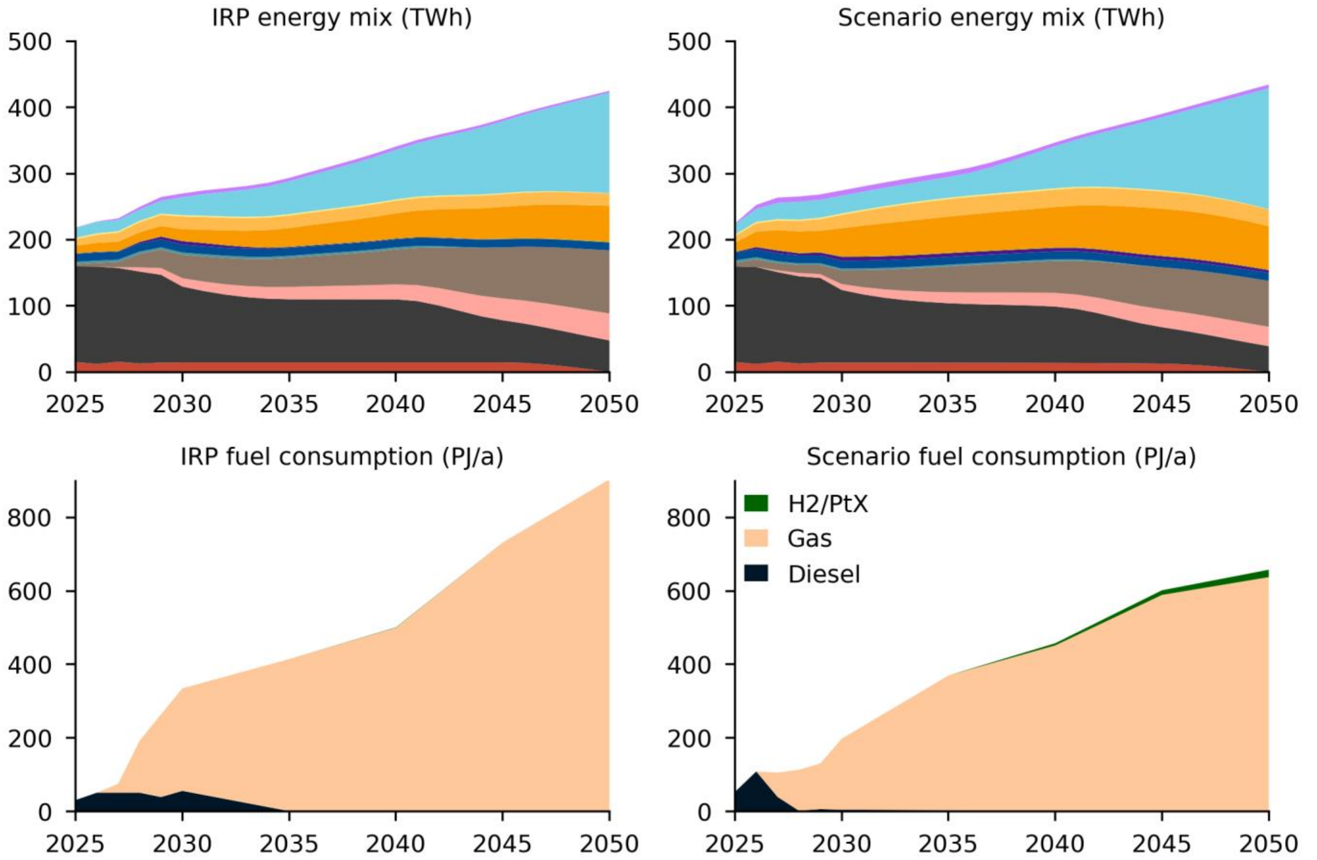


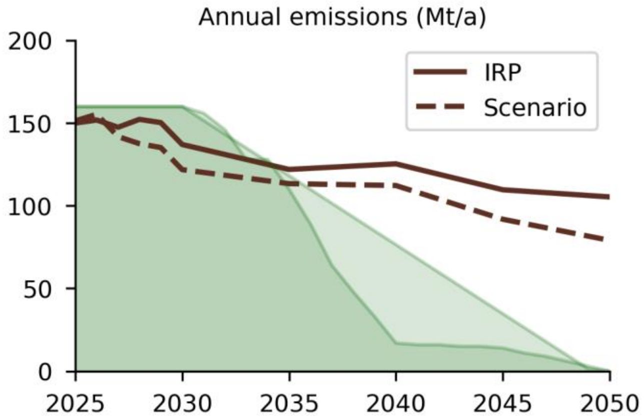
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-66.9% -49 TWh	-2.1%	-19.4% -631 Mt
(-4289 R'bn)	(-79 R'bn)	(-183 R'bn)

BASE CASE RE BUILD, STRESS RE COSTS

Cumulative new capacity from 2024



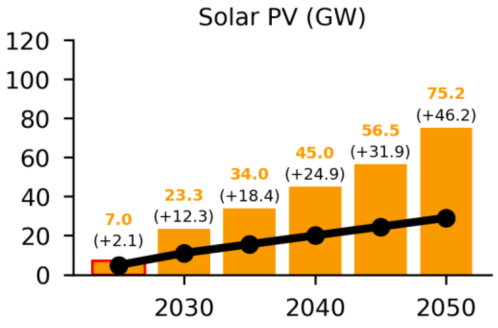


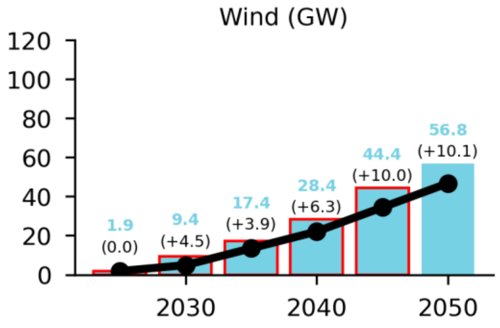


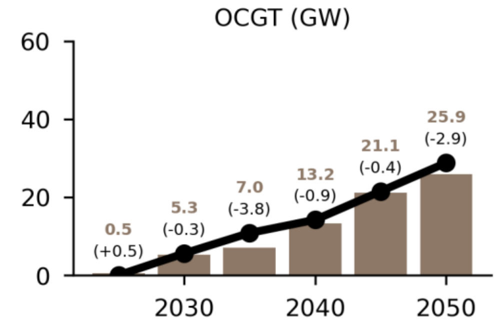
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-66.6% -49 TWh	-1.1%	-10.6% -345 Mt
(-4267 R'bn)	(-47 R'bn)	(-100 R'bn)

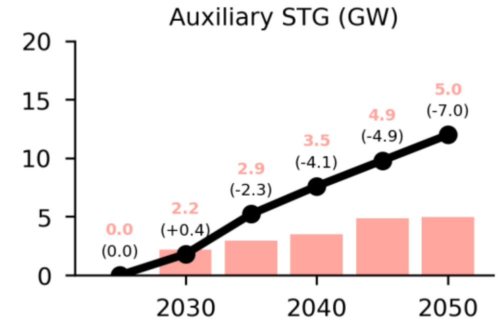
BASE CASE RE BUILD, LIKELY RE LEARNING

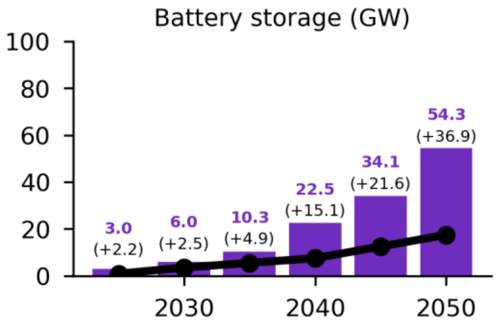
Cumulative new capacity from 2024

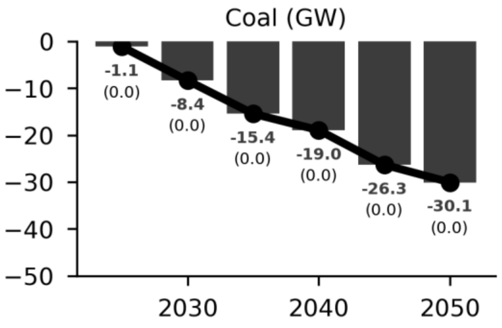


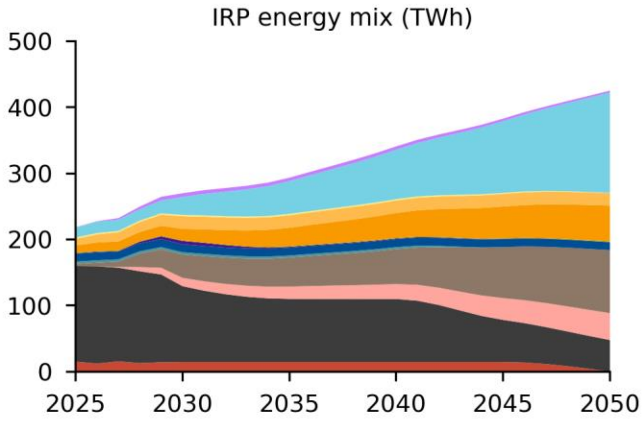


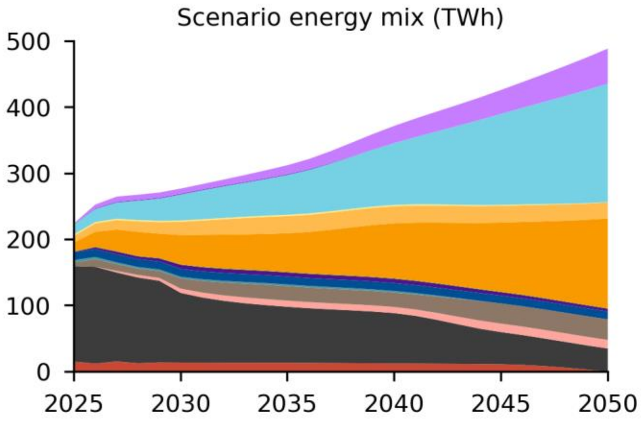


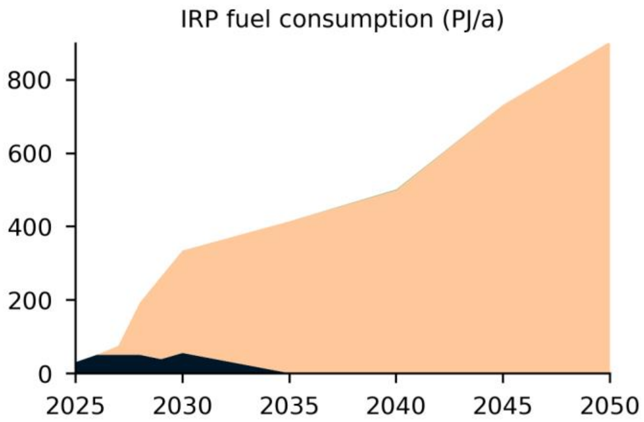


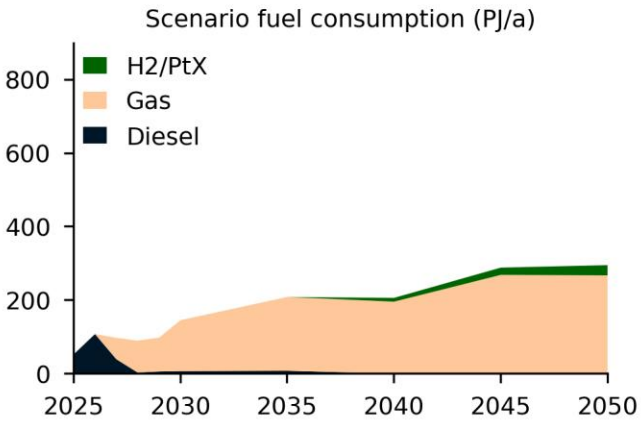


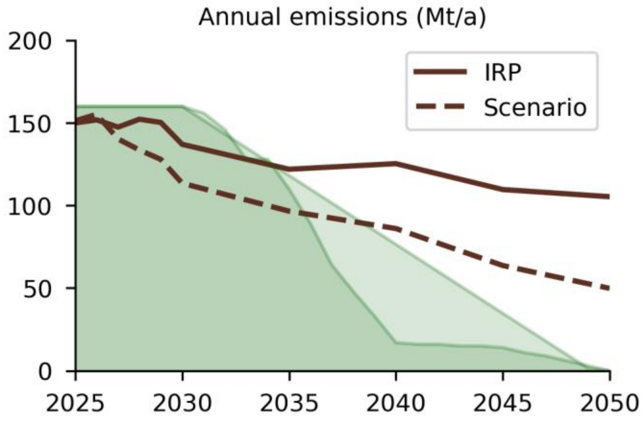












Load shedding	PV of costs 2025-2050	Cumulative Emissions
-66.4% -48 TWh	-4.3%	-25.6% -832 Mt
(-4252 R'bn)	(-158 R'bn)	(-241 R'bn)

PATHWAYS TO A NET ZERO ECONOMY BY 2050

WHAT ARE THE NEAR-TERM IMPLICATIONS AND WHAT WILL IT COST TO GET TO A ZERO-EMISSION POWER SYSTEM?

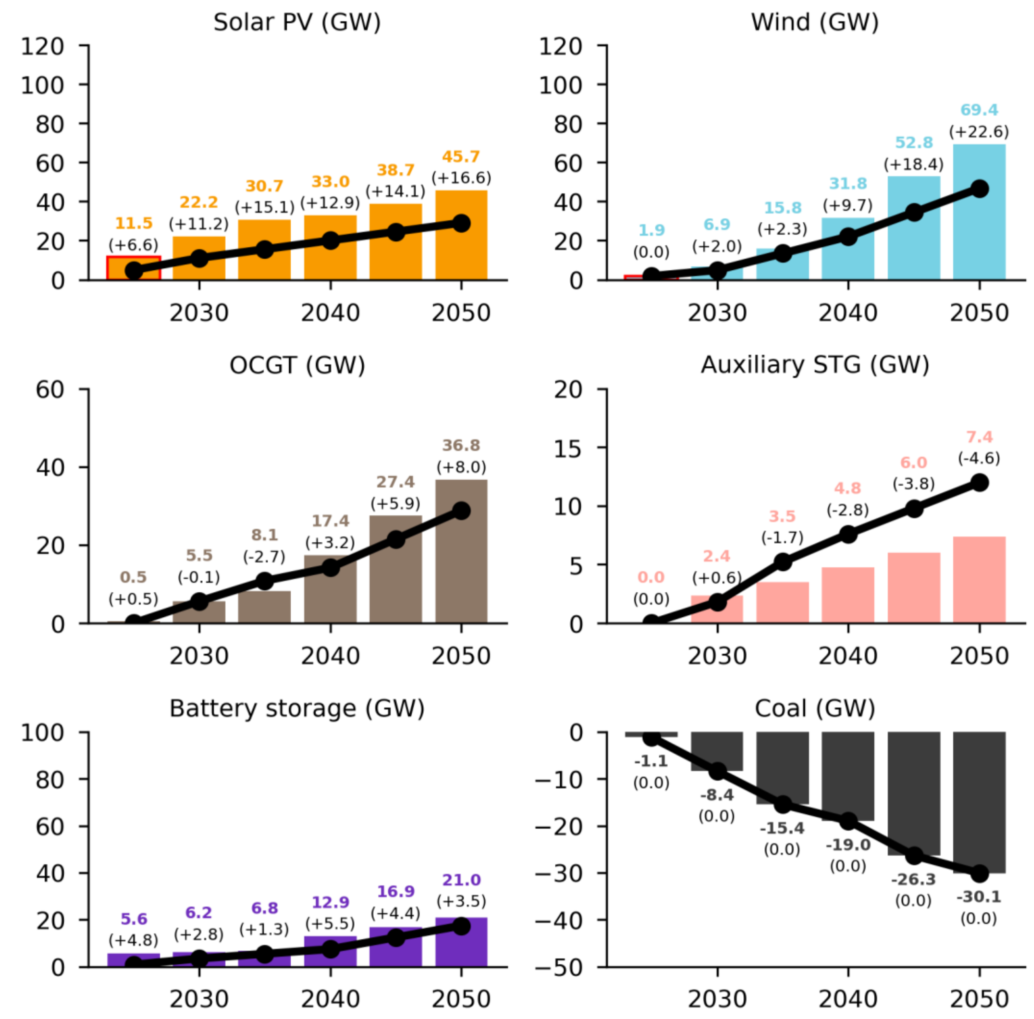
- The final suite of scenarios compares the targeted solar intervention with further measures to eliminate power sector carbon emissions by 2050.
  - "**Targeted solar, price on carbon**" considers an accelerated coal decommissioning schedule with full closure by 2050. The National Treasury carbon tax is internalised into the power system design by minimising this cost alongside others. This results in the elimination of any system cost saving vs the IRP 2023, but reduces emissions to 2050 by 40% or 1.3Gt. This pathway does not get to zero emissions, with OCGT gas-fired capacity burning 180PJ/a and supporting almost 4GW of STG in 2050. The Wind build constraint is binding in all scenarios in this suite – i.e it would be more economic to install more wind, and burn less gas.
  - "**Targeted solar, NZ2050**" models an allowable emission envelope that decreases linearly to zero in 2050. Imposing the zero emission constraint increases system cost by 5% relative to the IRP – the "last mile" premium. This premium could be reduced by removing constraints on Wind build which are binding for all periods to 2050. Auxiliary STG capacity is sub-economic, highlighting the stranding risk of gas infrastructure under Net Zero pathways.
  - "**Targeted solar, price on carbon (coal off by 2040)**" considers coal closure by 2040 with internalised carbon price but no emissions constraint. 1.6GT (49%) of emissions are reduced at a cost premium of 3% relative to the IRP. Coal makes space for gas emissions which are slightly higher in 2050 than if coal remains to this date.
  - "**Targeted solar, NZ 2050, 9GT budget**" combines coal closure by 2040 with Zero emissions by 2050. This power system is the same as the NZ2050 scenario by 2050, but replacing coal with solar and batteries ten years earlier creates a higher cost premium of 9% compared to the IRP.

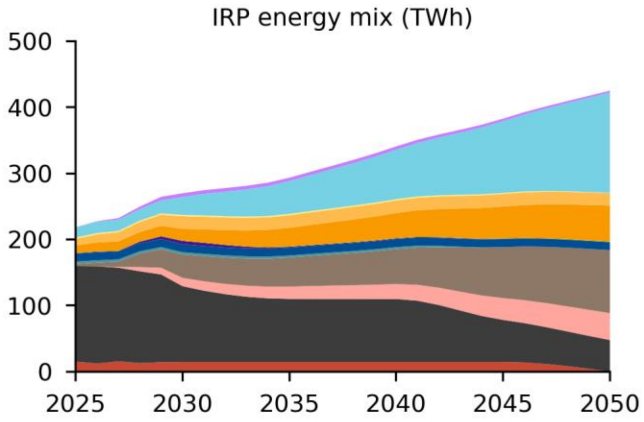
All the Net Zero scenarios require a large and exponentially growing storage roll-out. This will be a critical challenge and important localisation / industrialisation opportunity for South Africa. In the modelled Net Zero scenarios where coal is closed by 2040 the model builds between approximately 30 – 37 GW of storage in the preceding 5-year period (we did not apply battery build constraints). In practice this build requirement will take longer, say between 10 – 15 years.

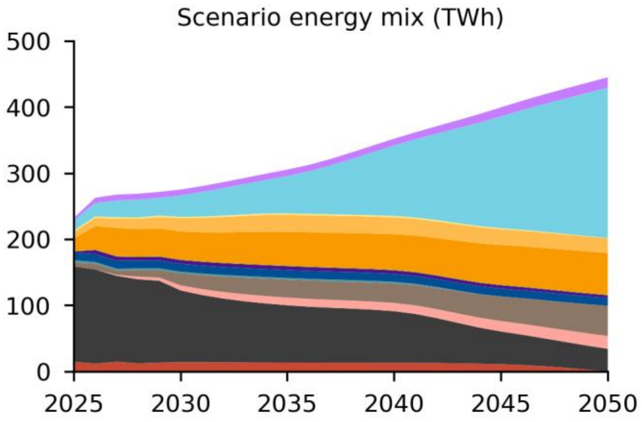
The cost of the additional emissions generated by the IRP 2023 plan, valued at a carbon price aligned to the National Treasury carbon tax, far outweighs any system cost premium of the decarbonisation scenarios in this suite . Furthermore, the real cost of emissions is likely to be far higher than modelled here.

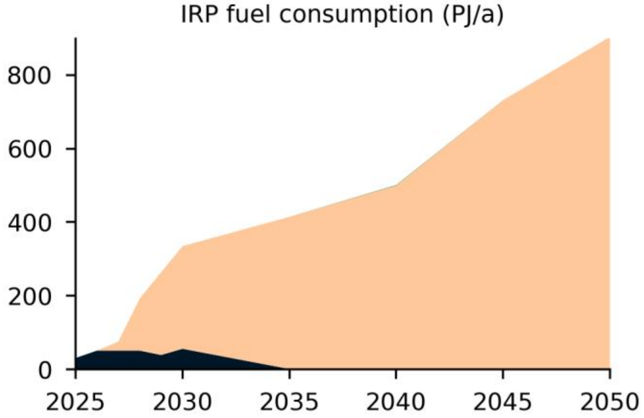
TARGETED SOLAR INTERVENTION (RECAP)

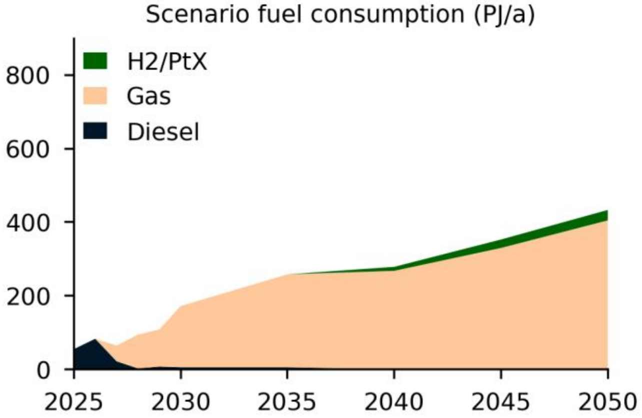
Cumulative new capacity from 2024

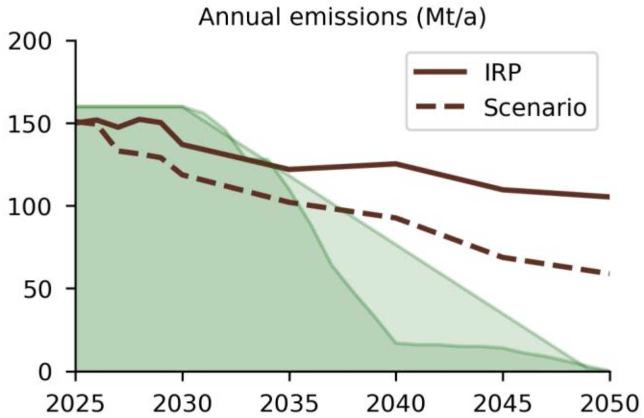








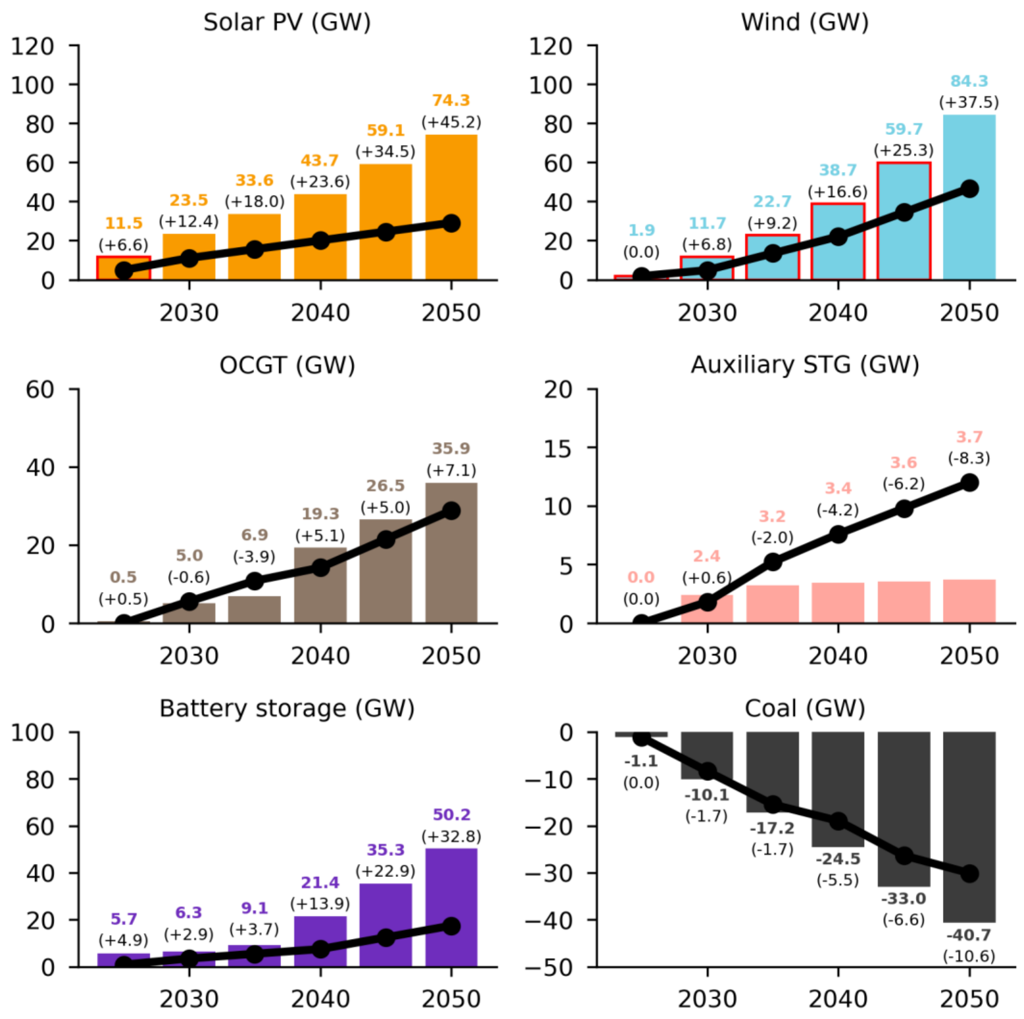


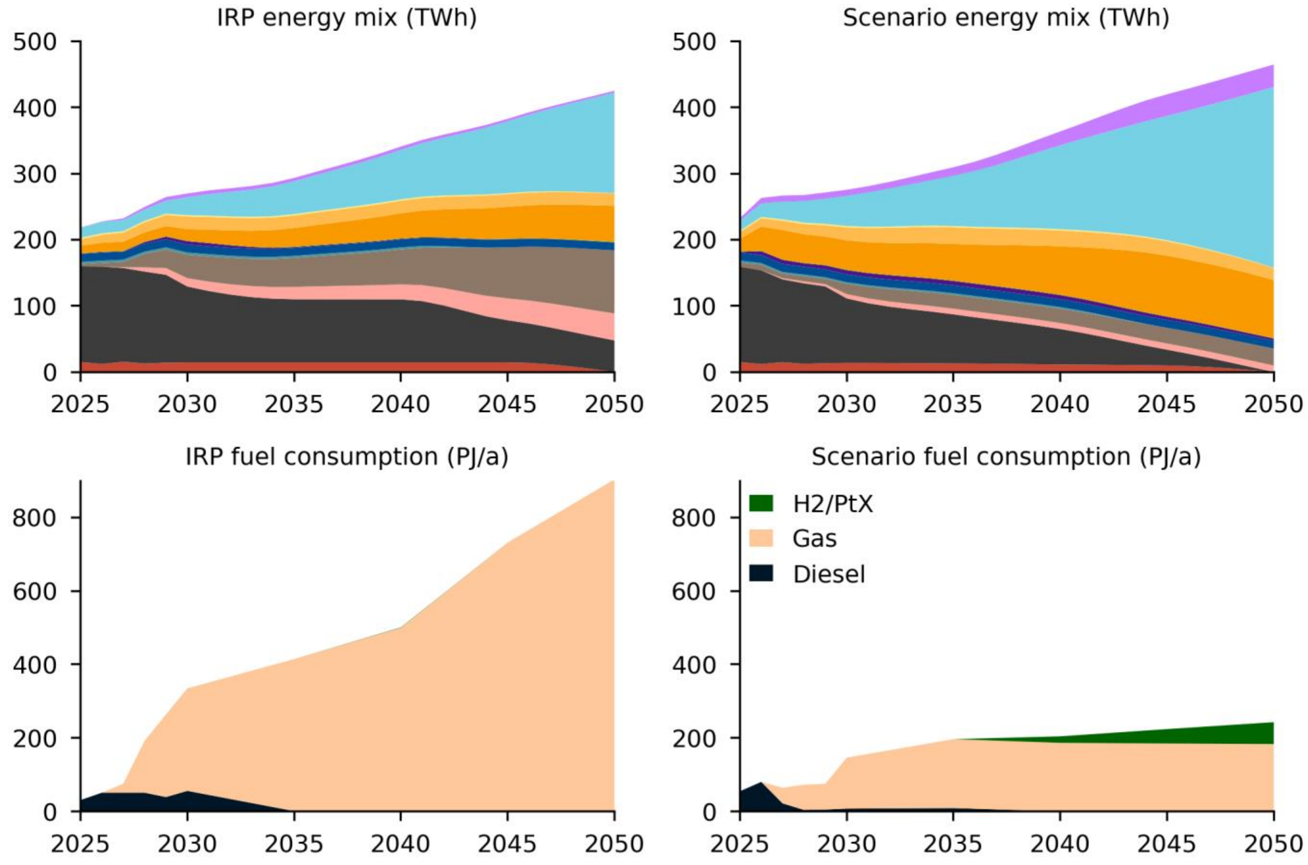


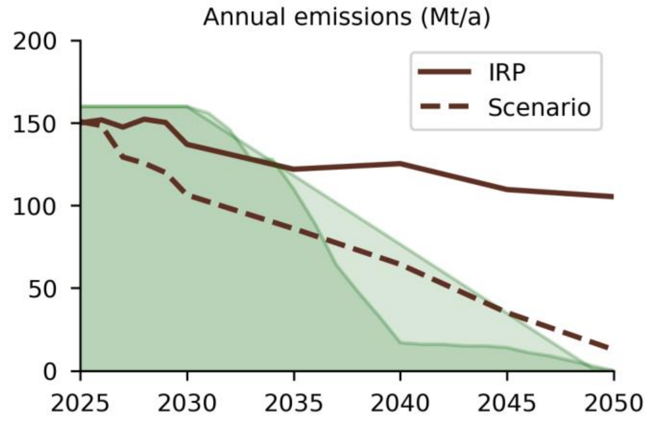
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-79.1% -58 TWh	-2.4%	-22.1% -719 Mt
(-5153 R'bn)	(-93 R'bn)	(-208 R'bn)

TARGETED SOLAR, PRICE ON CARBON

Cumulative new capacity from 2024



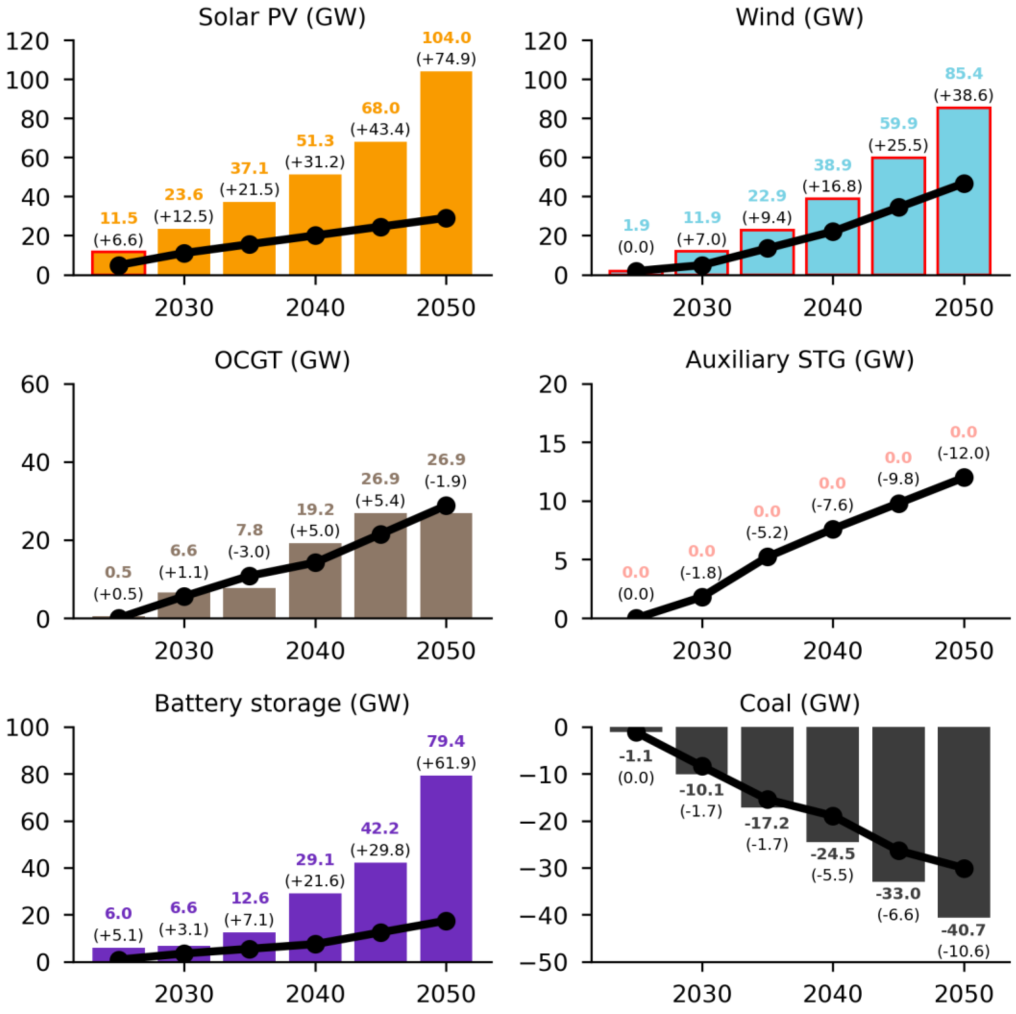


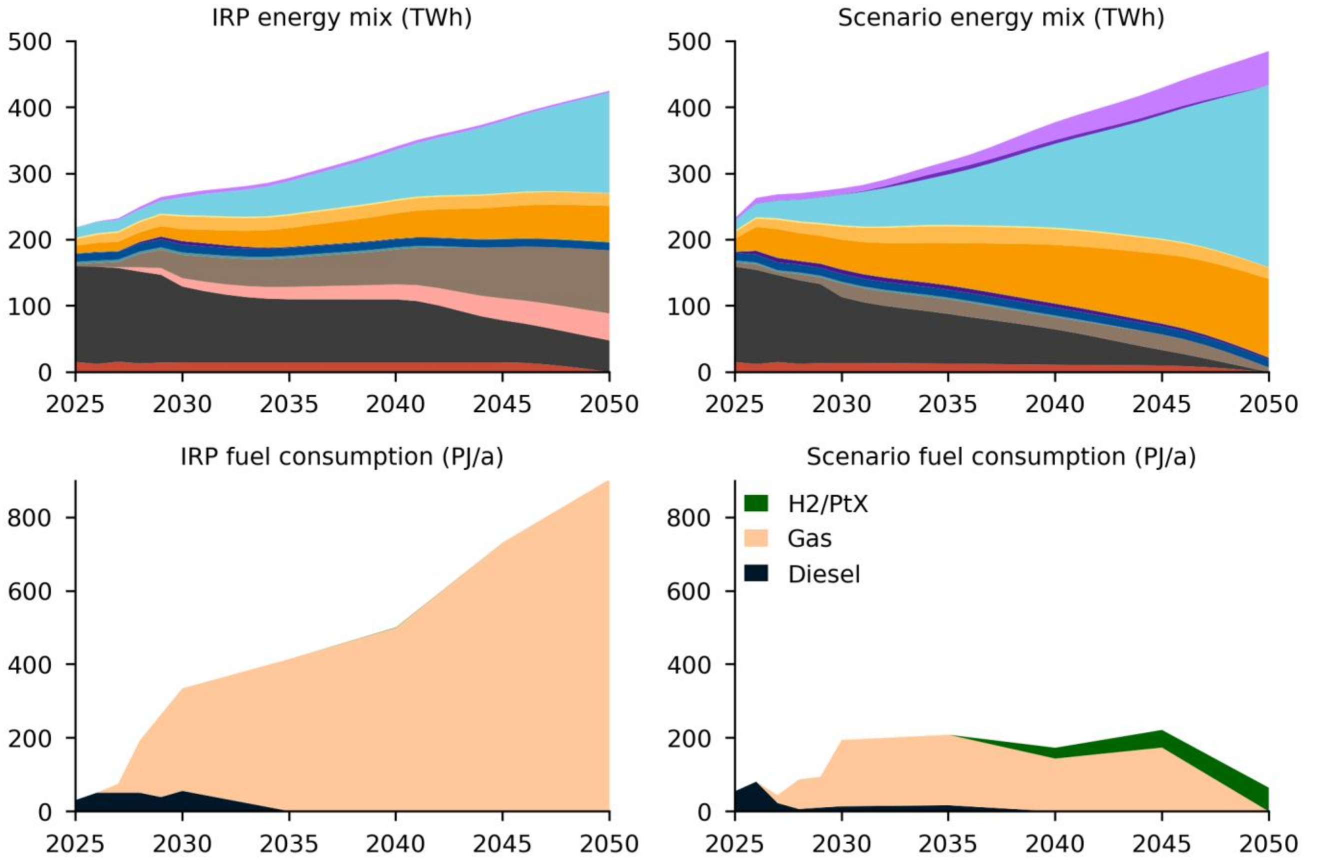


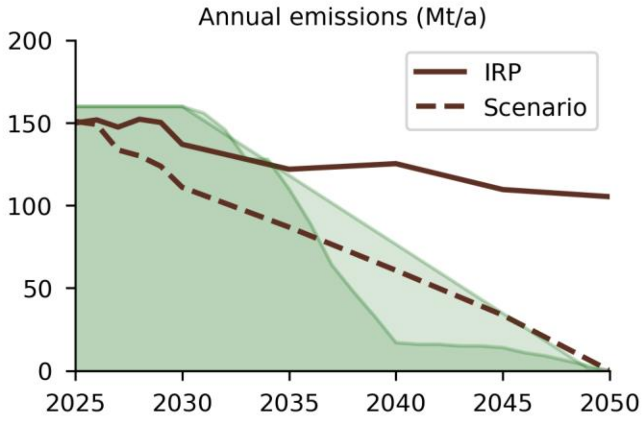
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-79.1% -58 TWh	+0.0%	-40% -1300 Mt
(-5150 R'bn)	(+2 R'bn)	(-375 R'bn)

TARGETED SOLAR, NZ2050

Cumulative new capacity from 2024



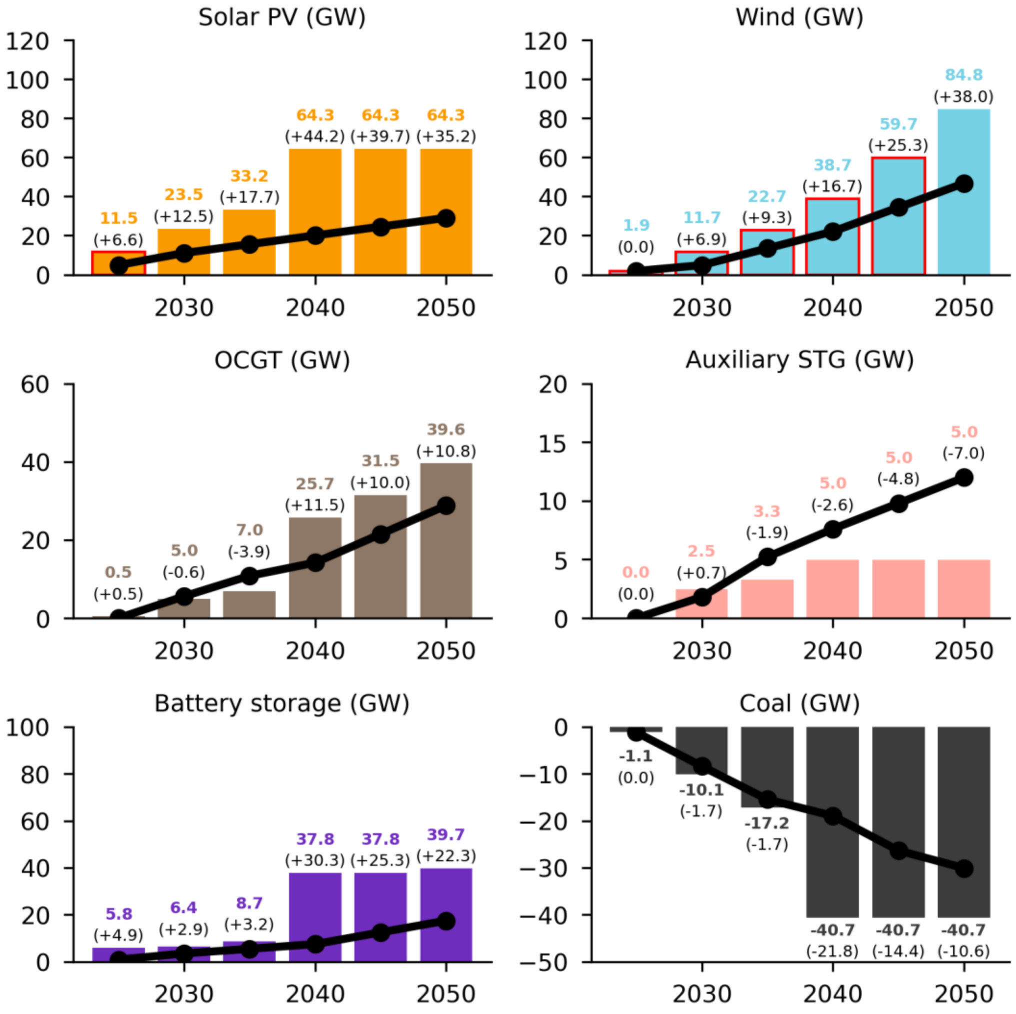


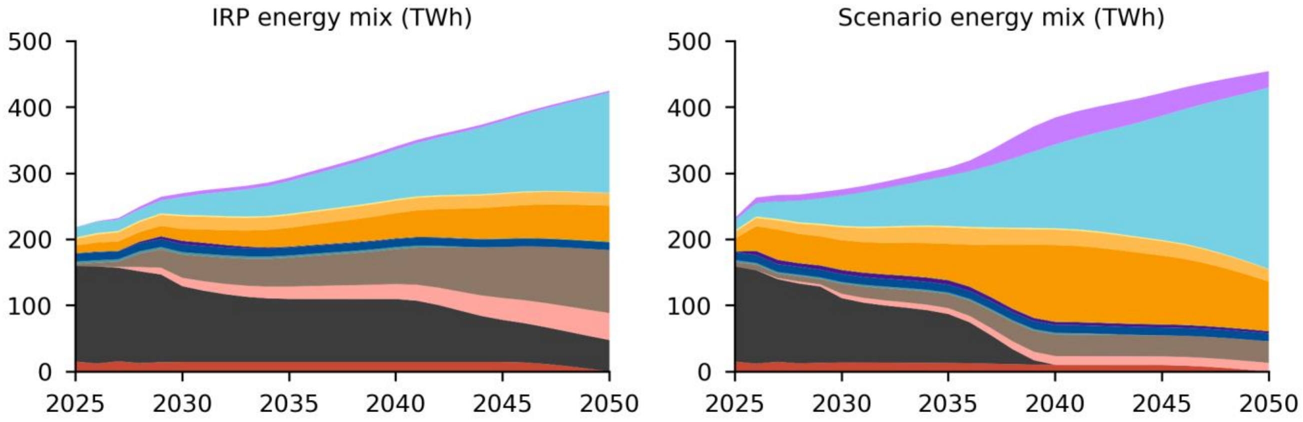


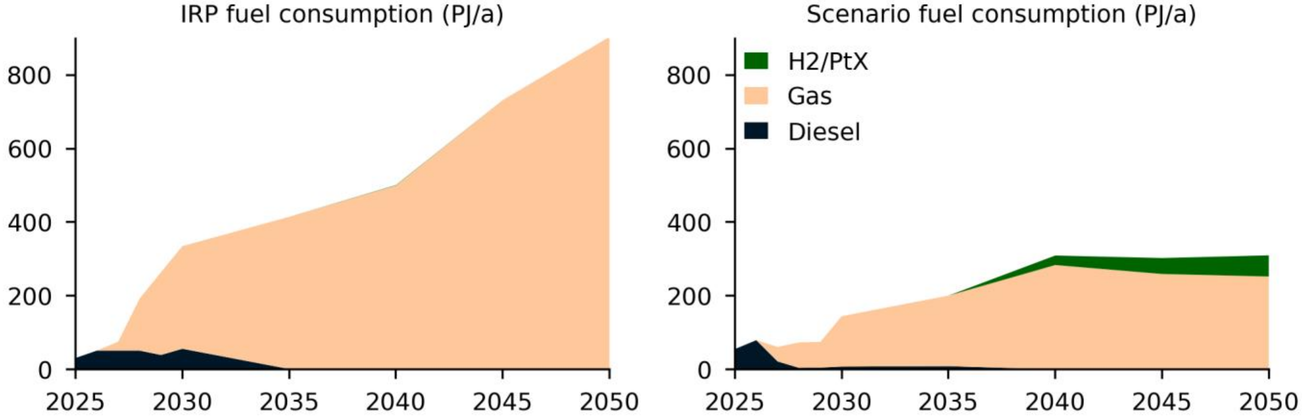
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-79.3% -58 TWh	+5.3%	-40.8% -1326 Mt
(-5163 R'bn)	(+201 R'bn)	(-382 R'bn)

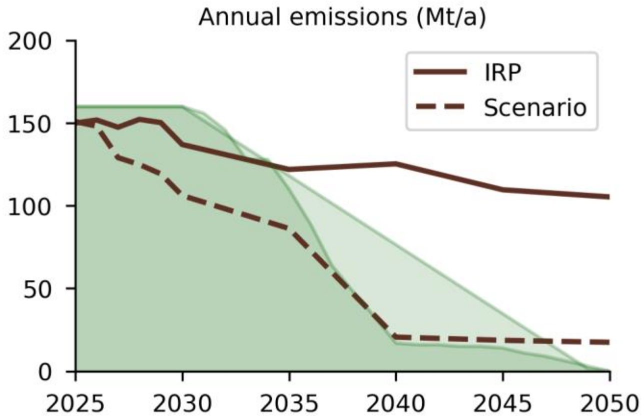
TARGETED SOLAR, PRICE ON CARBON (COAL OFF BY 2040)

Cumulative new capacity from 2024





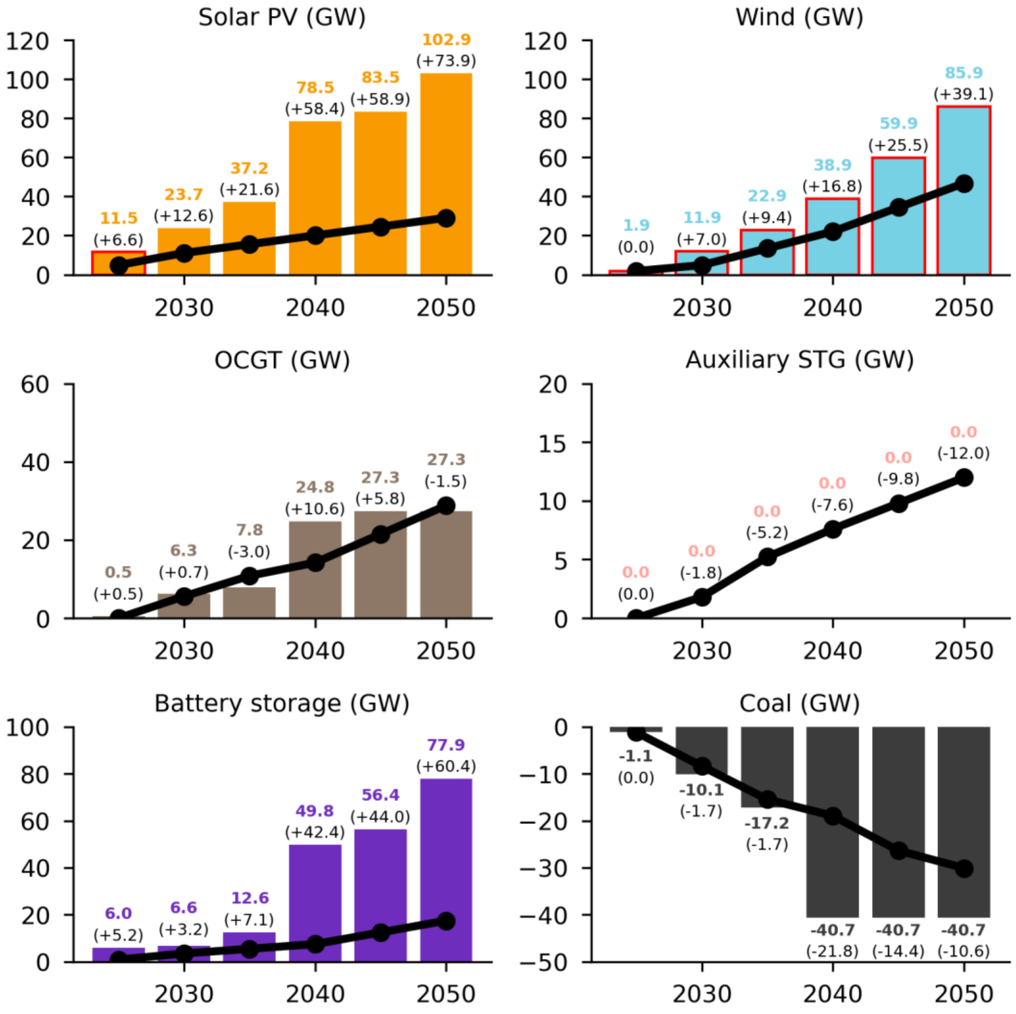


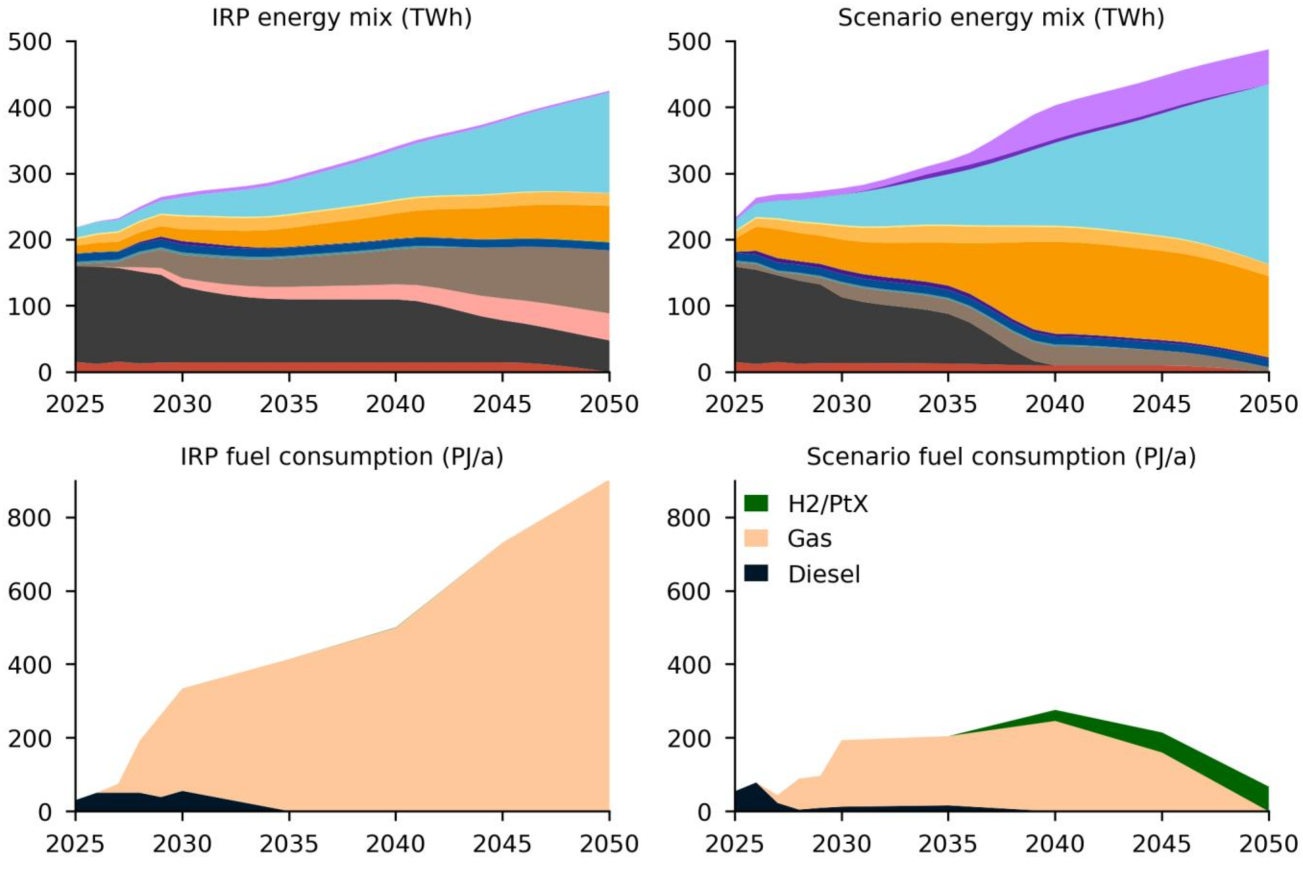


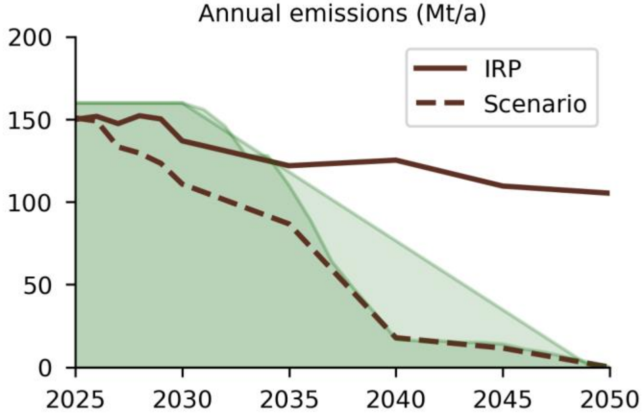
Load shedding	PV of costs 2025-2050	Cumulative Emissions
-79.3% -58 TWh	+3.2%	-49.1% -1596 Mt
(-5162 R'bn)	(+122 R'bn)	(-461 R'bn)

TARGETED SOLAR, NZ 2050, 9GT BUDGET (COAL OFF BY 2040)

Cumulative new capacity from 2024





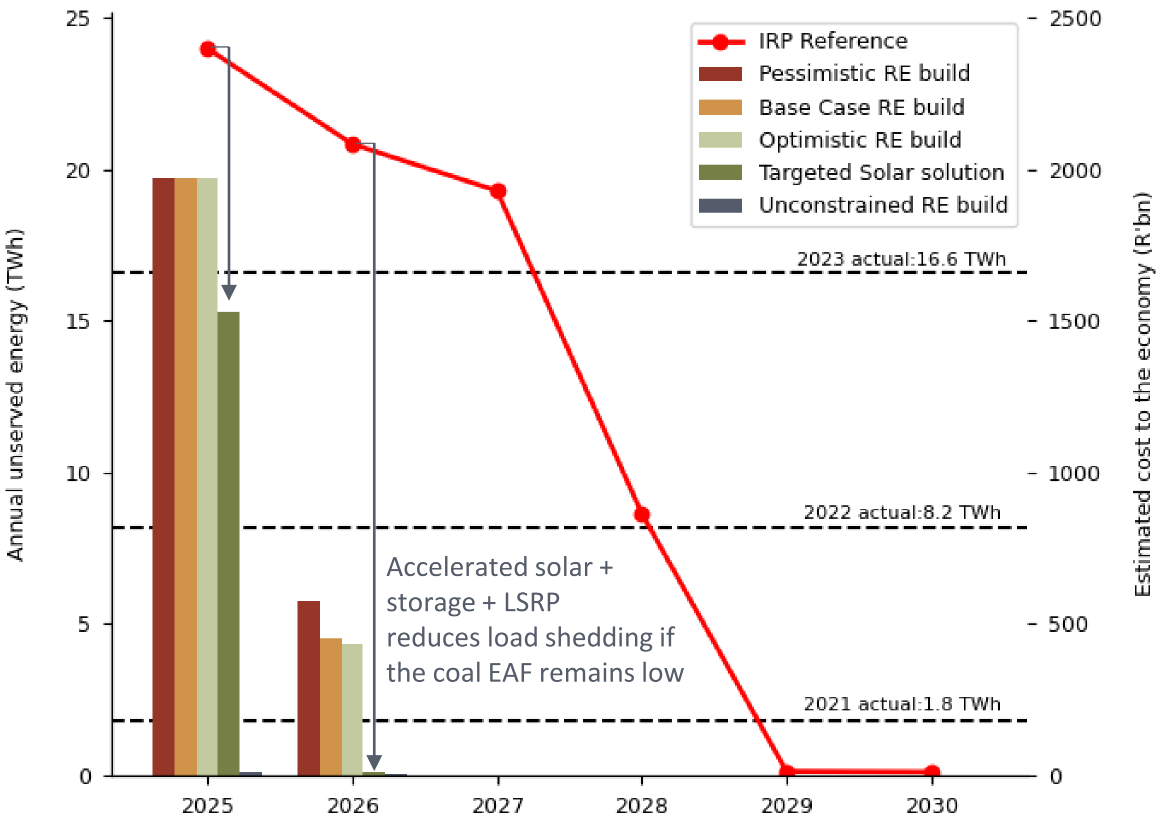


Load shedding	PV of costs 2025-2050	Cumulative Emissions
-79.2% -58 TWh	+9.1%	-51.1% -1663 Mt
(-5159 R'bn)	(+346 R'bn)	(-479 R'bn)

Summary of key modelling findings

SUMMARY OF LOAD SHEDDING IN EACH SCENARIO

COUNTING THE COST OF INSECURE SUPPLY IF THE COAL FLEET CONTINUES TO UNDERPERFORM

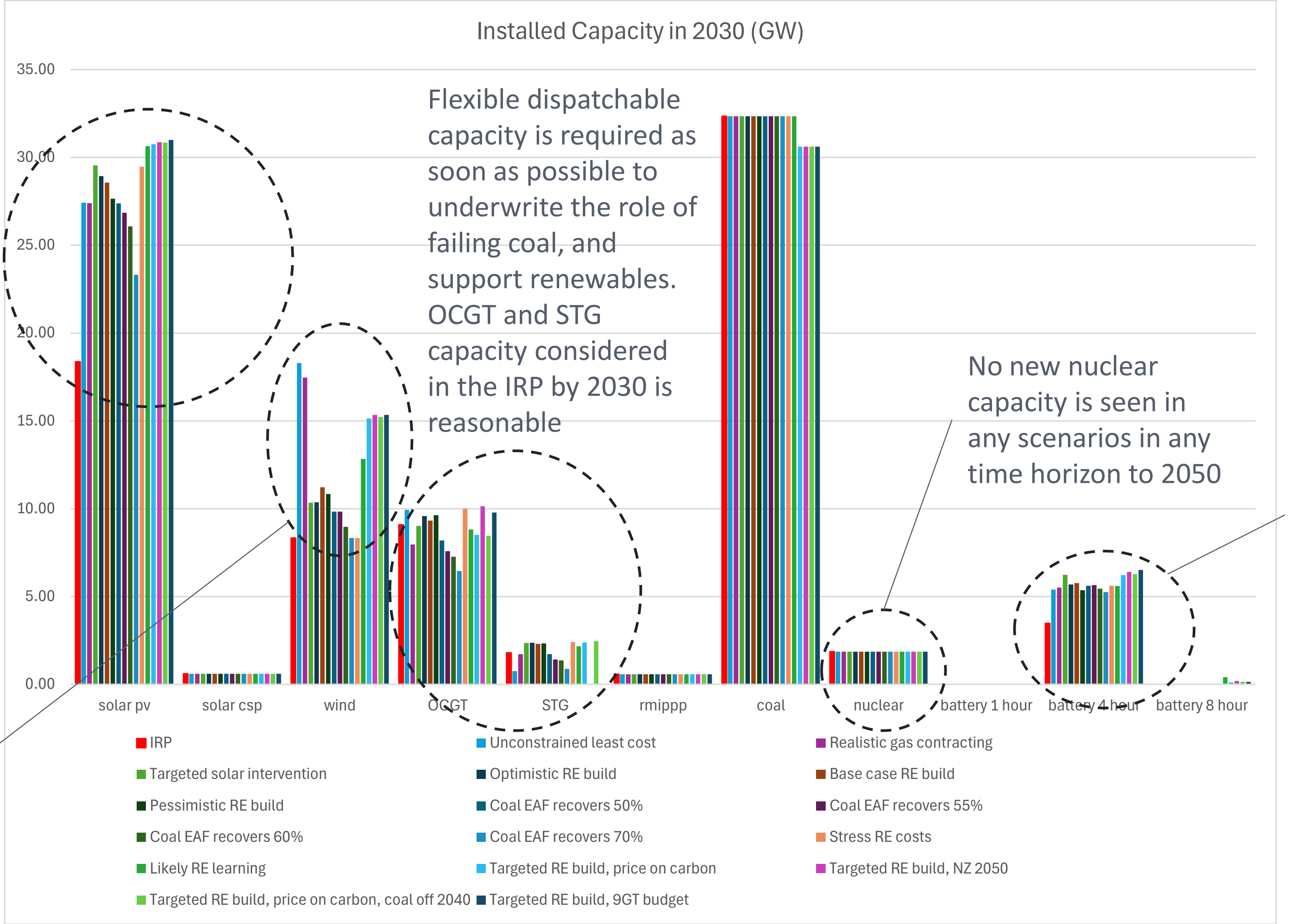


- The assumed availability of the coal fleet in the IRP 2023 is in the order of 43% for Horizon 1, which is comparable to what materialised in 2023 (if not slightly lower).
- The results show that should this low EAF materialise, there is a sustained risk of load shedding in 2025/2026.
- Accelerating the roll out of solar PV and battery storage in the short-term is critical to provide insurance against poor coal performance and to diversify risk. This is a no-regret move as this capacity is required anyway by 2030.
- Additional short-term dispatchable capacity that can be contracted in 2025 and 2026 (e.g. Eskom LSRP*) is also necessary to replace capacity lost in the RMIPPPP.
- Any delays to procurement of gas generation from 2027 onwards pose a significant threat to energy security if these additional measures are not pursued.

*LSRP – Eskom's Load shedding reduction programme

KEY TAKEAWAYS ACROSS SCENARIOS FOR THE PERIOD TO 2030

In **all** scenarios solar capacity far exceeds IRP. An **immediate**, targeted intervention to massively increase installed solar pv is a no-regret move.



Battery capacity across scenarios is roughly double that considered in the IRP. Rapid additional rollout of batteries to support solar intervention and grid relief is required.

Optimal Wind capacity exceeds IRP in all scenarios. Focused attention on removing constraints to new wind capacity is required.

NEW CAPACITY REQUIRED BY 2030

MORE SOLAR FASTER, MORE WIND AND BATTERIES THAN CONSIDERED IN THE IRP

- New solar capacity should be more than doubled from 11GW to at least 21GW – 24GW. This capacity should be built as soon as possible likely requiring a targeted intervention to achieve pace and scale.
- New wind capacity should also be doubled with 7GW to 12GW required as opposed to 5GW in the IRP.
- New battery capacity should be increased by 70% to 80% from the 3.5GW of the IRP to 6-7GW
- OCGT and auxiliary STG capacity in the IRP is reasonable to 2030. Gas contract term and offtake commitments pose stranding risks and should be minimised

		Additional new capacity required by 2030 (GW)			
	Current Installed Capacity (GW)	IRP 2023	Base Case	Targeted Solar Intervention	Targeted Solar Intervention & Net Zero
Solar PV[1]	7.3	+11.1	+21.3	+22.2	+23.6
Wind	3.5	+4.9	+7.8	+6.9	+11.9
OCGT	3.8	+5.6	+5.8	+5.5	+6.6
Auxiliary STG	0.0	+1.8	+2.3	+2.4	0
Battery[2]	0.02	+3.5	+5.7	+6.2	+6.6
Load shedding (TWh)		73	24	15	15

-67%

-79%

[1]Includes REIPPPP and distributed

[2]Predominantly 4h storage capacity

DISPATCHABLE CAPACITY REQUIREMENTS

ACCELERATING FAILURE OF THE COAL FLEET COUPLED WITH DELAYS IN NEW RENEWABLE ENERGY CAPACITY HAVE CHANGED THE ENERGY LANDSCAPE IN TERMS OF THE REQUIREMENT FOR DISPATCHABLE CAPACITY

Changing energy landscape : Our previous studies[1] envisaged a limited role for mid-merit gas fired power generation in the late 2030s, with the immediate primary need for flexible capacity to operate in a peaking role. Whilst the flexible capacity required by 2030 remains similar to our previous work, the (short term) role for this capacity has changed given critical recent changes to the energy landscape:

- Coal fleet collapse - A significant amount of anticipated coal generation is no longer available (~15% lower EAF to 2030). This loss of existing coal capacity in the system is a significant driver of the requirement for higher capacity factor dispatchable capacity.
- Inadequate RE build rate – Failed and delayed procurements and more binding grid constraints than anticipated (especially affecting wind) make the prospect of our previous estimates of 2030 installed capacity (21GW wind, 39GW solar) likely unattainable (most optimistic wind by 2030 now ~15GW). This results in more reliance on solar with the need to generate additional energy outside daylight hours. Although extensive battery storage is deployed prior to 2030, it is cost optimal to augment this with some dispatchable generation that has a higher capacity factor than previous "peaking gas".

Impact of realistic gas contracting: Feedback from various gas sector experts has been incorporated into the updated modelling presented in this work – there is little overlap between gas offtake associated with a peaking role and what can be contractually achieved. If gas is to be used at all, necessarily some of the flexible capacity must run at higher capacity factors than is theoretically economically optimal. Comparing the Unconstrained (slide 40) and Realistic Gas Contracting (slide 42) scenarios reveals that the CCGT capacity is increased by 140% when realistic gas supply contracting is modelled. It would be infeasible both practically and from a cost perspective to fuel this higher capacity factor requirement with diesel.

Flexibility of CCGTs: Questions remain over the flexibility that is technically possible from the auxiliary steam generators of a CCGT. In our current model it is assumed that this capacity can be kept on "hot-standby" during daylight (i.e. solar generation) hours, producing limited/no power. If this is not feasible from a technical perspective, then there would likely be a reduction in the deployment of CCGTs.

Net Zero Scenarios: Our two scenarios that are constrained to zero emissions by 2050 suggest no auxiliary steam generation is feasible (i.e. OCGT only), despite significant gas use (~200PJ/a) for fifteen years. This results from simplifications in our modelling and it would likely be economic to install and run auxiliary steam generators for some years, even if retired early as optimal OCGT use becomes more intermittent. The overall gas requirement would be lower in this case.

[1] A Vital Ambition and Hot Air about Gas

Conclusions and Recommendations

THE IRP 2023 IS NOT ADEQUATE OR TRANSPARENT AND ARRIVES AT INCORRECT AND ECONOMICALLY DAMAGING CONCLUSIONS

- Our analysis has demonstrated that the IRP 2023 is an opaque document which does not achieve its own stated purpose and objectives of ensuring a secure, affordable and clean power system.
- Our investigation suggests that a combination of methodological problems and inappropriate assumptions are to blame:
  - The failure to perform system capacity optimisation for Horizon 1 and therefore the implicit assumption that there is nothing further that can be done about loadshedding in this decade precludes the possibility of relieving the crisis sooner.
  - Furthermore, the “Emerging Plan” from Horizon 1 relies heavily on failed or failing Karpowership gas and REIPPPP BW5 projects, meaning loadshedding under the plan is in fact more than three times as severe as published in the IRP 2023.
  - Unrealistic technology cost assumptions together with the undisclosed inclusion of extremely low renewable energy build constraints mean that the analysis does not establish a credible least cost benchmark against which to consider trade-offs between planning objectives.
  - Predetermined technology mix pathways in Horizon 2 together with the effect of its inappropriate technology cost assumptions obscure the options available to South Africa and produce fatally flawed conclusions.
  - The coal plant retirement schedule remains unquestioned over the second planning Horizon, despite coal being a highly polluting, unreliable and increasingly expensive technology.
- As it stands, the IRP 2023 conflicts with South Africa’s existing climate, green industrialisation, air quality and de facto nuclear policy (the nuclear RfP), without pointing out this fact (except for the minimum emissions standards) or providing a rationale for why existing policies should be changed.
- Together these findings lead to the inevitable conclusion that the IRP 2023 is an inadequate planning document that does not provide a sound basis on which to meaningfully consult with stakeholders and subsequently finalise this critical update to South Africa’s high-level power supply policy.

A TRANSPARENT, METHODOLOGICALLY SOUND ANALYSIS THAT ACHIEVES THE PLANNING OBJECTIVES IS REQUIRED

- Cost and technology assumptions should be transparently benchmarked against credible data sources
- 'Real life' or other constraints and inputs to the model (such as grid capacity, technology build rates and coal plant performance) should be documented, explained, and the sensitivities explored
- A 'middle ground' principle should be used to shape a 'realistic' base case for comparative purposes.
- Capacity optimisation should be implemented throughout the planning horizon to 2050 and all scenarios should meet the security of supply requirements (a minimum unserved energy threshold)
- Each scenario should be compared against the planning objectives of adequate (secure), affordable (least cost) and clean power.
- Policy alignment (climate) should be explored quantitatively by imposing limits in model scenarios.
- The high level of uncertainty over the planning horizon should be foregrounded in interpreting model outcomes.
  - The current power sector environment is highly uncertain, with the global energy sector in a period of disruptive change and transition. Locally, this is exacerbated by uncertainties over the performance of the coal fleet, grid availability, regulation and policy.
  - Successful planning in contexts of high uncertainty prioritises near term development of optionality and the building of system resilience.

OPTIMISING FOR THE FASTER ELIMINATION OF LOAD SHEDDING REQUIRES ACCELERATING SOLAR PV AS A NO-REGRET SOLUTION

- **An accelerated Solar PV build coupled with a moderate increase in battery storage responds extraordinarily well to both the planning objectives of affordable, reliable and clean power, as well as the uncertain planning context:**
  - Such a build plan is the fastest pathway to end load shedding
  - An accelerated PV build acts as an insurance against gas build delay, ongoing poor coal fleet performance and other unforeseen events
  - This pathway has little cost implication over the IRP 2023 Horizon 1 emerging plan
  - A front-loaded PV-dominant system realises valuable decarbonisation gains upfront, as well as putting net zero within reach.
  - PV and batteries are inherently flexible and modular, enabling installation at multiple scales, across the country and by different types of entities
- To enable this outcome multiple interventions are required:
  - Overcome the structural flaws in existing wheeling systems by implementing better wheeling paradigms– such as Token Wheeling – to unlock wheeling into municipalities and reach most customers and generators, irrespective of size or location.
  - Loadshedding policies (NRS048 – 09 load curtailment rules) should be updated to further incentivise onsite generation as well as allowing curtailment benefits from wheeled dispatchable power.
  - A Feed-in-Tariff or similar incentive should be initiated for a limited period, particularly as the loadshedding avoidance incentive for private investors into new residential, commercial and industrial PV installations abates.
  - Progressive municipal-level PV support programmes such as those of the City of Cape Town should be replicated across municipalities throughout the country.
  - If Token Wheeling is fast tracked the need for feed-in tariffs in municipalities can be replaced by allowing the issuance of tokens at appropriate Eskom Standard offer rates
  - REIPPPP procurement should be appropriately adjusted for accelerated Solar PV and battery roll-out.
  - Technical assistance initiatives, possibly supported by JETP or other donor funding, should be put in place to assist distributors to prepare their grids for a large roll-out of roof-top PV and batteries.

A PLAN FOR FASTER ELIMINATION OF LOAD SHEDDING AT AN AFFORDABLE COST IS WELL ALIGNED WITH PATHWAYS TO ZERO

- There is only a moderate difference between the near-term build rates for scenarios that prioritises the elimination of load shedding and those that additionally aim to continue decarbonization to reach Zero by 2050. A comparison between the Targeted Solar Intervention and Targeted Solar NZ2050 show that:
  - both require approximately 23 GW of solar PV and approximately 6.5GW of batteries by 2030 (while the Targeted Solar, NZ2050 battery expansion escalates dramatically thereafter).
  - the Targeted Solar NZ2050 scenario builds more wind power at a rate equal to the build constraints imposed (6.9GW vs 11.9GW).
- The cost premium of a fully net zero power system by 2050 over the IRP reference case is modest
- Ambitious but achievable RE + storage build rates between 2030 and 2040 make it feasible to decommission coal fired generation by approximately 2040, thereby providing more time for the rest of the economy and harder to abate sectors to decarbonise and achieve Net Zero.
- Local air pollution (and the health impact on residents) is associated with the extent to which electricity is produced from coal. The less coal burnt, the better local air quality.

LIMITED MID-MERIT GAS CAPACITY NOW SENSIBLE AS INSURANCE

ACTUAL GAS USAGE IS FAR LOWER THAN THE IRP 2023 VOLUMES

- There have been significant context changes since the IRP 2019: the failure of the coal fleet, stalled renewables build, grid constraints, and the resulting loadshedding
- As a result, procurement of 6GW of dispatchable flexible capacity by the end of the decade - as in the IRP 2023 Horizon 1 emerging plan - is sensible *as an insurance mechanism* against the failure of coal and potential challenges to RE build. Actual gas usage in our analysis is significantly lower over the modelling timeframe than that of the IRP 2023.
- As an insurance mechanism, this *capacity* should be built and contracted with *flexibility as a priority* - the gas usage committed to should be as low and as short term as possible, within the confines of what is contractually possible at a reasonable price.
  - If global decarbonization accelerates, demand for gas is likely to remain below 200PJ, making it optimal to shift away from gas to additional low-cost renewables / batteries, or to fuel switch to hydrogen and/or green liquid fuels (i.e. methanol).
  - The high level of uncertainty over the planning horizon (“Horizon 2”) places a high premium on retaining flexibility on the use of dollar denominated fossil fuels.
- **Notwithstanding the recommendation above our view is that the extreme over-reliance on gas burn of the IRP 2023, especially in the short term, puts the system at high risk of additional loadshedding.**

ADDITIONAL NEXT STEPS REQUIRED TO ADDRESS THE POWER SYSTEM NEEDS

- The amount of load shedding is highly sensitive to the coal plant availability and therefore the amount of coal burnt. This also affects local air quality (human and environmental health impacts) and green house gas emissions. It is likely that a reasonable trade-off between load shedding reduction, health and environmental impacts will entail the adoption of an accelerated renewables pathway (such as a Targeted Solar Net Zero scenario), while investing systematically in improving the EAF of key mid-life and newer power stations.
- Wind power is fundamentally constrained by grid capacity limits. Nevertheless, deployment up to grid capacity limits including curtailment, is economically rational and all the necessary measures should be implemented to enable this to proceed.
- Battery storage is expected to play a very large role in the power system starting immediately for the near-term Horizon 1 period and exponentially so in the post 2030 Horizon 2 period. Installed battery capacity by 2030 of 6.5GW should be targeted – approximately double that envisaged by the IRP2023. Thereafter storage capacity should increase exponentially. This is before mobility (EV) needs for batteries have been considered. This reality will require urgent adjustments to existing policies.
- Long-term large volume gas contracts are high-risk, high-cost options that should be avoided
- With the currently available commercially proven technology options, new nuclear power is not an economically viable or valuable option for the South African power system and should be avoided.

SUMMARY OF KEY RECOMMENDATIONS FOR THE POWER SYSTEM

- Take the necessary steps to dramatically **accelerate solar PV and battery** roll-out by all players, at all scales and locations to accelerate the elimination of load shedding
- Enable and fast track the **procurement of dispatchable peaking and smaller scale mid-merit** capacity while retaining long-term flexibility for its use. This can include IPPO, Eskom and private procurements (will require changes to NRS048-9 to allow wheeling).
- While expediting grid capacity, take the necessary steps to **accelerate wind power deployment** (by all players) up to grid and economic curtailment limits
- Given the large impact of even small coal plant EAF improvements, invest strategically and systematically in **improving the EAF of key mid-life and newer stations**. This is likely to be a more effective and economic option than the alternative of attempting to life-extend old, smaller stations.
- **Do not proceed with the procurement of new nuclear power** until flexible, environmentally sustainable, commercially proven, cost competitive options become available.

CONTACT US

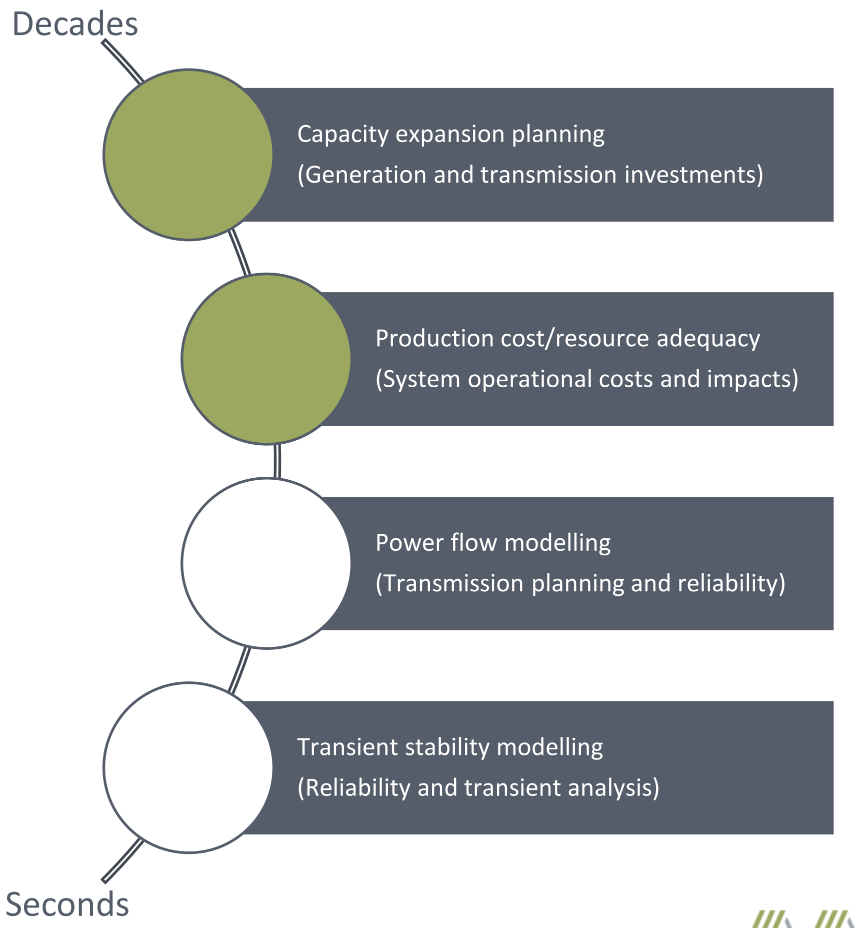
Suite EB04, Tannery Park,
23 Belmont Road, Rondebosch, 7700
+27 21 200 5857
janet.cronje@meridianeconomics.co.za
meridianeconomics.co.za

Technical Appendix

POWER SYSTEM EXPANSION PLANNING MODELLING FRAMEWORK

- Meridian Economics has used an open-source energy system modelling software PyPSA-RSA. The model is fully open-source and can be used to conduct capacity expansion planning studies at differing spatial and temporal resolution for the South African power system.
- Historically, commercial tools have been extensively utilized by both governments and utilities to develop power system capacity expansion plans.
- The modelling conducted by (or for) the DMRE for the IRP has utilized the commercial software PLEXOS.
- One of the challenges of utilizing such commercial tools to support transparent energy policy is the closed nature of the models, which are essentially a 'black-box'.
- The accelerating development of open-source energy system modelling tools in recent years has now reached the point where it opens a credible alternative approach to closed source exclusivity. This builds confidence in results by enabling more effective peer review of work and therefore more effective feedback loops.

Types of problems PyPSA-RSA can be used to addressed highlighted in green.



Modified from Mileva, Deshmukh. (2020) The GridPath Electricity Modelling Platform

CONFIGURATION OF THE PYPSA-RSA MODEL USED IN ANALYSIS

- PyPSA-RSA can be used to **co-optimize generation and transmission for single or multiple years with perfect foresight (all future years are solved together in one model)**. The model makes use of **freely available and open data** which encourages the open exchange of model data and eases the comparison of model results.
- PyPSA-RSA has been designed to **conduct capacity expansion planning studies at differing spatial and temporal resolutions**. Three different spatial resolutions are available in the model:
  - 1-supply: A single node for the entire South Africa.
  - 10-supply: 10 nodes based on the Eskom Generation Connection Capacity Assessment of the 2024 Transmission Network (GCCA – 2024) regions.
  - 34-supply: 34 nodes based on Eskom 34 supply regions as per the latest GCCA.
- Multi-horizon capacity expansion planning is computationally intensive, and historically the IRP analysis has been based on a single node. A single node model of PyPSA-RSA is used in the current analysis. Meridian Economics is also developing a **Spatially Disaggregated model of the RSA power system** which will co-optimizing generation and broad transmission corridors.
- By default, PyPSA-RSA uses full chronology **(8760h per year)**, but the number of snapshots can be reduced through the use of time-series segmentation through the open-source Time Series Aggregation Module.
- In the current analysis the capacity expansion is run using full chronology in single year steps from 2025 to2030. In the long-term outlook between 2031 and 2050 the model is run in capacity expansion mode for five-year intervals.

INPUTS TO THE CAPACITY EXPANSION PLANNING MODEL

Demand
Hourly profile
Projected growth

Existing Generation and storage technologies
Existing Eskom generators
Eskom plant performance (coal fleet EAF)
Eskom decommissioning
Existing REIPPPP generators
Existing rooftop solar PV
Solar PV/wind hourly profiles
Ramp rates
Heat rates
Emissions intensity

New build Generation and storage technologies
Technology cost assumptions
Learning rates (CAPEX, Fixed and Variable OPEX, Fuel, start-up and shut-down costs)
Technology technical characteristics

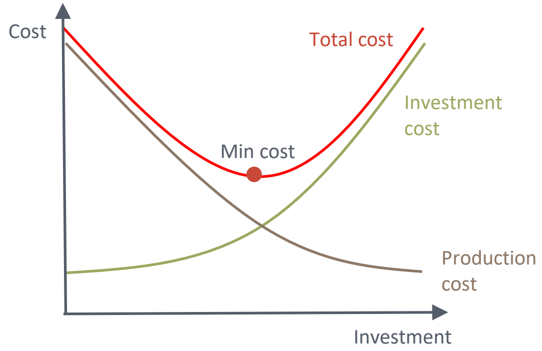
Constraints
Security of supply and system adequacy
Emissions limits – CO_2
Technology new build constraints (grid impact)
Gas contracting

PyPSA modelling framework
Least cost optimisation

Capacity expansion plan
Installed capacity mix of technologies (MW)
Decommissioned capacity (MW)
Energy share per technology (TWh)
Unserved energy/load shedding
Curtailment

Costs
Total system costs
Investment and Operation costs
Average tariff path (c/kWh)

Emissions trajectory



Minimise sum of annualised capital costs and marginal costs
Subject to meeting energy demand and other constraints (CO_2 emissions limits, land availability etc)

In the single node model transmission cost are not included (est. 10-15%)

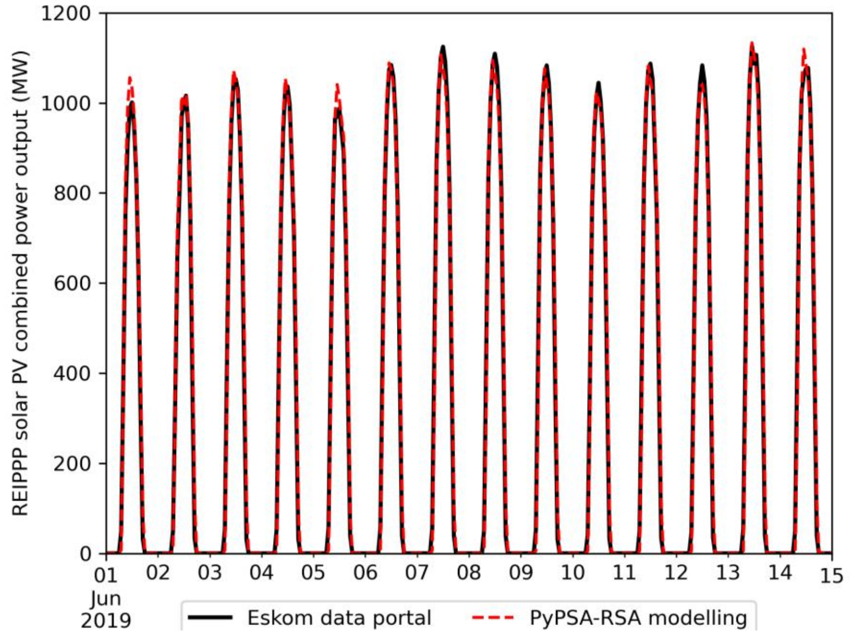
WIND AND SOLAR PV MODELLING

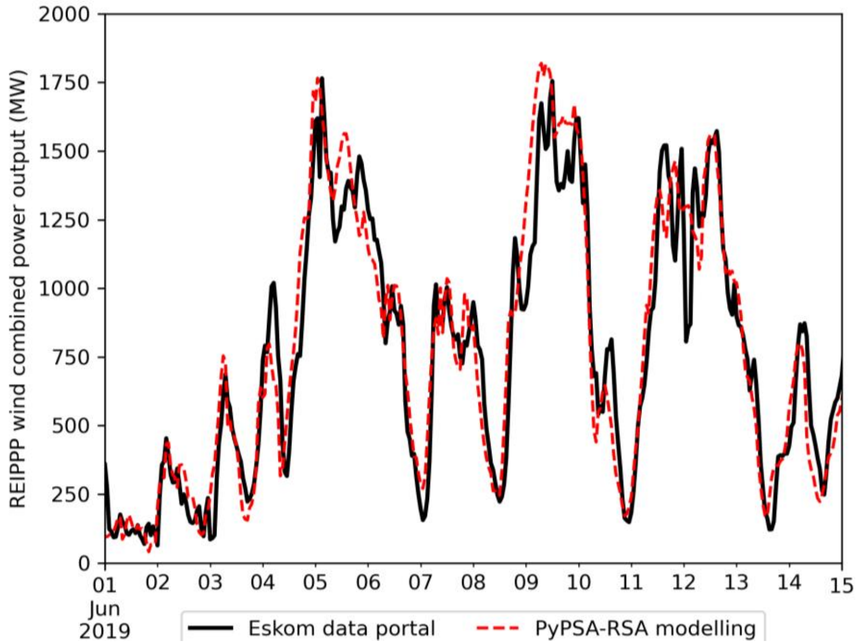
HOURLY GENERATION PROFILES FROM SATELLITE BASED WEATHER DATA

- Hourly generation data for wind and solar PV is a critical input to the IRP modelling process. Currently the IRP relies on data from CSIR/Fraunhofer. The solar data in particular is based on a mix of rooftop solar PV and fixed tilt ground mounted systems, and therefore underestimates the potential of utility scale single axis tracking plants.
- The PyPSA-RSA model uses reputable weather data sources such as (ERA5, Wind Atlas of South Africa, SARAH, NREL National Solar Radiation Database). This input weather data (e.g. wind speed, temperature, global horizontal irradiation, diffuse radiation) is inputted into a power plant model to calculate the output power generation potential.
- For Solar PV technologies the NREL PySAM library is used for the power plant model. For wind a smoothed wind farm power curve model is used based on the data from CSIR/Fraunhofer that incorporates various losses (wake effects, outages etc).

Hourly satellite weather data → Power plant model → Output hourly generation data

- We validate our resource modelling by recreating the existing REIPPPP fleet of generation capacity at each site. As shown in the right side figures the model output agrees very well with the actual Eskom Data.





NEW BUILD TECHNOLOGY COSTS INFORMED BY COMPARATIVE ANALYSIS TO OTHER DATA SOURCES

- Meridian has recently published a comparative analysis of the IRP 2023 cost assumptions here. The comparative data sources included:
- **IRP 2023 data**:
  - IRP 2023 (IRP 2023 technology costs sourced from here. Technology descriptions and cost data are provided under "New Tech Assumptions IRP 2023").
  - EPRI 2021 ("EPRI Report: Supply-Side Cost and Performance Data for Eskom Integrated Resource Planning" sourced from here) – this is the source document for IRP 2023 assumptions, but IRP 2023 assumes no future cost learning. We have applied cost learning from EPRI 2021 to the IRP 2023 values for comparison.
- **Power system studies:**
  - Meridian 2020 (Meridian Economics 2020 report A Vital Ambition in collaboration with the CSIR Energy Centre sourced from here).
  - JET-PMU 2022 (Just Energy Transition Project Management Unit, South Africa's Just Energy Transition Investment Plan (JET IP) for the initial period 2023-2027 sourced from here).
  - NBI 2021 (National Business Institute, Climate Pathways sourced from here).
- **Technology cost assumption sources:**
  - AEMO 2023 (Australian Energy Market Operator 2023, Draft Integrated System Plan sourced from here) – includes comprehensive technology input assumptions to the Australian Integrated System Plan ISP 2024.
  - ATB 2023 (National Renewable Energy Laboratory Annual Technology Baseline 2023 sourced from here) – this is focused mainly on the USA market, with Conservative, Moderate and Advanced cost learning estimates.
  - IEA 2023 (International Energy Agency, World Energy Outlook 2023 sourced from here) – includes estimates for 4 jurisdictions (USA, EU, China, India) and 3 scenarios (Stated Policies, Announced pledges, Net Zero emissions by 2050). For brevity only India (Stated Policies) is included in charts. The spreadsheet includes all scenarios for India and EU.
  - REIPPPP (Renewable Energy Independent Power Producer Procurement Programme) – where applicable we have included data from previous rounds of the REIPPPP for comparison.

NEW BUILD CONVENTIONAL TECHNOLOGY ASSUMPTIONS

- The table below summarises the costs and technical characteristics associated with conventional power generation technologies used in the Meridian 2024 Base Case scenario.
- Coal costs derive from EPRI 2021 data.
- Auxiliary STG costs are calculated based on IRP 2023 assumptions.
- OCGT costs are provided for gas and diesel fuel.
- The nuclear capital costs are aligned to IRP 2019 adjusting for inflation.
- No cost reduction (learning) is anticipated for conventional technologies until 2050
- Fuel costs remain constant to 2050. Gas per IRP $15/GJ. Diesel 3x Gas, Green Hydrogen/clean fuel also 3x Gas
- Leakage of 2.5% is assumed in the calculation of gas emissions factor.

Technology	Year	Total Capital Cost [R/kW]	Fixed Operating Cost (FOM) [R/kW/year]	Variable Operating Cost (VOM) [R/MWh]	Fuel (R/GJ)	Heat rate (MJ/MWh)	Efficiency (%)	Carbon Dioxide emmisions (tCO_2/MWh)	Lifetime (years)
		Meridian 2024 Base Case	Meridian 2024 Base Case	Meridian 2024 Base Case	Meridian 2024 Base Case	Meridian 2024 Base Case	Meridian 2024 Base Case	Meridian 2024 Base Case	Meridian 2024 Base Case
Coal	2025-2050	68 943	1 439	40	45	9 776	37%	0.84	30
OCGT Gas/Diesel	2025-2050	12 182	61	78	272/816	9 473	38%	0.65/0.70	30
Auxilliary STG	2025-2050	15 264	41	16	0	0	100%	-	30
Nuclear	2025-2050	115 818	1 646	45	18	11 250	32%	-	60

* It is assumed that in 2040 there is a switch to green liquid fuels thus OCGT Diesel emissions reduce to 0 in 2040 through to 2050.

NEW BUILD STORAGE TECHNOLOGY ASSUMPTIONS

- Variable O&M is assumed to be 0.00 for all four storage technologies

Technology	Year	Total Capital Cost [R/kW]			Fixed Operating Cost (FOM) [R/kW/year]			Maximum hours (hours)	Efficiency (%)	Lifetime (years)
		Meridian 2024 Stress	Meridian 2024 Base Case	Meridian 2024 Likely Learning	Meridian 2024 Stress	Meridian 2024 Base Case	Meridian 2024 Likely Learning	Meridian 2024 Base Case	Meridian 2024 Base Case	Meridian 2024 Base Case
Battery 1hr	2024	13 000	13 000	13 000	390	390	390	1	89%	15
	2030	10 823	8 754	6 917	325	263	207			
	2040	8 984	6 703	5 296	270	201	159			
	2050	8 211	5 930	4 685	246	178	141			
Battery 4hr	2024	28 500	28 500	28 500	855	855	855	4	89%	15
	2030	23 727	19 192	15 163	712	576	455			
	2040	19 695	14 695	11 610	591	441	348			
	2050	18 000	13 000	10 271	540	390	308			
Battery 8hr	2024	51 614	51 614	51 614	1 548	1 548	1 548	8	89%	15
	2030	42 969	34 756	27 461	1 289	1 043	824			
	2040	35 668	26 613	21 027	1 070	798	631			
	2050	32 598	23 543	18 601	978	706	558			
PHS	2024	31 800	31 800	31 800	327	327	327	20	78%	50

NEW BUILD RENEWABLES TECHNOLOGY COST ASSUMPTIONS

- Cost assumptions are provided for the years 2024, 2030, 2040, and 2050.
- Learning trajectories are detailed in the slides that follow.
- All costs are presented in 2023 ZAR, in accordance with the IRP 2023.
- The capacity factor and lifetime remain consistent across the Stress, Base, and Likely Learning scenarios.
- Solar PV costs in IRP 2023 appear unreasonably high and have been adjusted in the current analysis.

Technology	Year	Total Capital Cost [R/kW]			Fixed Operating Cost (FOM) [R/kW/year]			Variable Operating Cost (VOM) [R/MWh]	Capacity factor (%)	Lifetime (years)
		Meridian 2024 Stress	Meridian 2024 Base Case	Meridian 2024 Likely Learning	Meridian 2024 Stress	Meridian 2024 Base Case	Meridian 2024 Likely Learning	Meridian 2024 Base Case	Meridian 2024 Base Case	Meridian 2024 Base Case
Solar PV	2024	17 808	16 911	12 166	356	338	243	0.01	30.9%	25
	2030	15 671	13 662	11 739	313	273	235	0.01		
	2040	15 671	11 384	11 026	313	228	221	0.01		
	2050	15 671	10 314	10 314	313	206	206	0.01		
Wind	2024	29 521	24 797	20 517	590	496	410	0.02	38.9%	25
	2030	29 521	22 916	20 349	590	458	407	0.02		
	2040	29 521	21 365	20 070	590	427	401	0.02		
	2050	29 521	19 791	19 791	590	396	396	0.02		
CSP Tower 9hrs	2024	118 677	118 677	118 677	1 538	1 538	1 538	-	60.0%	30
	2030	98 534	98 534	98 534	1 538	1 538	1 538	-		
	2040	84 133	84 133	84 133	1 538	1 538	1 538	-		
	2050	79 688	79 688	79 688	1 538	1 538	1 538	-		

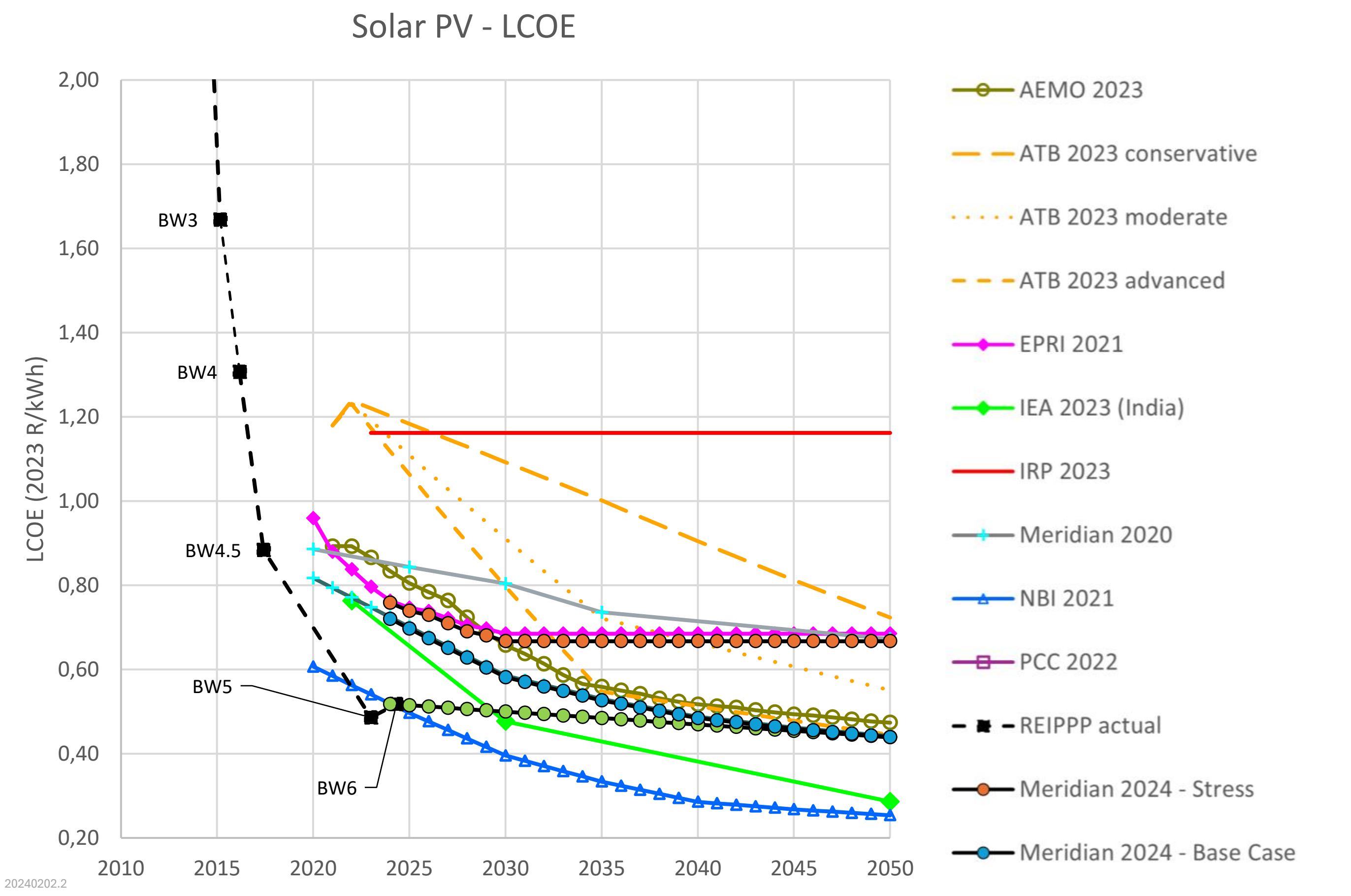
REVISED TECHNOLOGY COST INPUT ASSUMPTIONS

NOTES ON THE CHARTS

- The following slides compare the Meridian 2024 cost input assumptions with technology costs from alternative data sources. Costs are compared based on the LCOE for generation technologies and the Levelised Annual Cost for storage.
- Each data source is associated with a single-coloured line as depicted in the legend on the right. The multiple cost trajectories for Meridian 2024 are represented by different coloured markers.
- The IRP 2023 data is represented by a red solid line for instances where a single technology option has been provided. For instances where there are multiple technology options red dashed lines with markers are used.
- Where multiple IRP 2023 lines are presented the lowest LCOE/Levelised Annual Cost is considered to be the reference technology that is deployed in the PLEXOS model used in compiling the IRP 2023.

REVISED TECHNOLOGY COST INPUT ASSUMPTIONS

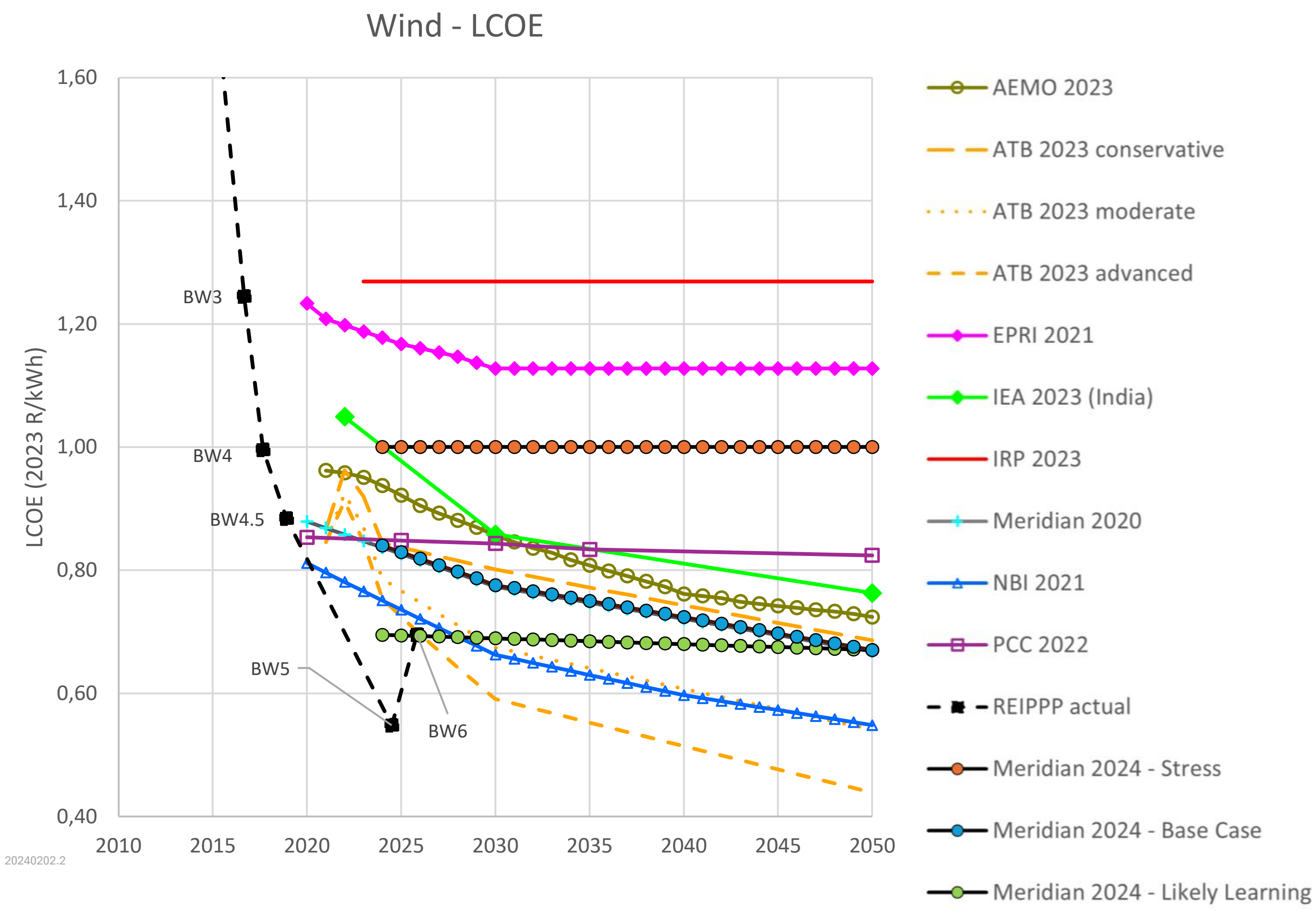
MERIDIAN COST ASSUMPTIONS IN COMPARISON WITH ALTERNATIVE DATA SOURCES



- The LCOE for IRP 2023 is considered unreasonably high, nearly twice as much as the average of BW6 successful bids. Consequently, we have adjusted our solar PV cost assumptions.
- Three cost trajectories for solar PV are considered based on the **Stress**, **Likely Learning** and **Base Case** assumptions. The solar PV generator in the model refers to a mix of centrally procured REIPPPP capacity and private sector investments (utility scale ground mounted, single axis tracking).
- Solar PV prices from REIPPPP BW6 are considered as representative of the latest prices for REIPPPP capacity, underpinned by government guarantees, which lower the financing costs.
- Based on our interactions with large industrial customers, the PPA tariffs that are being achieved for private sector projects are typically higher than that achieved in BW6. It is also possible that shortages on transformer capacity could increase prices. Therefore, our **Base Case** cost assumes an initial premium on BW6 for plants coming online in 2024. These costs then decrease in real terms to 2050, as technology costs decrease, following a trend that is comparable with other data sources such as AEMO 2023.
- In terms of the **Stress** costs, the profile tracks the projected EPRI learning rate, which has an initial starting point in 2024 that is not significantly higher than the base-case. However, the learning rate to 2030 is lower, and no further costs reductions post 2030 are assumed.
- The **Likely Learning** trajectory assumes that there is no premium placed on private sector projects relative to BW6, but a very moderate cost reduction is assumed to 2050, ending at the same cost as the base case.

REVISED TECHNOLOGY COST INPUT ASSUMPTIONS

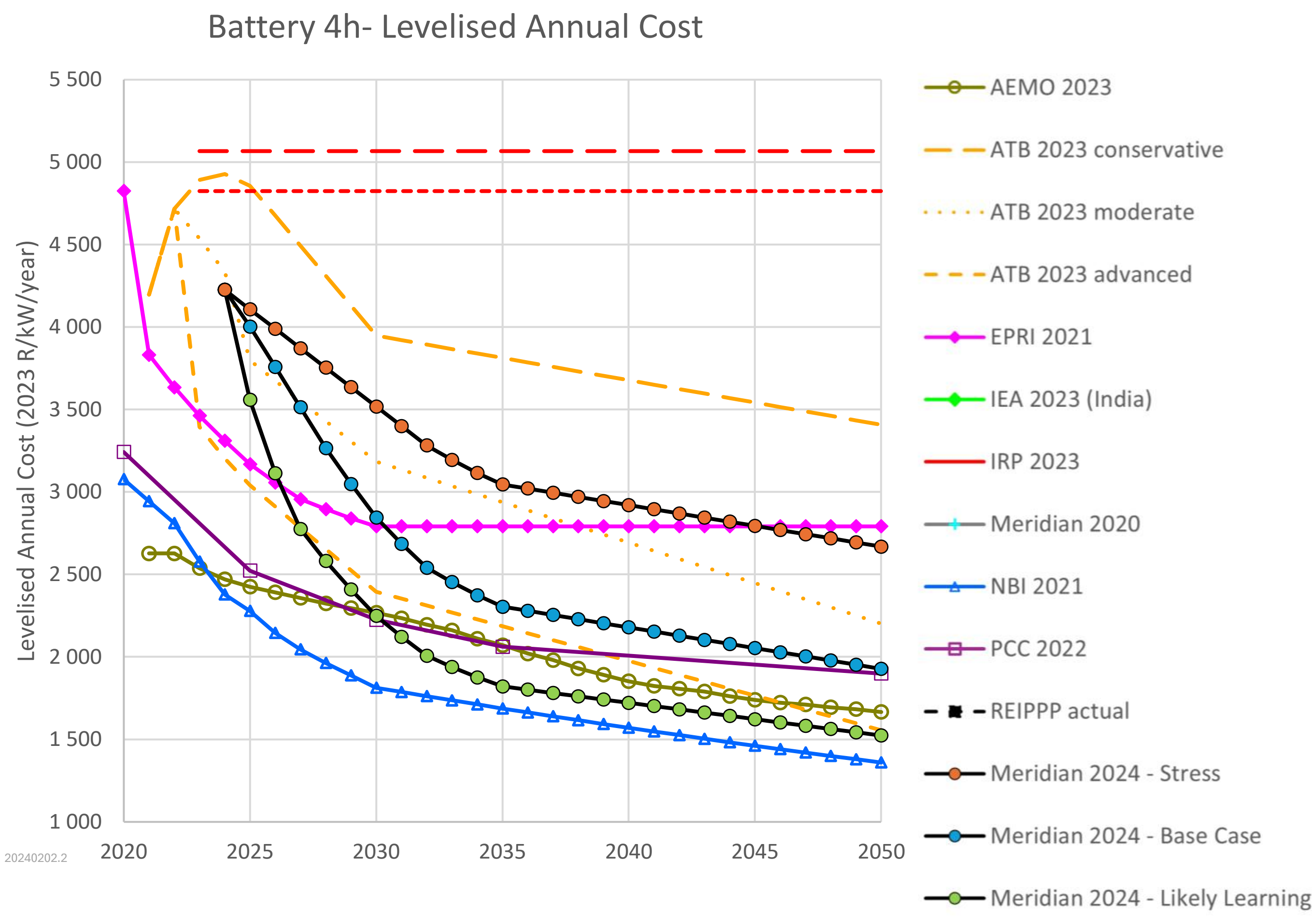
MERIDIAN COST ASSUMPTIONS IN COMPARISON WITH ALTERNATIVE DATA SOURCES



- As with solar PV the LCOE for wind in the IRP 2023 is considered unreasonably high, when compared to bid submissions for BW6 (although none were awarded due to grid constraints). Consequently, we have adjusted our wind cost assumptions.
- Three cost trajectories for wind are considered based on the **Stress**, **Likely Learning** and **Base Case** assumptions. The wind generator in the model refers to a mix of centrally procured REIPPPP capacity and private sector investments.
- Wind prices from REIPPPP BW6 are considered as representative of the latest prices for REIPPPP capacity in high wind resource areas Western and Eastern Cape, which are also underpinned by government guarantees, which lower the financing costs.
- Based on our interactions with large industrial customers, the PPA tariffs that are being achieved for private sector projects are typically higher than that achieved in BW6. Therefore, our **Base Case** cost assumes an initial premium on BW6 for plants coming online in 2024. These costs then decrease in real terms to 2050, as technology costs decrease, following a trend that is comparable with other data sources such as AEMO 2023.
- The LCOE shown in the figure is for wind generators located in high resource areas. We apply a further 15% increase in capital cost and O&M for wind generators in lower resource areas such as Mpumalanga to account for the need for higher hub heights (120-140m) and larger turbine rotor diameters due to the lower wind speeds.
- In terms of **Stress** costs, we assume a very conservative price of R1/kWh across the study horizon. This is intended to test a scenario where global supply chains remain constrained, combined with local supply, logistics and construction issues that are more likely to affect wind than solar PV.
- The **Likely Learning** trajectory assumes that there is no premium placed on private sector projects relative to BW6, but a very moderate cost reduction is assumed to 2050, ending at the same cost as the base case.

REVISED TECHNOLOGY COST INPUT ASSUMPTIONS

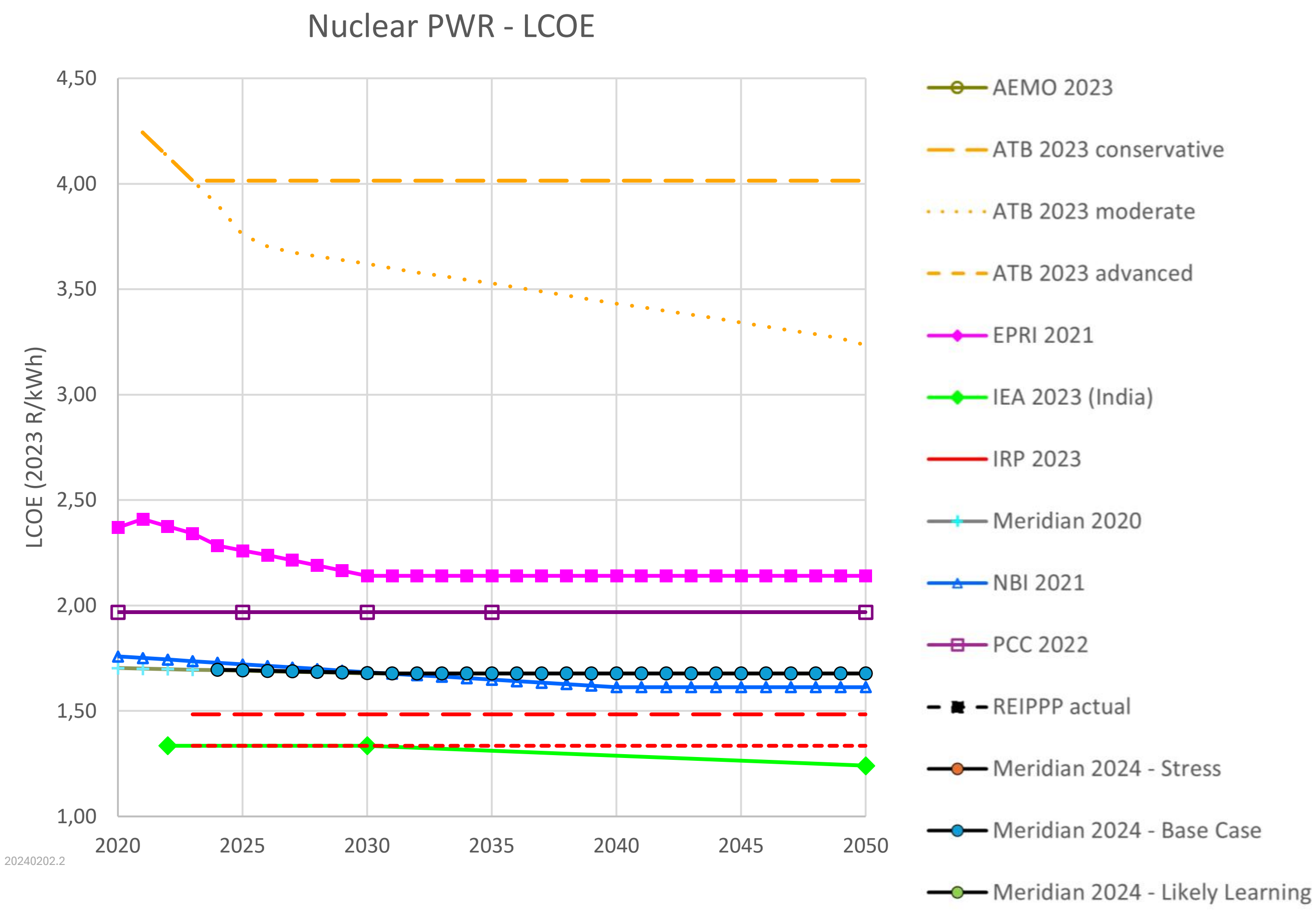
MERIDIAN COST ASSUMPTIONS IN COMPARISON WITH ALTERNATIVE DATA SOURCES



- The failure to account for technology cost reductions in the IRP (even between 2020 and 2023), has a very pronounced effect on the assumed costs for battery storage. If the IRP applied the EPRI cost learnings for batteries the costs would be significantly lower by 2023, even if no future learning was applied. Given the unreasonably high battery storage costs we have adjusted our cost assumptions.
- Three cost trajectories for battery storage are considered based on the **Stress**, **Likely Learning** and **Base Case** assumptions. Although only 4h storage is shown in this slide, we apply the learning rate from 4h battery storage to both 1h and 8h batteries.
- Most sources agree that strong cost reductions in battery storage are likely to materialise over the coming decades. Across all three cases the highest cost reductions are achieved prior to 2035, followed by a more gradual learning rate from 2035 to 2050. The starting point cost in 2024 is aligned with BW1 of the BESIPPPP.
- The resulting costs from our **Base Case** are more conservative than the AEMO, NBI and PCC, whilst our **Likely Learning** case lies between the AEMO and NBI from 2035 onwards.
- Our **Stress** case includes a much more conservative cost reduction profile for battery storage, that is only lower than the EPRI curve after 2045. This case is designed to test the impact on the optimal energy mix if battery storage costs do not materialise as most sources envisage.

REVISED TECHNOLOGY COST INPUT ASSUMPTIONS

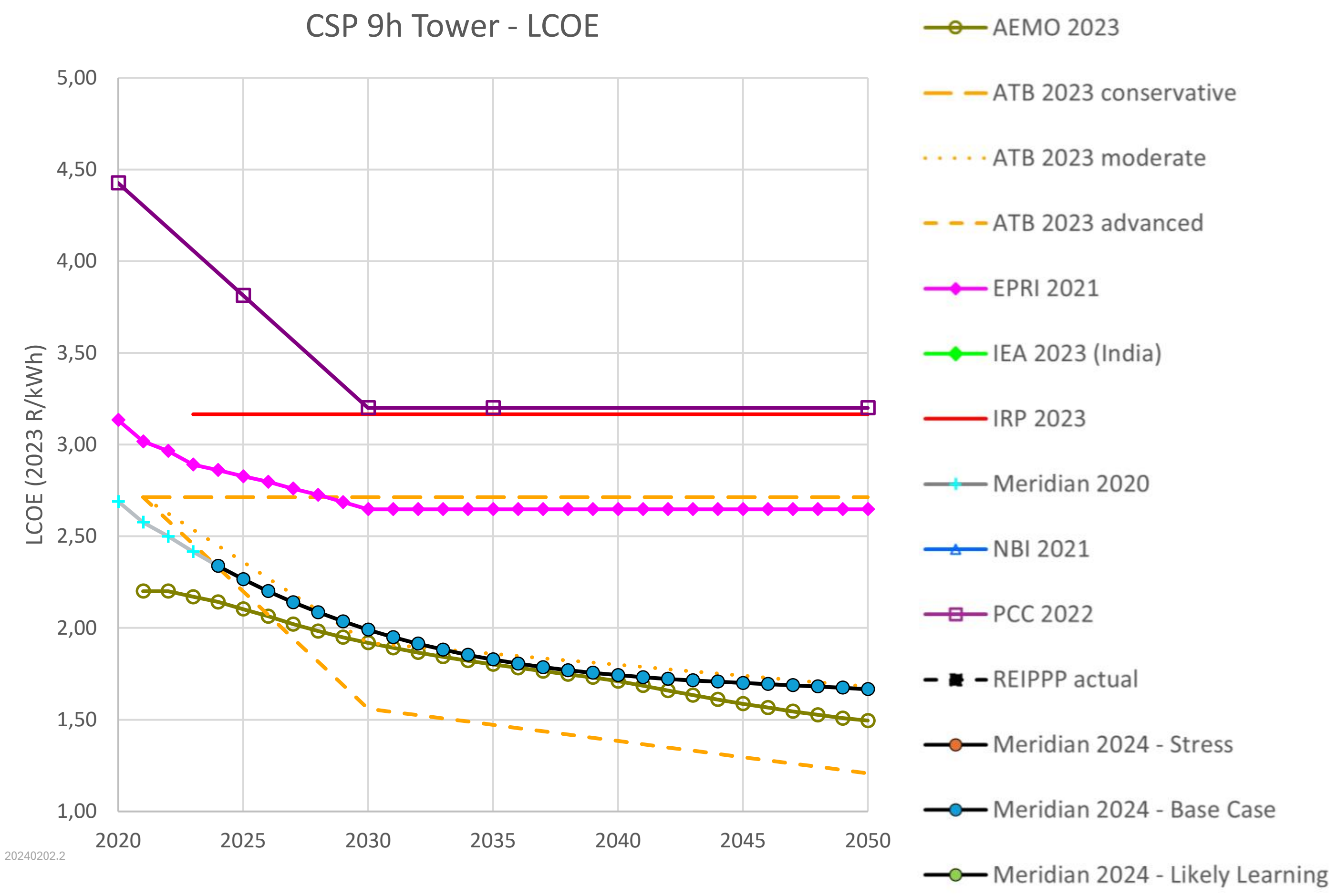
MERIDIAN COST ASSUMPTIONS IN COMPARISON WITH ALTERNATIVE DATA SOURCES



- Unlike other technology categories in the IRP, where costs are generally much higher than other sources (including the EPRI figures when learning is applied) Nuclear is treated differently by the DMRE.
- The DMRE stated that they have modified the nuclear costs based on information received as part of a RFI that was issued to the market. Given the non-binding nature of this RFI, it is questionable to use this information to override the EPRI data. The IRP nuclear costs are lower than all other datasets, except for the IEA data for India which assumes an "nth of its kind" reactor which is replicated from previous projects resulting in cost reductions from previous construction and design. Any new nuclear plants built in South Africa would not benefit from these cost reductions.
- Considering the history of cost overrun and delays in nuclear projects in the UK and US, as well as local mega-projects like Kusile, Medupi and Ingula, these assumptions appear overly optimistic.
- We have therefore modified the cost of nuclear upwards to be aligned with previous IRP 2019 cost data after accounting for inflation. These assumed costs are still significantly lower than the EPRI 2021, NREL, and PCC 2022 references.
- We only include a single **Base** case technology cost for nuclear.

REVISED TECHNOLOGY COST INPUT ASSUMPTIONS

MERIDIAN COST ASSUMPTIONS IN COMPARISON WITH ALTERNATIVE DATA SOURCES



- Concentrating solar thermal costs vary significantly based on the technology (tower or trough), and the amount of thermal energy storage.
- Initial BWs as part of the REIPPPP included CSP up to BW3.5 (awarded in 2015), but no further bid windows have been issued. Therefore, there is little additional market data available to benchmark costs.
- As with solar PV, the IRP assumption for CSP is significantly higher than other credible estimates. CSP cost estimates for our previous work were based on projections for CSP for the initial REIPPPP BWs. When comparing this trajectory to other sources we see it is relatively well aligned with NREL and AEMO.
- We only include a single **Base** case technology cost for CSP, based on a Central Receiver with 9h of storage. Given lack of additional new cost information, we maintain the learning rate of our previous work in 2020.

COST ASSUMPTIONS FOR OTHER CONVENTIONAL TECHNOLOGIES

Coal: Capital and operating costs from IRP 2023 are used assuming a pulverised coal generator with FGD.

Pumped Hydro Storage: Capital costs are aligned to the IRP 2023. Despite the cost over-runs on Ingula the estimated total cost of the project is in line with the IRP 2023 assumption. However, the IRP includes as Variable Operating cost of R545/MWh. It is not clear where this cost originates from and therefore it is not included in our analysis.

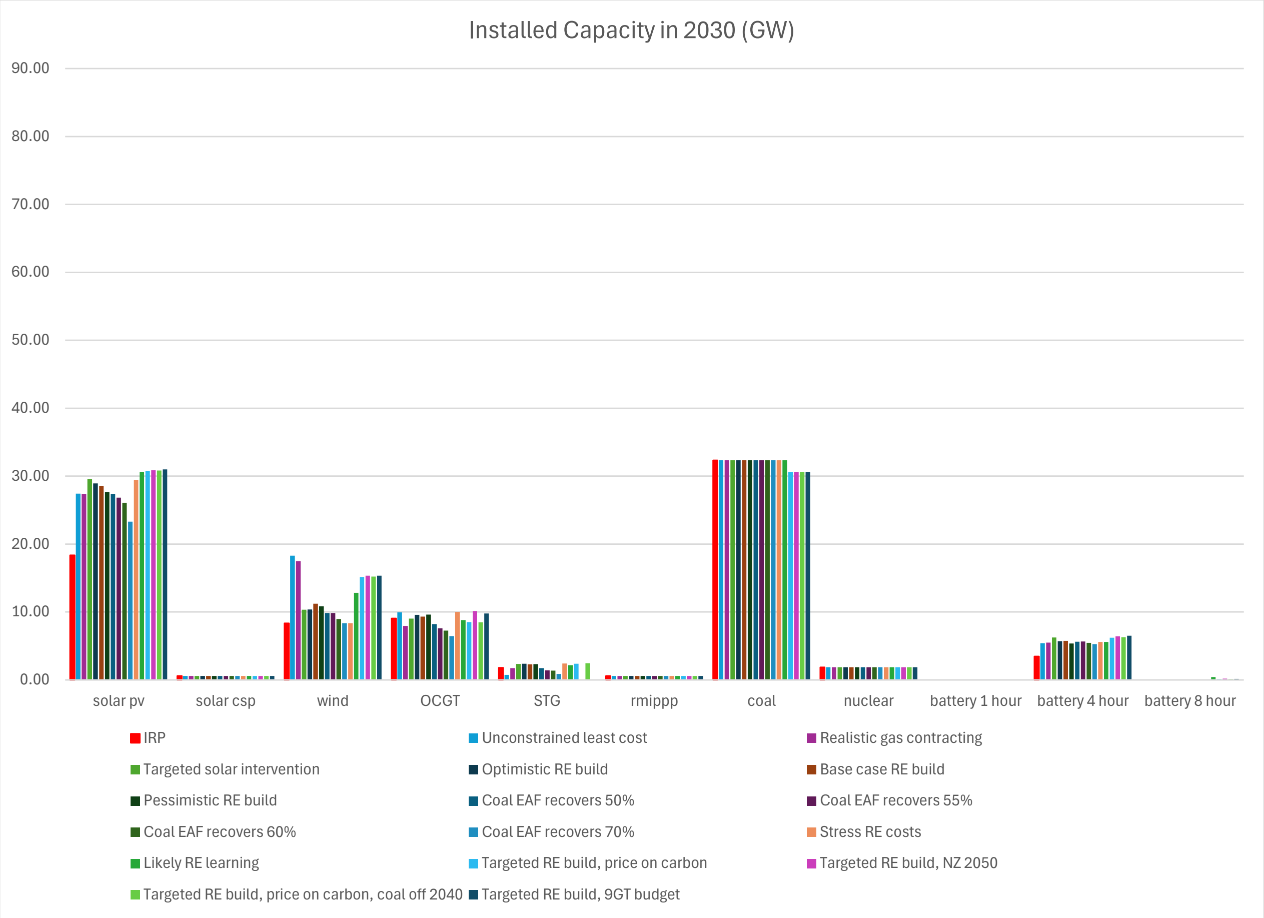
OCGT: Capital and operating costs are aligned to IRP 2023 for a 1x 9HA.02 SCGT.

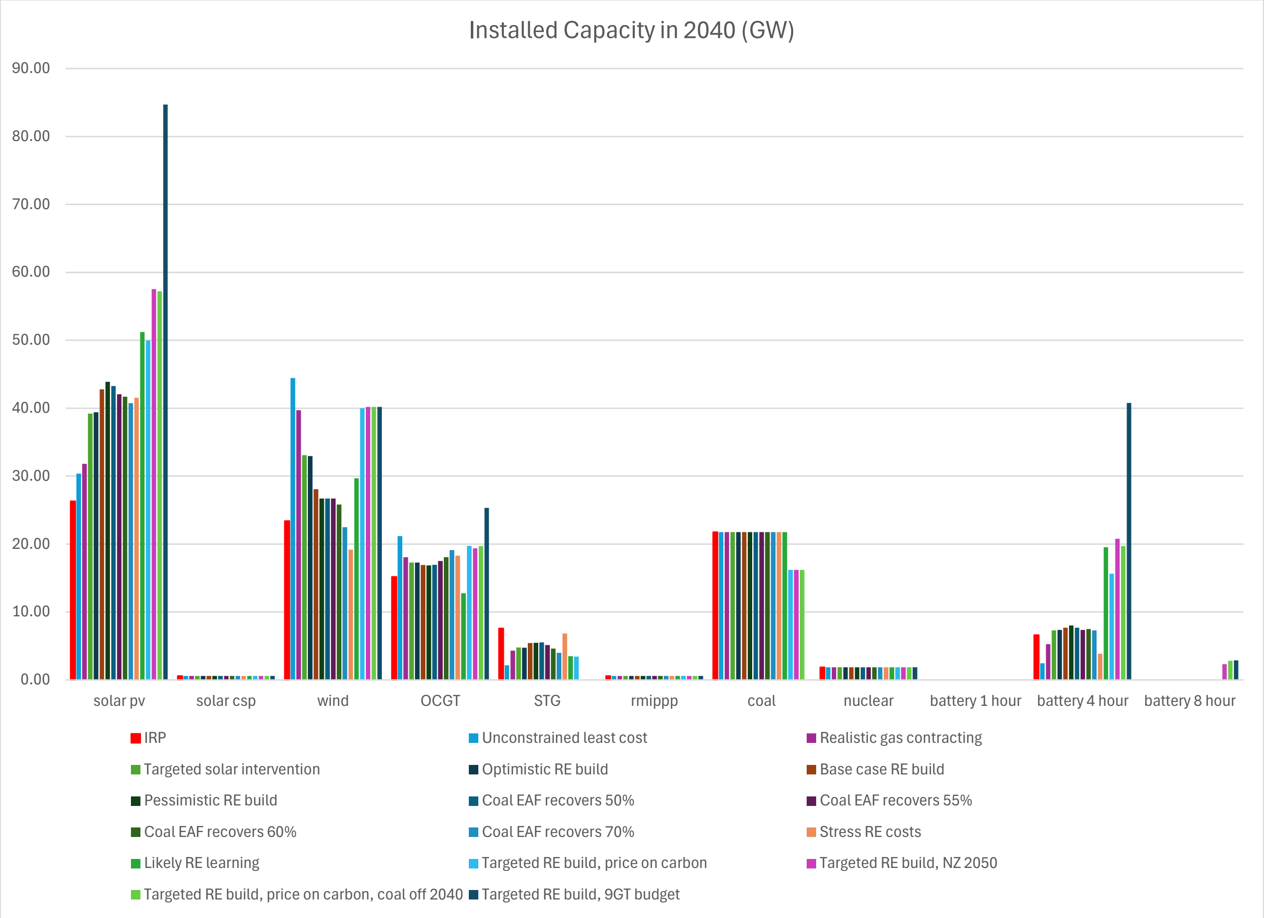
CCGT: Capital and operating costs are aligned to IRP 2023 for a 2x1 9HA.02 CCGT. Because the IRP provides the simple cycle and combined cycle costs for a 9HA.02 gas turbine, it is possible to estimate the costs of the auxiliary steam boiler and steam turbine from the IRP 2023 data.

ICE: For peaking power OCGTs/ICEs can be considered relatively interchangeable from an LCOE basis (ICE cost higher but efficiency is also higher). Currently to reduce simulation times we have focussed on an OCGT technology, but future work can consider a combination of ICEs, OCGTs and CCGTs.

Bio-energy and hydro: Although cost data is collected for these generators, we did not include these in the capacity expansion optimisation given unknowns on the capacity that can be installed and the resource availability. Typically, these capacities are small given the limited number of sites and this assumptions should not significantly affect the outcome. In future if a significant hydro or bio-energy opportunity becomes known this can be added into our model.

RESULTS SUMMARY – CAPACITY COMPARISON ACROSS SCENARIOS FOR 2030 & 2040





CONTACT US

Suite EB04, Tannery Park,
23 Belmont Road, Rondebosch, 7700
+27 21 200 5857
janet.cronje@meridianeconomics.co.za
meridianeconomics.co.za