Technical Report

Systems analysis to support increasingly ambitious CO_2 emissions scenarios in the South African electricity system

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PREPARED FOR : DR GROVE STEYN
Director
Meridian Economics
Suite EB04, Tannery Park
23 Belmont Road
Rondebosch, 7700
e-mail: grove.steyn@meridianeconomics.co.za

SUBMITTED BY : DR JARRAD WRIGHT and JOANNE CALITZ
Principal Engineer: Energy Systems
Energy Centre
Smart Places
CSIR
P O Box 395
Pretoria, 0001
Tel: +27 (0)12 842 7269
e-mail: JWright@csir.co.za and jrcalitz@csir.co.za

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Author(s):	Dr Jarrad Wright, Joanne Calitz
Reviewer(s):	Dr Clinton Carter-Brown; Crescent Mushwana; Robbie van Heerden
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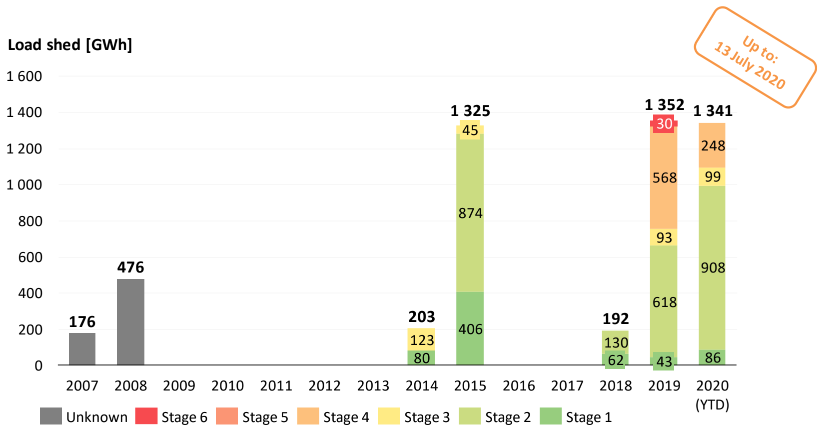
APPROVED BY:

Responsibility	**Name**	**Signature**
Project Leader	Dr Jarrad Wright	
Research Group leader (Energy Systems)	Crescent Mushwana	
Centre Manager	Dr. Clinton Carter-Brown	

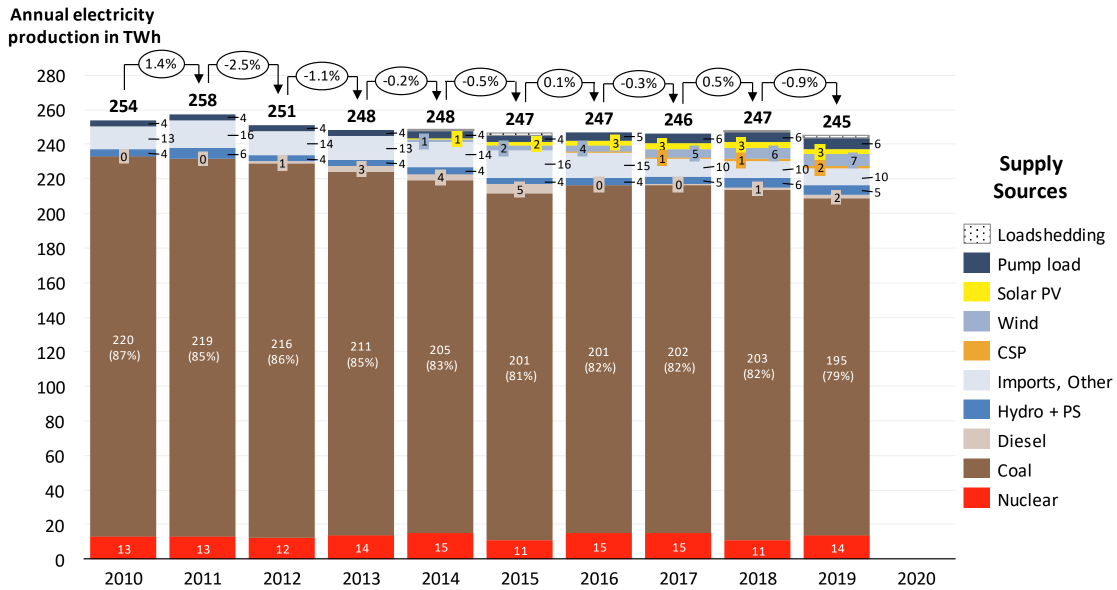
Executive Summary

The South African power system is in a crisis with urgent action required to ensure system adequacy whilst simultaneously ensuring a cleaner and more diversified energy mix

South Africa's electricity demand is currently supplied mostly by coal-fired power stations. A distinctly flat to declining demand has been experienced since at least 2010 with coal-based electricity also playing a reduced role (87% in 2010, 79% in 2019). Following historical periods of supply-demand imbalance over more than 10 years, 2019 and the first half of 2020 saw the most intensive load shedding (controlled rolling demand reduction) with ≈1.3 TWh of load shed in each of these periods. This has been driven by a combination of factors including delayed commissioning and underperformance of new-build coal generation capacity as well as degradation of existing Eskom coal fleet energy availability factor (EAF) declining from ≈94% in 2002 to 67% in 2019.



Notes: Load shedding assumed to have taken place for the full hours in which it was implemented. Practically, load shedding (and the Stage) may occassionally change/end during a particular hour; Total GWh calculated assuming Stage 1 = 1 000 MW, Stage 2 = 2 000 MW, Stage 3 = 3 000 MW, Stage 4 = 4 000 MW, Stage 5 = 5 000 MW, Stage 6 = 6 000 MW; Sources: Eskom Twitter account; Eskom se Push (mobile app); Nersa; CSIR analysis

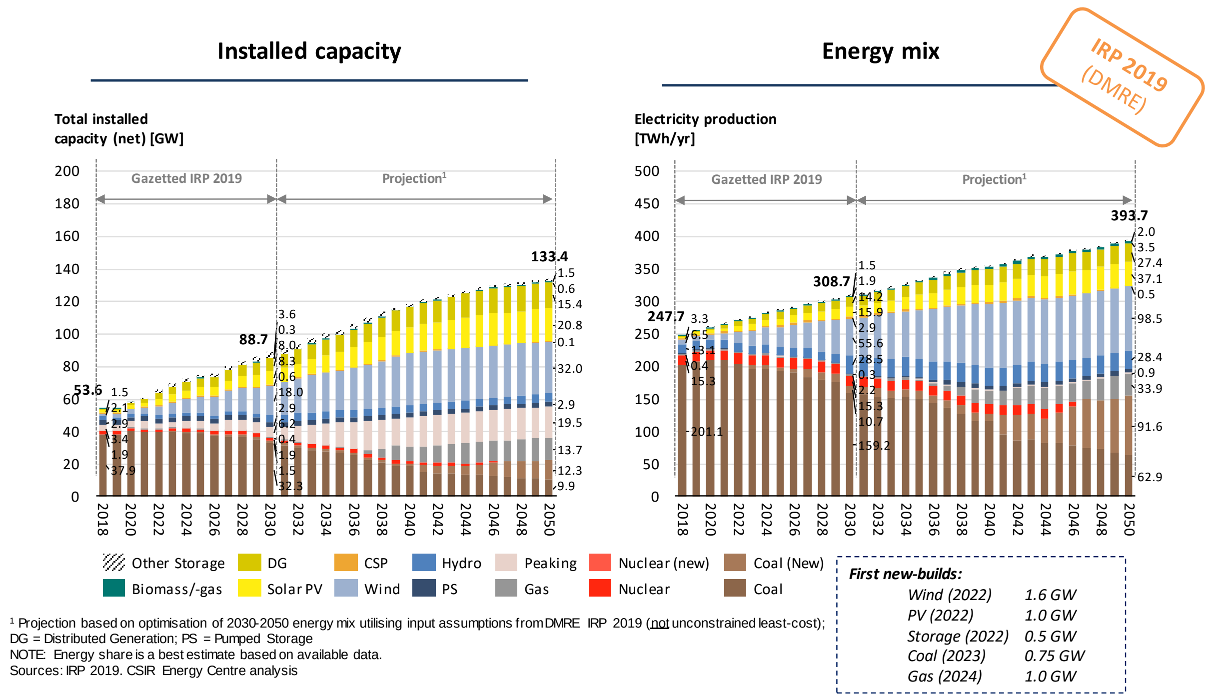


Sources: Eskom; CSIR Energy Centre analysis

Annual electricity production in South Africa (2010 to 2019) revealing flat to declining demand and reduced coal production

The IRP 2019 time horizon is expanded beyond 2030 to 2050 where it is found that a large portion of the existing coal fleet is re-built but a more diversified energy mix is expected

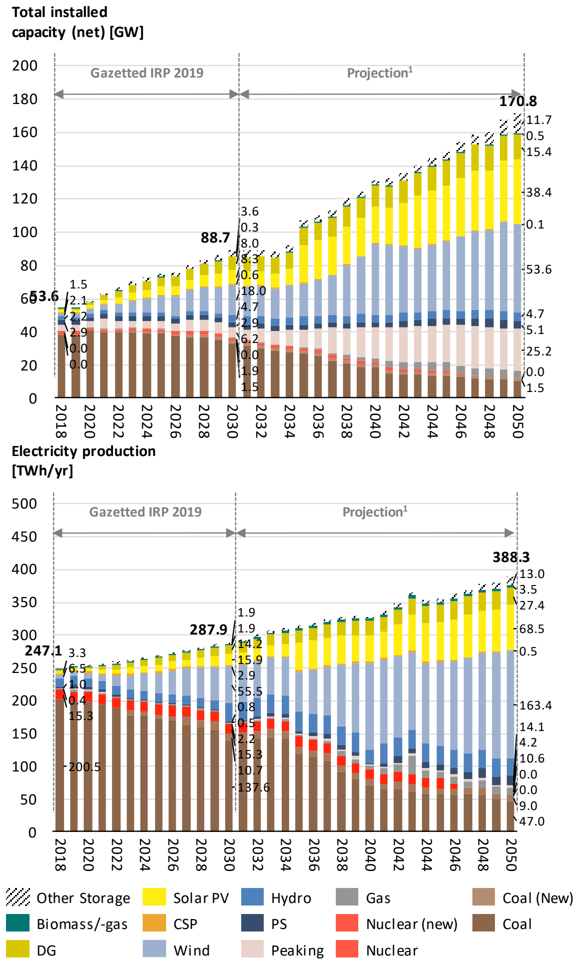
The Integrated Resource Plan (IRP) 2019 represents current policy where first new build capacity (beyond short-term emergency options) occurs in 2022 and consists of 1.6 GW of wind, 1.0 GW of solar PV and 0.5 GW of stationary storage. New coal capacity (0.75 GW) is planned for 2023 (and another 0.75 GW by 2027) as per DMRE policy adjustment process, followed by 1.0 GW of new gas capacity in 2024 (and further gas capacity from 2027 onwards). Imported hydro-based electricity of 2.5 GW from Inga is also included in 2030. After 2030, annual new-build limits on solar PV and wind combined with a non-ambitious CO_2 constraint, results in 12.3 GW of new coal capacity being built by 2050 (driving increased CO_2 emissions). Gas-fired capacity operated as peaking capacity is built pre-2030 (3.9 GW of OCGTs/GEs) whilst considerable mid-merit capacity and further peaking capacity is built thereafter (6.0 GW CCGT/GEs and 21.7 GW OCGT/GEs).



Installed capacity and energy mix for IRP 2019 (extended to 2050 by CSIR) revealing intentions for an increasingly diversified energy mix

A Reference scenario considers an updated demand forecast and EAF expectation more aligned with the latest information whilst also removing annual new-build constraints

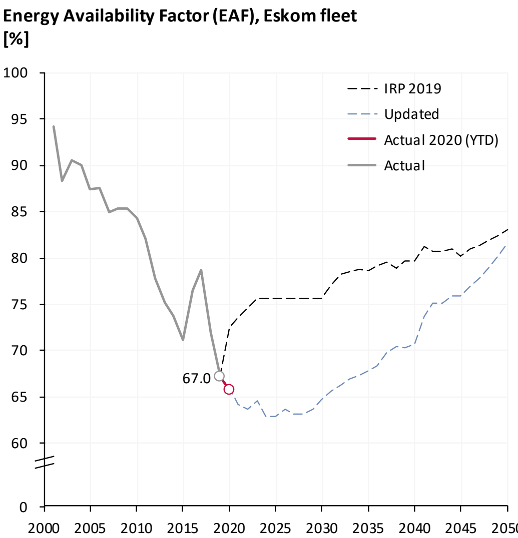
As in the IRP 2019 scenario, new build capacity was forced in as per current policy to 2030 where after the least-cost new build mix consists of solar PV, wind, storage and natural gas-fired capacity, with no further coal capacity being built. Similarly, no new-build nuclear or CSP capacity is built in this scenario. New-build storage capacity is dominated by short duration battery storage and only late in the time horizon is additional pumped storage built. Reductions of CO_2, NOx, SOx and PM emissions are observed as the existing coal fleets decommissions and is mostly replaced by renewable energy. There is also a drastic reduction in CO_2 emissions beyond 2035 as existing coal capacity decommissioning accelerates.

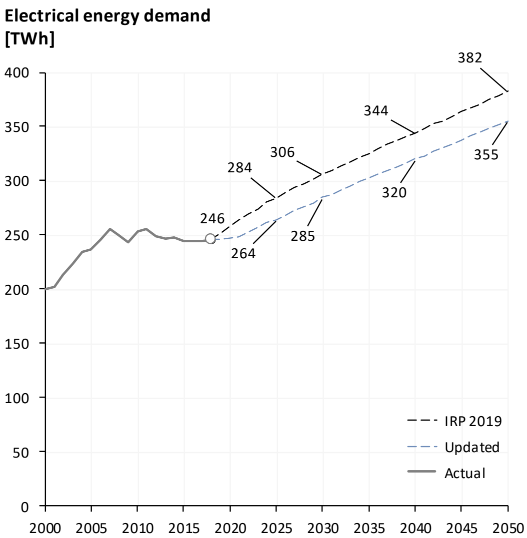


[1] Projection based on optimisation of 2030-2050 energy mix utilising CSIR input assumptions from CSIR;

DG = Distributed Generation; PS = Pumped Storage

Sources: IRP 2019. CSIR Energy Centre analysis

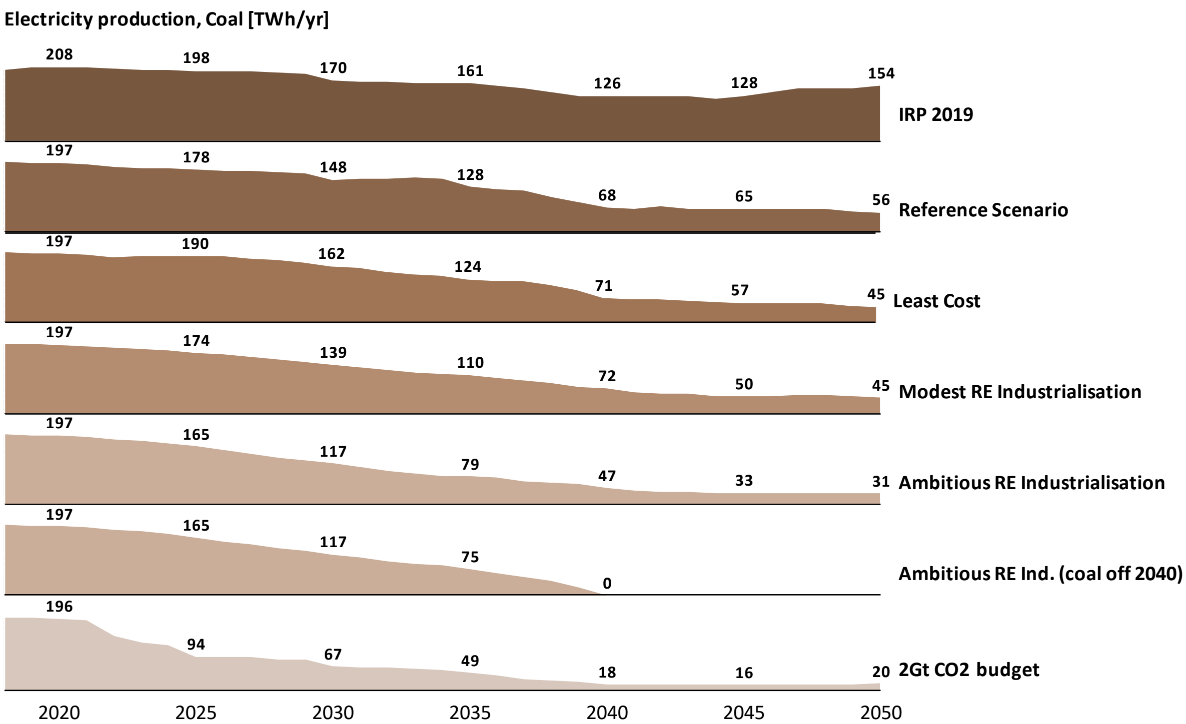




EAF and demand forecast revealing difference between IRP 2019 and Updated assumptions based on more recent information

The South African electrical energy mix is currently 81% coal but is expected to diversify as a least-cost future comprises 55% coal by 2030 and 11% coal by 2050. With lower utilization of remaining coal capacity expected, increased flexibility from this coal fleet is required in a future South African power system

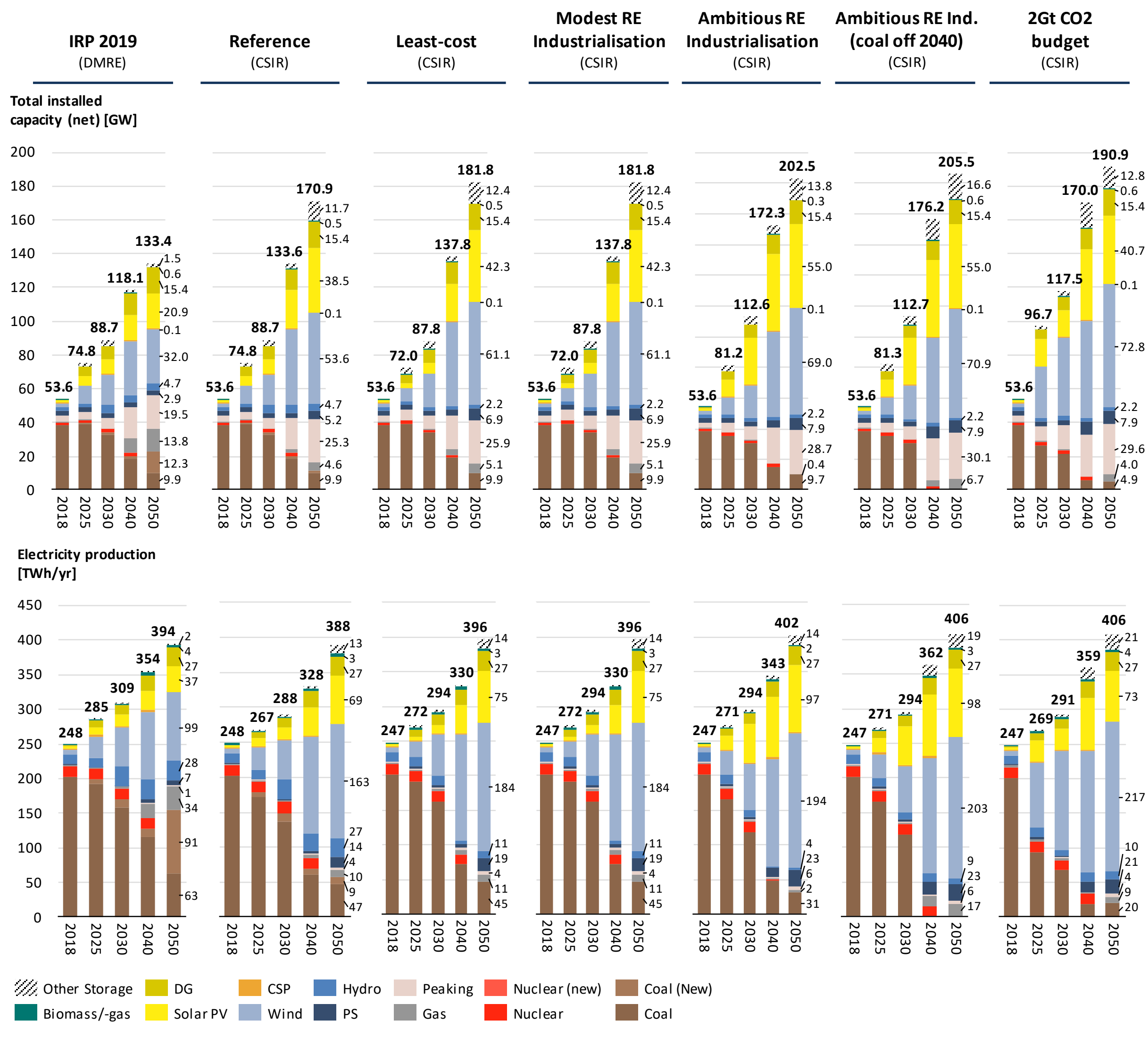
It is least-cost to shift from a coal dominated energy mix to an increasingly diversified energy mix made up of 55% coal by 2030 and 11% coal by 2050. The least-cost new build mix consists of solar PV, wind, storage and natural gas fired capacity supported by an existing fleet of generation capacity including coal, nuclear and imports. Flexibility becomes increasingly important especially in earlier years of the time horizon (pre-2030) as significant levels of coal capacity still exists and should be utilized as much as technically feasible but no more than economically optimal. Existing technical capabilities of the coal fleet is explicitly considered in this study. However, the feasibility as well as cost implications of an increasingly flexibilised coal fleet to operate at low capacity factors will need to be carefully considered as increased variable renewable energy is integrated.



South African electricity production from coal across scenarios where the role of coal reduces (in absolute terms) but remains part of the energy mix in all but one scenario (where coal is forced off by 2040) whilst increased flexibility is expected as capacity factors decline

Regardless of CO_2 ambition, renewable energy is expected to play an increasingly important role whilst other new-build low-carbon energy providers like nuclear, CSP and coal (with CCS) are not part of the least-cost energy mix

Across all scenarios, in order to meet increasingly ambitious power sector CO_2 mitigation in South Africa, wind and solar PV technologies play a dominant role. By 2030, these technologies are expected to comprise 29-64% of the energy mix depending on CO_2 ambition whilst by 2050 the energy mix would be 67-81% solar PV and wind. This means solar PV and wind installed capacity of ≈15-40 GW and ≈20-45 GW by 2030. By 2050, installed capacity of wind and solar PV is expected range from ≈30-75 GW and ≈35-70 GW respectively. Regardless of CO_2 ambition level, no new-build nuclear, coal (with/without CCS) or CSP capacity are part of least-cost optimal energy mixes.

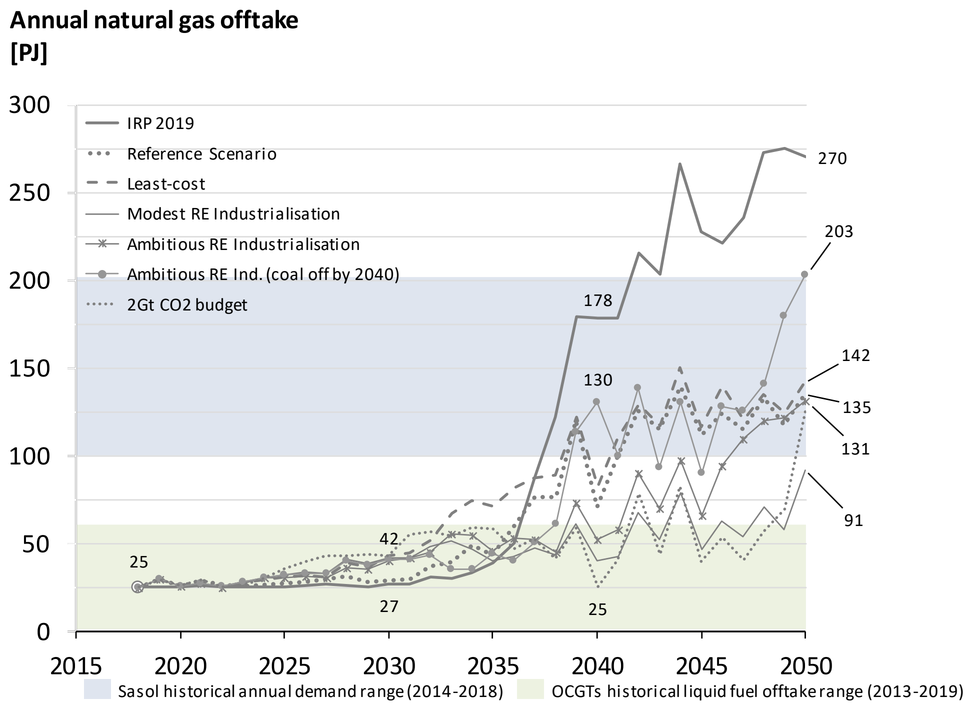


DG = Distributed Generation; PS = Pumped Storage
Sources: CSIR Energy Centre analysis

Installed capacity and production across scenarios revealing how least-cost energy mixes (even with increasing CO_2 ambitions) comprise new-build solar PV, wind, storage and natural gas capacity complemented by existing coal, nuclear, hydro, pumped storage and peaking capacity

Gas-fired generation capacity is considered as a proxy for an increased need for flexible capacity but limited energy provision means limited natural gas offtake

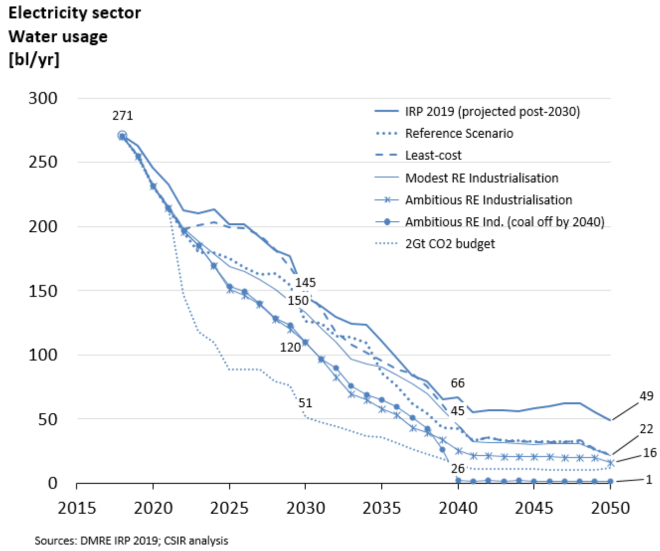
The absolute capacity of flexible natural gas-fired capacity built across scenarios is reduced relative to previous analyses undertaken by CSIR in this domain as increased levels of stationary storage is deployed. The average annual capacity factor of the gas fleet is <30% across all scenarios whilst that of peaking capacity utilizing natural gas is <5%. Thus, demand for new gas capacity is mostly driven by flexible capacity requirements (not energy). Annual natural gas offtake is expected to remain relatively low, increasing from ≈25 PJ to ≈30-40 PJ by 2030 (additional annual natural gas demand of ≈5-15 PJ). Thereafter, increased natural gas offtake of ≈40-90 PJ by 2040 (≈15-65 PJ excluding Sasol) and ≈90-140 PJ by 2050 (≈65-115 PJ excluding Sasol). An exception is when all coal capacity is decommissioned by 2040 forcing an increased annual natural gas offtake of up to ≈130 PJ by 2040 and ≈200 PJ by 2050. Similarly, in the IRP 2019 scenario, projections indicate natural gas annual offtake is expected to rise towards 180 PJ by 2040 (≈165 PJ excluding Sasol) and 270 PJ by 2050 (≈245 PJ excluding Sasol).



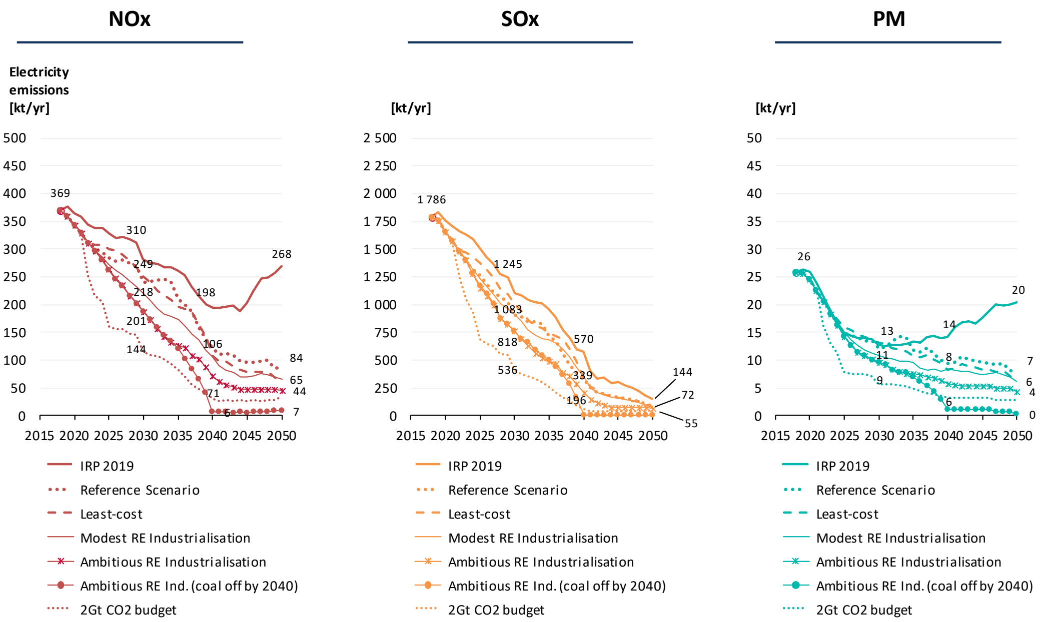
Notes: Natural Gas Price = 150 R/GJ (proxy for "expensive" natural gas); IRP 2019 not directly comparable due to higher demand forecast assumption
Sources: CSIR analysis

Natural gas offtake across scenarios showing relatively low initial natural gas offtake volumes but increasing significantly after 2035 across most scenarios towards the end of the time horizon

Water usage and emissions in the power sector are expected to continually decline with all new technologies deployed exhibiting low water and emissions intensity with resulting localised and national benefits



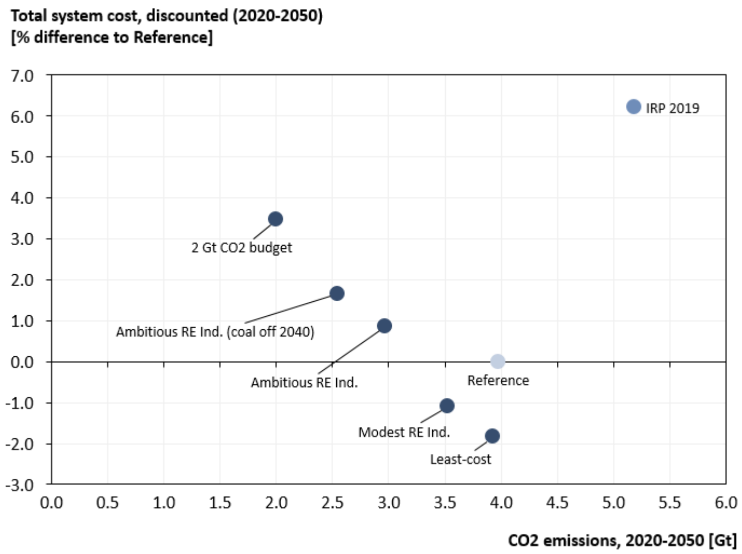
Water usage in the power sector is expected to drop significantly in all scenarios even when new-build coal capacity is built in the IRP 2019. In a scenario where all coal capacity is decommissioned by 2040, water usage becomes negligible from 2040 onwards whilst other scenarios water usage is expected to drop from ≈270 bl/yr in 2018 to ≈120-150 bl/yr by 2030, ≈25-65 bl/yr by 2040 and ≈15-50 bl/yr by 2050. With the exception of the IRP 2019 scenario where further new-build coal is built after 2030, NOx and PM emissions are expected to decline significantly as the existing coal fleet decommissions. SOx emissions decline across all scenarios as a result of any new-build coal being assumed to be fitted with flue-gas desulphurisation (FGD). The result of these findings is reduced localized air pollution and improved air quality for surrounding communities in close proximity to coal generation capacity as NOx and PM emissions are expected to decline.

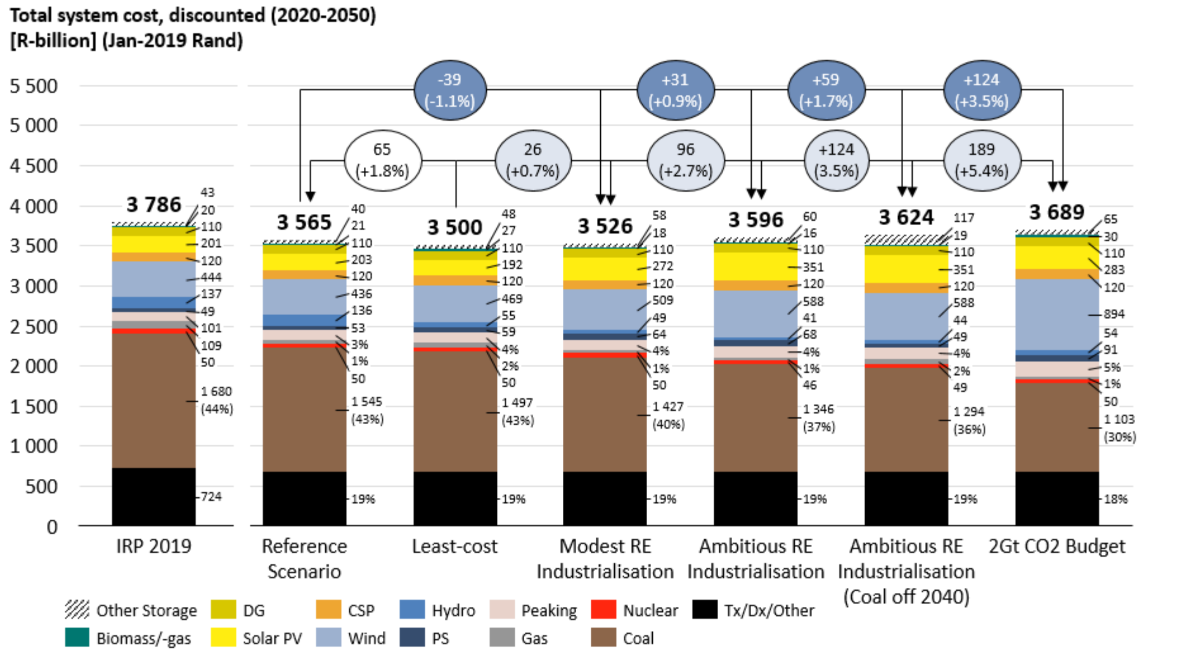


Power sector NOx, SOx and PM trajectories showing notably reduced emissions in most scenarios even as power system size grows

With increasing CO_2 ambition, system costs increase but not as much as initially expected –clearing a path for power sector decarbonization with minimal tradeoffs and substantial power sector benefits

The total discounted system cost for an Ambitious RE Industrialisation with 3.5 Gt of CO_2 emissions (for 2020-2050) is R 31-59-billion more than the Reference whilst a 2.0 Gt CO_2 budget scenario cost R 124-billion more. This represents a less than 4% increase in total system cost for substantial CO_2 mitigation gains of 0.5 Gt and 2.0 Gt of CO_2 respectively. Hence, even when imposing an earlier than optimal and smoothed renewable energy build out program or when an ambitious power sector CO_2 constraint is considered, CO_2 emissions mitigation comes at a relatively small premium. Furthermore, conservative technology costs assumed for renewable energy technologies further strengthens this finding in scenarios with increased levels of CO_2 ambition and resulting renewable energy penetration.



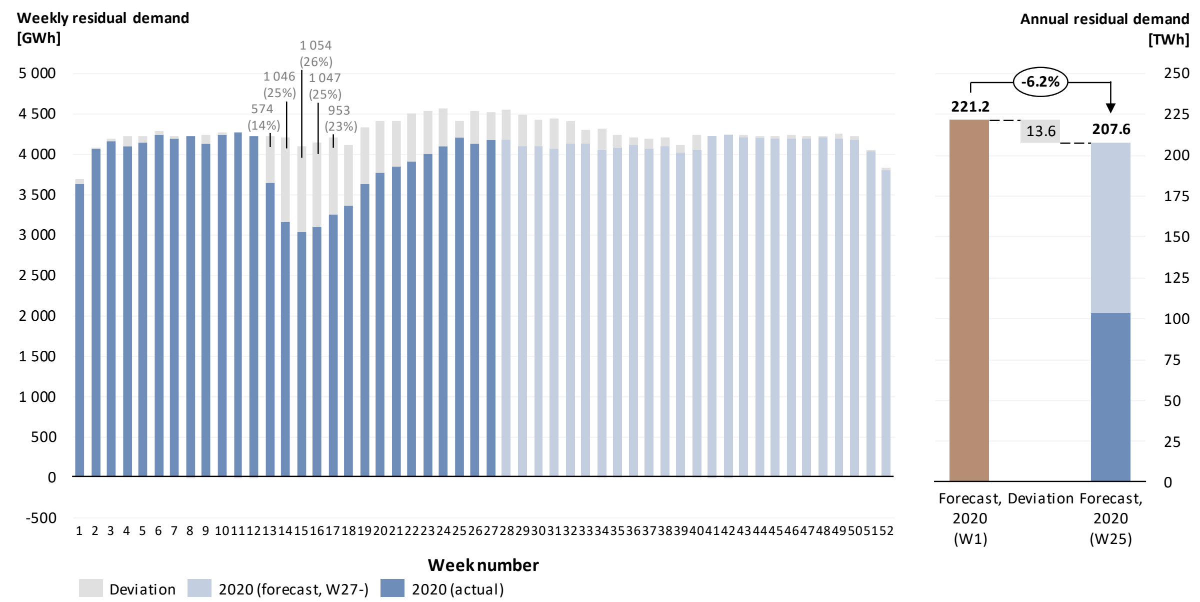


Notes: Transmission (Tx), distribution (Dx), system services (often referred to as ancillary services) and other costs not explicitly included in the PLEXOS. Modelling framework are approximated by a high level assumption of 0.20 R/kWh for all of these cost components consistently across all scenarios. Discount rate = 8.2%
Sources: CSIR Energy Centre analysis

Total system cost (discounted) for 2020-2050 revealing relatively small cost differentials as CO_2 ambition grows relative to Least-cost

The impact of the South African national lockdown to mitigate Covid-19 on the South African electricity sector has been wide-ranging but largely seen as acute reduced demand which quickly returned resulting in the return of load shedding

A novel coronavirus outbreak in Wuhan Province of China occurred in December 2019 called severe acute respiratory syndrome coronavirus 2 (SARS-CoV-2) which causes coronavirus disease 2019 (Covid-19). In response, South Africa enforced a national lockdown with a risk-adjusted strategy from 27 March 2020. One of the impacts of this is substantially reduced electricity demand. During Level 5 (5 weeks), a 23-26% weekly demand reduction occurred whilst energy demand to 7 July 2020 dropped by 10.5 TWh (-16%). For 2020, expectations are for demand to contract by 14 TWh (-6.2%). As the economy began re-opening in Level 3, electrical demand returned near immediately revealing the acute and transient effect of the lockdown on demand. This already manifested in July 2020 as Eskom commenced rotational load shedding.



Sources: Eskom; CSIR Energy Centre analysis

Weekly residual demand for 2020 highlighting the effect of the South African national lockdown (deviations during Level 5 highlighted)

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List of Abbreviations

Abbreviation	Description
ATB	Annual Technology Baseline
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
COUE	Cost of Unserved Energy
CPI	Consumer Price Index
CSIR	Council for Scientific and Industrial Research
CSP	Concentrated Solar Power
DG	Distributed Generation
DMRE	Department of Mineral Resources and Energy
DRC	Democratic Republic of Congo
Dx	Distribution Network
EG	Embedded Generation
EOCK	Economic Opportunity Cost of Capital
ESP	Electrostatic Precipitators
FBC	Fluidized Bed Combustion
FFP	Fabric Filter Plant
FGD	Flue-gas Desulfurisation
FOM	Fixed Operations and Maintenance
GDP	Gross Domestic Product
GE	Gas Engine
GHG	Greenhouse Gas
GW	Gigawatt (1 000 000 000 W)
GWh	Gigawatt hour (1 000 000 000 Wh)
ICE	Internal Combustion Engine
IGCC	Integrated Coal Gasification Combined Cycle
INDC	Intended Nationally Determined Contribution
IRP	Integrated Resource Plan
LCOE	Levelized Cost of Electricity
LNB	Low NOx Burners
LNG	Liquified Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability

Abbreviation	Description
MES	Minimum Emission Standard
MSL	Minimum Stable Level
NEMAQA	National Environmental Management: Air Quality Act
NERSA	National Energy Regulator of South Africa
NOx	Nitrogen Oxides: Nitrogen dioxide (NO2) and Nitrogen oxide (NO)
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
OCGT	Open Cycle Gas Turbine
PF	Pulverized Fuel
PM	Particulate Matter
PPD	Peak-Plateau-Decline
PV	Photovoltaic
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
RFI	Request for Information
RSA	Republic of South Africa
SOx	Sulphur related emission compounds (i.e. sulphur dioxide, SO_2)
SSEG	Small Scale Embedded Generation
Tx	Transmission Network
UNFCCC	United Nations Framework Convention on Climate Change
VOM	Variable Operations and Maintenance
WASA	Wind Atlas of South Africa
YTD	Year to date

1 Background and project overview

1.1 Background – current power sector landscape

South Africa's electricity demand is currently supplied mostly by coal-fired power stations (79% in 2019) which are primarily owned and operated by Eskom, the national power utility. Eskom supplies over 95% of the country's total electricity demand, with the remaining demand being met by municipalities, imports and independent power producers (IPPs). Figure 1 shows the annual electricity production in South Africa from 2010 to 2019 revealing a distinctly flat to declining annual demand with a similar trend on coal-based electricity production reducing from 220 TWh in 2010 to 195 TWh in 2019 whilst coal capacity increased from 34.3 GW in 2010 to 36.5 GW in 2019.

The South African power system has seen sporadic periods of supply-demand imbalance over more than 10 years now. This is demonstrated in Figure 2 showing the events of load shedding1 experienced for the period of 2007-2020 (YTD), with the worst events seen in 2019 and 2020 (up to June) where ≈1.3 TWh and ≈1.2 TWh of load was shed respectively. All of the load shed in the first half of 2020 was actually shed within the first 12 weeks of the year whereafter an extended economic lockdown and risk-adjusted strategy was implemented in response to a growing Covid-19 pandemic [1], [2]. A brief analysis of the effect of Covid-19 is further elaborated on in section 4.

Figure 3 and Figure 4 show the hourly load shedding distribution (by load shedding stage) for 2019 and 2020 (year to date) respectively. This has been driven by a combination of factors including delayed commissioning and underperformance of new-build coal generation capacity at Medupi and Kusile as well as the degradation of the existing Eskom coal fleet energy availability factor (EAF). The historical EAF as seen in Figure 5 reveals the declining EAF trend over the period of 2016-2020 (YTD). The current year-to-date (YTD) average EAF of 65.7% against a planned 72.5% EAF (from IRP 2019) [3] and 70% for FY 2020/21 (from Eskom) [4] reveal the notably lower than planned performance. On 10 July 2020, Stage 2 load shedding was implemented [5], revealing the underlying reality of an inadequate power system that still requires urgent attention.

Various draft and final iterations of the Integrated Resource Plan (IRP)[2] from 2010-2020 are summarised in Figure 6 across important dimensions including the energy mix, demand, emissions (CO_2), nuclear, imports, coal fleet performance, new-build coal, new technologies, security

[1] Load shedding is initiated by Eskom and is done countrywide as a controlled option to respond to unplanned events to protect the electricity power system from a total blackout.
[2] The IRP is an electricity infrastructure development plan conducted by the DMRE.

of supply and network requirements. One of the clear outcomes of updated policy positioning on the energy mix and of relevance for this study, is the continually declining role of coal for power generation as part of a diversified energy mix. Simultaneously, there has not been a particular increased focus on limiting long-term power sector CO_2 emissions as only a shift from a peak CO_2 emissions constraint (275 Mt/year) in the IRP 2010 became a moderate Peak-Plateau-Decline (PPD) trajectory for CO_2 emissions in the power sector (with 275 Mt/year until 2037 and consistent decline to 210 Mt/year thereafter by 2050).

The most recent iteration of the IRP is a promulgated version - the IRP 2019 as published in October 2019 by the Department of Mineral Resources and Energy (DMRE) [3]. This is the newly established policy position on the national power sector energy mix to 2030. The key decisions included in the IRP 2019 are listed in Figure 7 where particular decisions are highlighted in blue when supported by the evidence-base whilst grey text highlights either a notable lack of evidence-base or are contradictory to the available evidence-base.

1.2 Objective

To explore additional cumulatively more ambitious CO_2 emissions abatement scenarios in the South African power system over the long-term (for the period 2020-2050).

Thus, the speed of reducing power sector CO_2 emissions in the power sector is explored from a systems perspective to assess the effects on the energy mix and associated technologies, resulting CO_2 emissions, other emissions (PM, SOx, NOx) and total system costs for a range of increasingly ambitious CO_2 scenarios.

This systems analysis is intended to inform a detailed techno-financial modelling exercise to assess the viability of clean climate funding to assist ongoing and systemic financial challenges at Eskom.

1.3 Document overview

This report is structured as follows:

- Section 1: is this section;
- Section 2: Power system analysis;
- Section 3: Scenario results;
- Section 4: Brief assessment of Covid-19 impact;
- Section 5: Summary and conclusions

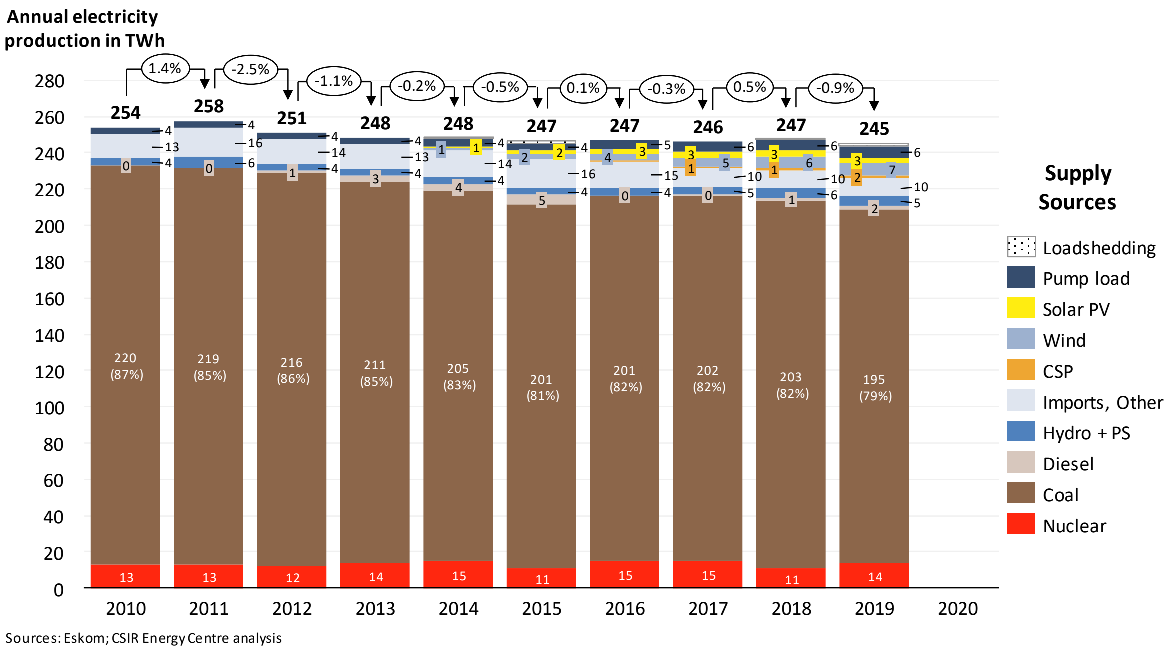


Figure 1. Annual electricity production in South Africa (2010 to 2019) supplied by a combination of Eskom-owned generators, electricity imports and energy produced by IPPs

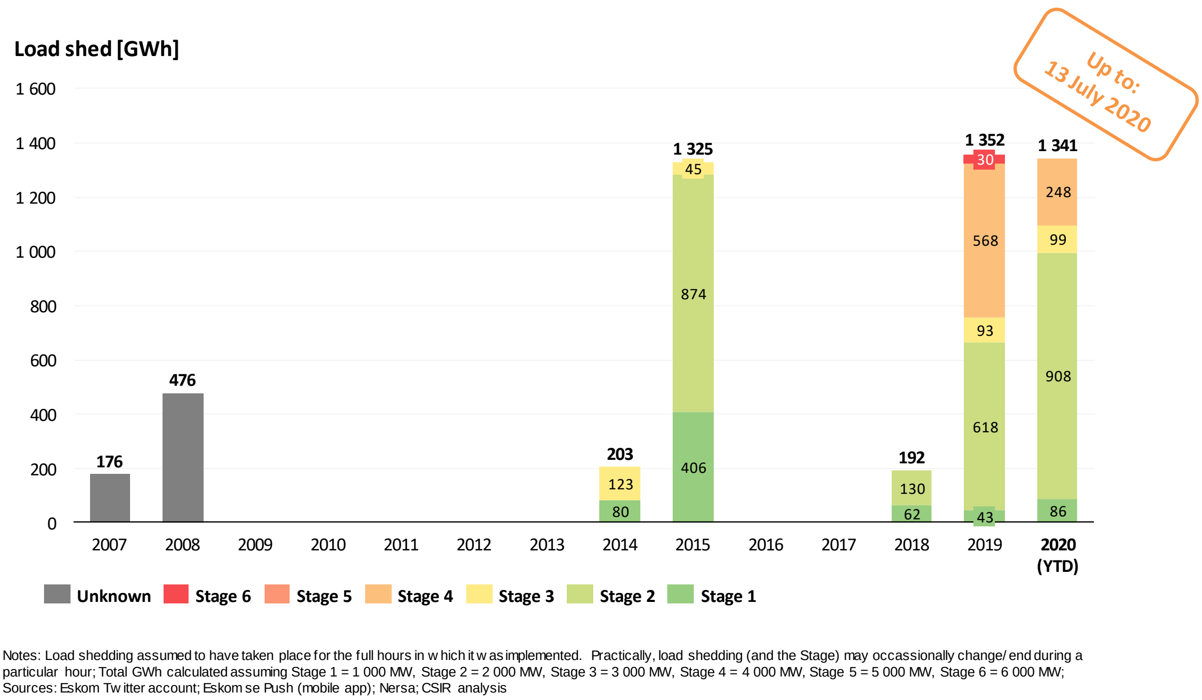
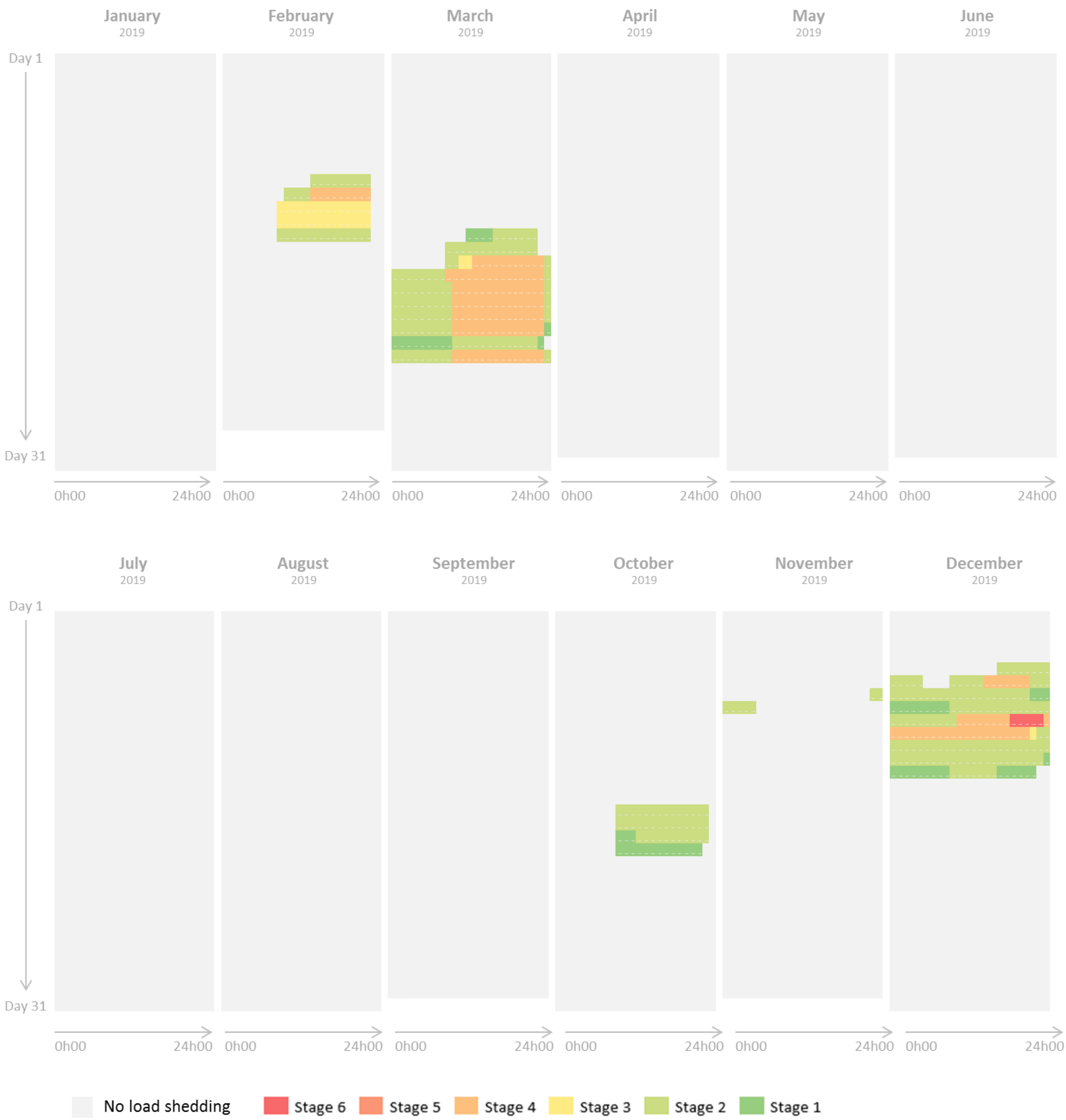
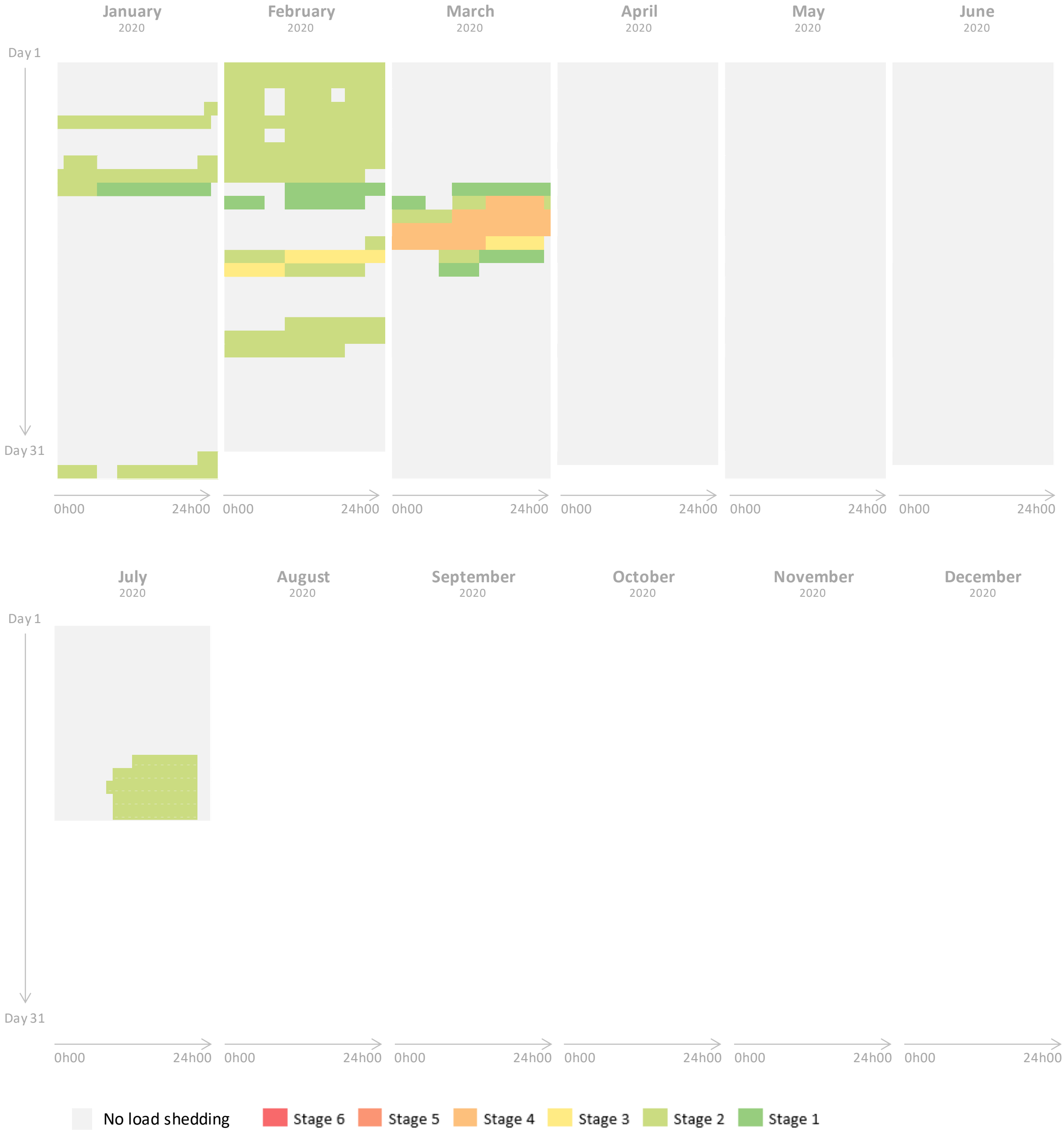


Figure 2. Annual load shedding in GWh in South Africa from 2007 to 2020 (YTD – 13 July 2020).



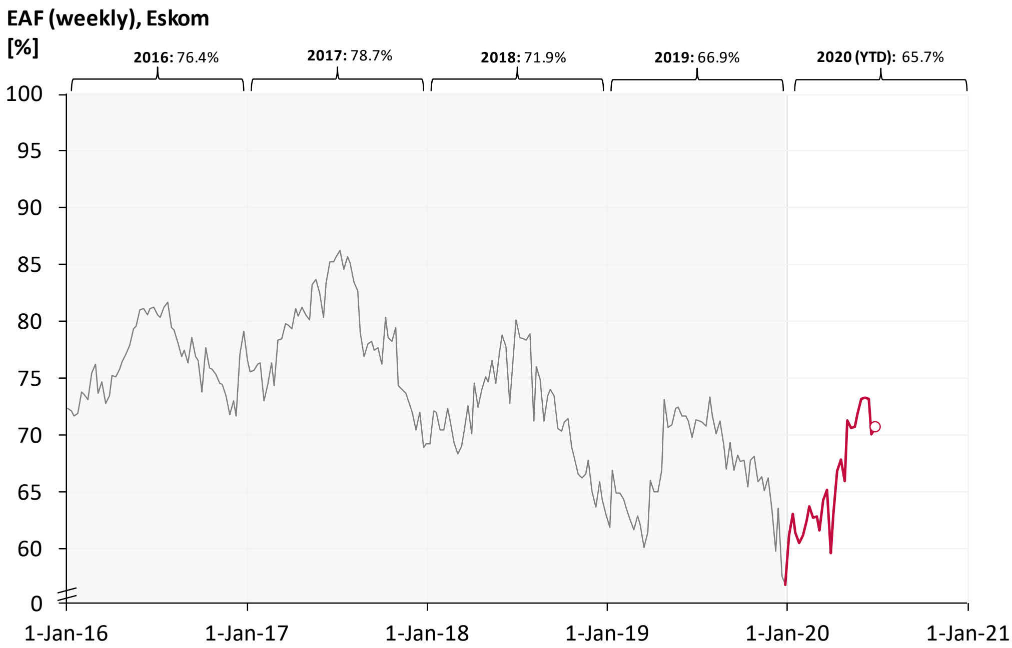
Notes: Load shedding assumed to have taken place for the full hours in which it was implemented. Practically, load shedding (and the Stage) may occassionally change/ end during a particular hour; Total GWh calculated assuming Stage 1 = 1 000 MW, Stage 2 = 2 000 MW, Stage 3 = 3 000 MW, Stage 4 = 4 000 MW, Stage 5 = 5 000 MW, Stage 6 = 6 000 MW
Sources: Eskom Twitter account; Eskom se Push (mobile app); CSIR analysis

Figure 3. Hourly load shedding (2019 focus), depicting how constrained the power system is across all hours of the day (signaling an energy shortage, not just a capacity shortage)



Notes: Load shedding assumed to have taken place for the full hours in which it was implemented. Practically, load shedding (and the Stage) may occassionally change/end during a particular hour; Total GWh calculated assuming Stage 1 = 1 000 MW, Stage 2 = 2 000 MW, Stage 3 = 3 000 MW, Stage 4 = 4 000 MW, Stage 5 = 5 000 MW, Stage 6 = 6 000 MW
Sources: Eskom Twitter account; Eskom se Push (mobile app); CSIR analysis

Figure 4. Hourly load shedding 2020 YTD focus), showing a very constrained power system prior to and after the national Lockdown (March-May)



NOTES: EAF - Energy Availability Factor
Sources: Eskom; CSIR Energy Centre analysis

Figure 5. Eskom thermal fleet historical weekly energy availability factor (EAF) 2016-2020 (YTD), a seasonal pattern is evident where planned maintenance is reduced during winter months, increasing the EAF.

	IRP 2010-2030 (Promulgated 2011) t: 2010-2030	IRP Update 2013 (Not promulgated) t: 2013-2050	Draft IRP 2016 (Public consultation) t: 2016-2050	Draft IRP 2018 (Aug. 2018) t: 2016-2030	IRP 2019 (Gazetted Oct. 2019) t: 2018-2030
Expected energy mix	Scenario-based; **Big:** Coal, nuclear **Medium:** VRE, gas **Small:** imports (hydro)	Decision trees; **Big:** Coal, nuclear **Medium:** VRE, gas, CSP **Small:** Imports (hydro, coal), others	Scenario-based **Big:** Coal **Medium:** Nuclear, Gas, VRE **Small:** Imports (hydro), others	Scenario-based **Big:** Coal, VRE **Medium:** Gas **Small:** Nuclear, DG/EG imports (hydro), others	Scenario-based; **Big:** Coal, VRE **Medium:** Gas, DG/EG **Small:** Nuclear, Imports (hydro), Storage, others
Demand	454 TWh (2030)	409 TWh (2030) 522 TWh (2050)	350 TWh (2030) 527 TWh (2050)	313 TWh (2030) 392 TWh (2050)	307 TWh (2030) 382 TWh (2050)
Emissions (CO_2-eq)	Peak only, EM1 (275 Mt from 2025)	PPD (Moderate)	PPD (Moderate)	PPD (Moderate)	PPD (Moderate)
Nuclear options	Commit to 9.6 GW	Delay option (2025-2035)	No new nuclear pre-2030; 1st units (2037)	No new nuclear pre-2030; (pace/scale/affordability) 1st units (2036-2037)	No new nuclear pre-2030; (pace/scale/affordability) 2.5 GW (≥2030)
Import options	Coal, hydro/PS, gas (fuel)	Coal, hydro/PS, gas (fuel)	Hydro, gas (fuel)	Hydro, gas (fuel)	Hydro, gas (fuel)
Coal fleet performance	>85% EAF; 50 year decom.	~80% EAF; LifeEx (10 yrs)	72-80% EAF; 50 year decom. MES delay (2020/25)	72-80%; 50 year decom. MES delay (2020/25)	67-76%; 50 year decom. MES delay (2020/25)
New-build coal	1st units forced earlier 1.0 GW (2014) 6.3 GW (2030)	Displaced by LifeEx (10 yrs) 1.0 GW (2025) <3.0 GW by 2030	1st 1.5 GW (2028) 4.3 GW (2030)	0.5 GW (2023) 1.0 GW (2030)	0.75 GW (2023) 1.5 GW (2030)
New technologies[1]	Uncertain VRE cost/perf. CSP (marginal); Annual constr.: 0.3-1.0 GW/yr (PV) 1.6 GW/yr (wind)	Uncertain VRE cost/perf. CSP (notable); Annual constr.: 1.0 GW/yr (PV) 1.6 GW/yr (wind)	VRE cost/perf. proven CSP (minimal); Battery/CAES (option); Annual constr.: 1.0 GW/yr (PV) 1.6 GW/yr (wind)	VRE cost/perf. proven CSP (minimal); Batteries (option); Annual constr.: 1.0 GW/yr (PV) 1.6 GW/yr (wind)	VRE cost/perf. proven CSP (minimal); Batteries (notable); Annual constr.: 1.0 GW/yr (PV) 1.6 GW/yr (wind)
Security of supply	LT (reserve margin); ST (hourly dispatch); Immediate ST need; Research: Fuel supply, base-load, backup, high VRE	LT (reserve margin); ST (hourly dispatch); Research: Fuel supply, base-load, backup, high VRE	Assumed similar Research: None highlighted	Assumed similar Research: Gas supply, high VRE, just transition	Assumed similar; Immediate ST need; Research: Gas supply, high VRE, just transition
Network requirements[2]	Not considered; Tx/Dx research need	Not a concern (Tx power corridors) Dx networks research need (DG/EG)	None	Explicit Tx needs costed (per tech.)	Explicit Tx needs costed (per tech.)

Figure 6. Summary of South Africa's IRP's from 2010-2019 and the key planning assumptions associated with each

Decision 1

Undertake a power purchase programme to assist with the acquisition of capacity needed to supplement Eskom's declining plant performance and to reduce the extensive utilisation of diesel peaking generators in the immediate to medium term. Lead-time is therefore key.

Decision 2

Koeberg power plant design life must be extended by another 20 years by undertaking the necessary technical and regulatory work.

Decision 3

Support Eskom to comply with MES over time, taking into account the energy security imperative and the risk of adverse economic impact.

Decision 4

For coherent policy development in support of the development of a just transition plan, consolidate into a single team the various initiatives being undertaken on just transition.

Decision 5

Retain the current annual build limits on renewables (wind and PV) pending the finalisation of a just transition plan.

Decision 6

South Africa should not sterilise the development of its coal resources for purposes of power generation, instead all new coal power projects must be based on high efficiency, low emission technologies and other cleaner coal technologies.

Decision 7

To support the development of gas infrastructure and in addition to the new gas to power capacity in Table 5*, convert existing diesel-fired power plants (Peakers) to gas.

Decision 8

Commence preparations for a nuclear build programme to the extent of 2500 MW at a pace and scale that the country can afford because it is a no-regret option in the long term.

Decision 9

In support of regional electricity interconnection including hydropower and gas, South Africa will participate in strategic power projects that enable the development of cross- border infrastructure needed for the regional energy trading.

NOTE: Decisions in grey lack evidence-base or are contradictory to the available evidence-base; MES – Minimum Emission Standards; Table 5 in IRP 2019 document.
Sources: IRP 2019; CSIR Energy Centre analysis

Figure 7. Summary of decisions highlighted in IRP 2019 [6]

2 Power system analysis

2.1 Approach

2.1.1 Electricity modelling framework

A typical energy planning framework was applied in this study (Figure 8). A range of input assumptions informed by various data sources (as will be highlighted in section 2.3) are provided to a modelling framework (PLEXOS®) [7] applying a long-term generation expansion planning optimisation resulting in scenario specific outputs across important dimensions.

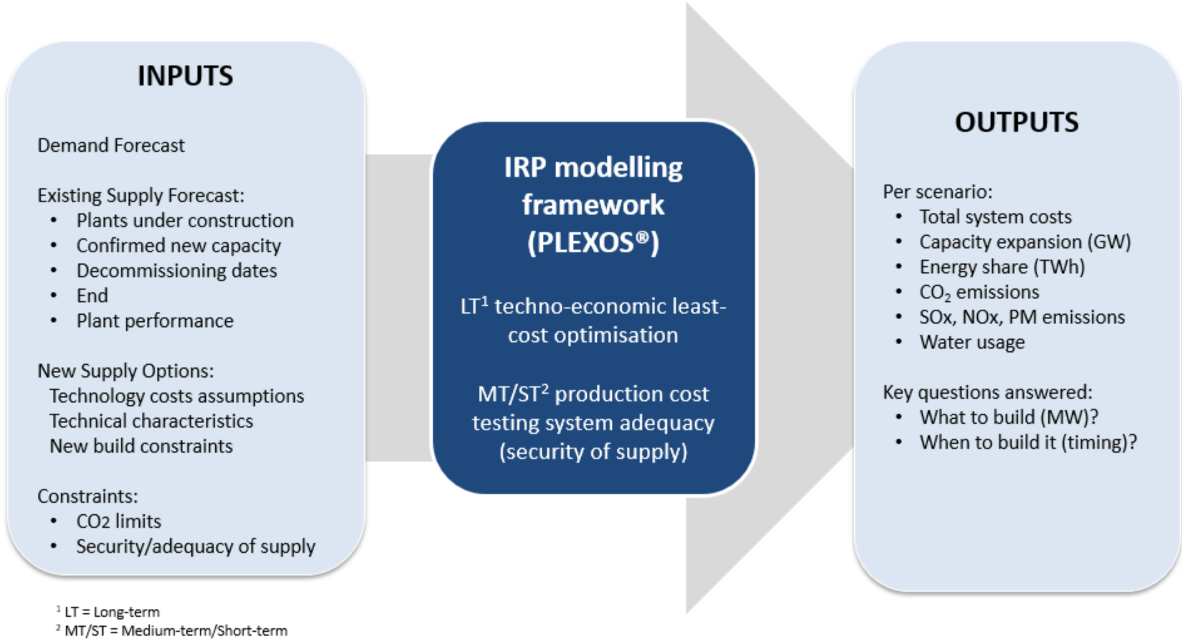


Figure 8. Methodology applied when undertaking long-term energy planning

The temporal resolution of the optimisation is hourly with the study horizon being 2018-2050. The model co-optimises existing supply-side options (such as the Eskom generation fleet) and new-build investments over the planning horizon with the objective function of least-cost (subject to pre-defined boundary conditions). The definition of input assumptions and boundary conditions define a range of scenarios and sensitivities which can then be compared against each other (as discussed in section 2.2).

The outputs from the generation capacity expansion planning include the capacity and timing of new power generators as well as how these generators are expected to operate (energy production). Figure 9 illustrates the least-cost capacity expansion planning optimisation problem. The least-cost plan occurs at the level of investment which minimises investment cost and production cost of both existing and new investments. Investment costs include new capital costs whilst production costs include all costs associated with operating existing and new generation investments.

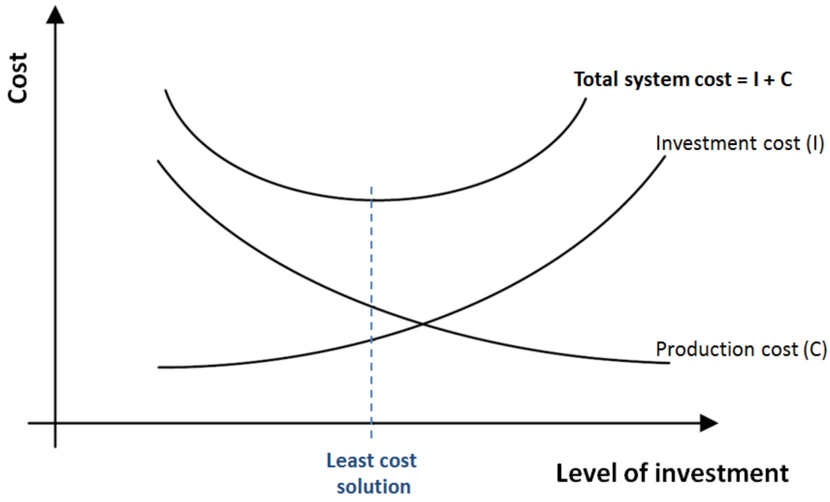


Figure 9. Illustration of the capacity expansion planning optimization [8] where the least cost solution is sought

2.1.2 Total system costs and average tariff trajectory

Power generation cost characteristics can be grouped into two broad categories, namely capacity driven costs (fixed costs) and energy-driven costs (variable costs) as shown in Figure 10. These costs are modelled explicitly within the modelling framework used in this study (PLEXOS®). The modelling framework considers these costs combined with existing and new capacity characteristics relative to system demand to determine a least-cost expansion plan. It is important to note that the utilisation of a generator (if it is chosen as part of the least-cost energy mix) is an output of the modelling framework and is not provided to the model as an input.

The fixed and variable costs of any generator form part of the calculation of the well-known Levelised Cost of Electricity (LCOE) and is used as a valuable metric (typically to compare the relative costs of different power generation technologies). Capacity-driven costs consist of the capital investment cost ("capex") associated with building a power generator and Fixed Operations and Maintenance (FOM) costs for operating a power generator. The energy driven costs consist of Variable Operations and Maintenance (VOM) and fuel costs (these are a function of utilisation). Start costs have also been explicitly included in this analysis (not shown in Figure 10).

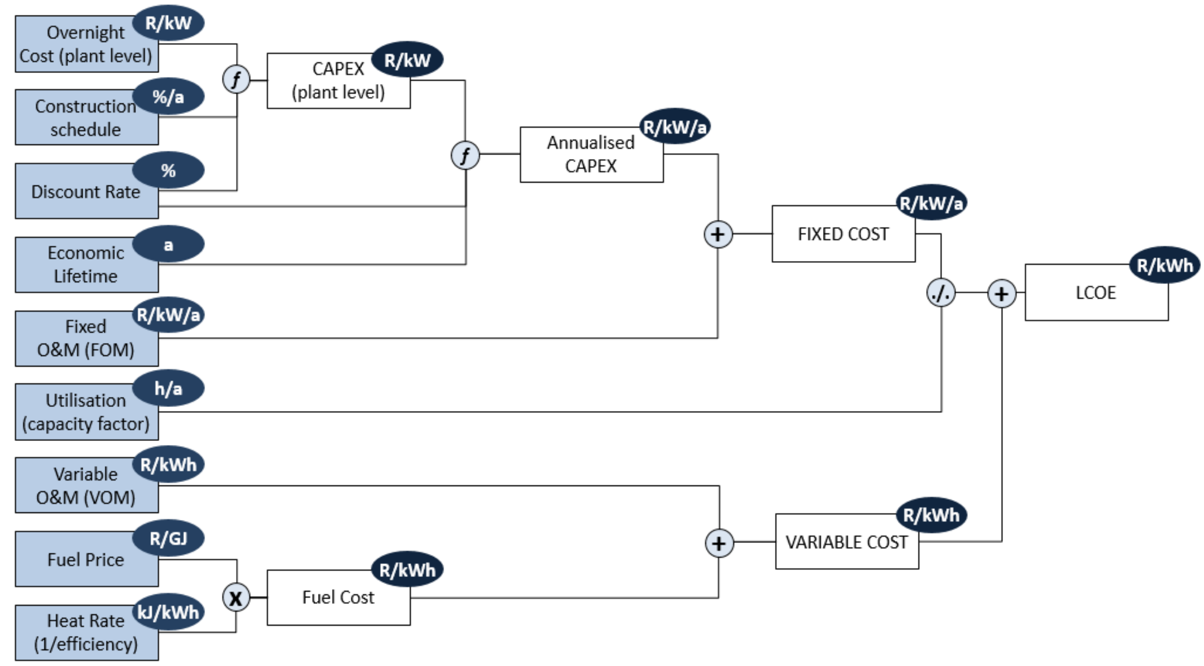


Figure 10. Conceptual breakdown of generator cost drivers which inform the LCOE of a particular technology.

As shown stylistically in Figure 11, total system cost is made up of several components. The cost for each scenario is inclusive of fixed costs (power generator capital investment and O&M), variable costs (fuel and O&M) and start/stop costs for all existing and new build power generators.

The capital and fixed operating costs for emission abatements at existing coal-fired stations are also included in the total system cost (see section 2.3). These costs are forced to be incurred in the IRP 2019 scenario as a result of the 50-year decommissioning life included whilst all other scenarios in this study assume endogenous coal fleet decommissioning. Thus, in all other scenarios considered, these costs could be avoided if optimal to do so. The sum of all existing and new generator costs outlined above makes up the total cost of power generation.

Transmission network costs (Tx), distribution network costs (Dx), system services (excluding reserves) and other minor costs are not explicitly included in the modelling framework. As a result, a high-level assumption of 0.20 R/kWh for all of these cost components is made consistently across all scenarios in order to enable a consistent relative comparison. The immediate network costs to integrate new generation capacity (shallow network costs) are implicitly included for new-build generation capacity.

The average tariff trajectory is the total system cost described above divided into customer demand in each year for all scenarios. It is appreciated that the absolute costs that result from scenarios run in this analysis may differ to that of those run by the DMRE as part of the IRP 2019. However, CSIR have utilised all information available in the IRP 2019 [3] but otherwise made generally accepted assumptions from public domain information as described in section 2.3. It is important to note that the comparisons made between scenarios are all relative comparisons to each other and thus consistency in the relative comparisons is made possible.

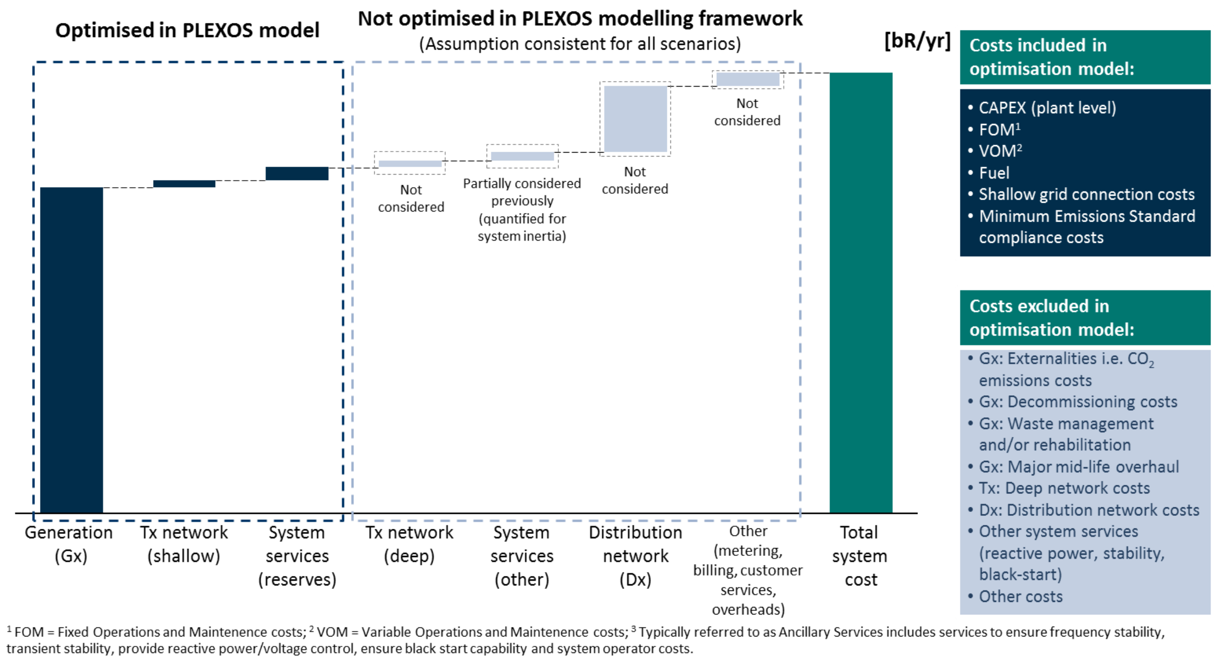


Figure 11. Modelling framework inclusions/exclusions and total system cost reporting approach

2.1.3 Model exclusions

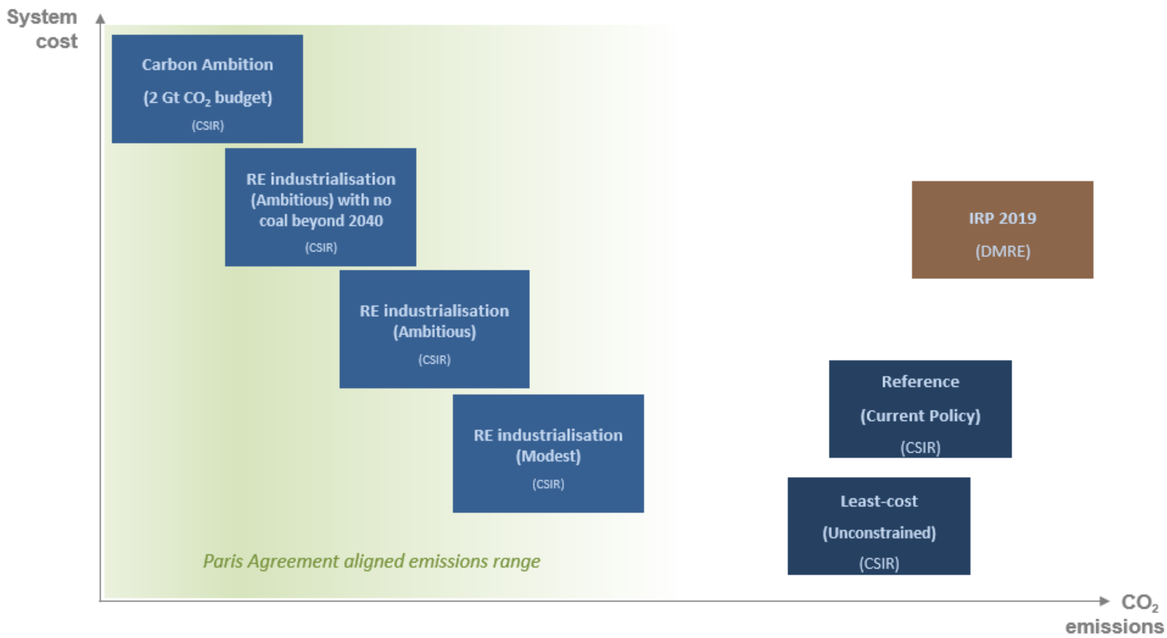
The modelling framework considers all primary cost-drivers directly relevant within the electricity sector (as shown in Figure 11). It is important to note the following exclusions from the modelling framework optimisation (also excluded from IRP 2019):

- Power generation technologies externality costs (CO_2 emissions);
- End of life decommissioning costs for any technology;
- Waste management and/or site rehabilitation;
- Mid-life generator major maintenance and overhauls for any technology;
- Network infrastructure requirements (deep transmission costs and all distribution costs);
- System services (stability, reactive power and voltage control, black-start requirements); and
- Other costs (including metering, billing and customer services)

2.2 Scenarios

Scenarios considered are shown graphically in Figure 12 with total system costs relative to total CO_2 emissions over the study period (2020-2050). The focus on system cost relative to CO_2 emissions is in order to demonstrate the relative differences in total system costs as a range of different CO_2 emissions pathways are explored. The range of power sector CO_2 emissions that would align with the United Nations Framework Convention on Climate Change (UNFCCC) Paris Agreement (which South Africa is a signatory) is also shown in Figure 12 for information [9], [10].

Further detail to describe the scenarios explored across key parameters is provided in section 2.3. Key parameters are varied intentionally to explore sensitivities and their relative impacts on total system costs and CO_2 emissions. These are further explored in the sub-sections that follow.



Notes: All scenarios include immediate customer response at scale (mostly embedded/distributed solar PV, storage) and other short-term risk mitigation capacity to ensure adequacy gap is met (portfolio of technologies/options). RE – Renewable energy; Graph not to scale, illustration purposes only.
Sources: CSIR Energy Centre analysis; Meridian Economics

Figure 12. System cost relative to CO_2 emissions for pertinent study scenarios considered

<u>Scenario: IRP 2019 (DMRE)</u>

The **IRP 2019** (DMRE) scenario refers to the Promulgated IRP 2019 [3] which was published by the Department of Mineral Resources and Energy (DMRE) in October 2019.

The promulgated IRP 2019 includes the annual capacities of new generation options required between 2022 and 2030 to meet forecasted demand. This scenario considers all input assumptions defined in the IRP 2019 including pertinent input assumptions like new technology costs, Eskom generation fleet

EAF, generation fleet decommissioning dates (including coal fleet decommissioning - 50-year life), carbon emissions constraints and annual new-build constraints on technologies (wind and solar PV).

The IRP 2019 horizon extends to 2030 only. In order to enable a further long-term understanding of the IRP 2019, the CSIR extended the time horizon from 2030 to 2050 and optimised new-build investment needs utilising the same input assumptions in the IRP 2019.

Scenario: Current Policy (Reference)

The **Reference** scenario is based on current policy to 2030 (IRP 2019) and as a result assumes the same new build capacity as the IRP 2019 (up to 2030). This scenario was modified with the following changes:

- Lower demand forecast;
- Lower Eskom plant performance projection (EAF);
- Updated new technology costs and learning assumptions; and
- Removal of annual new-build limits on wind and solar PV from 2031 onwards

The demand forecast, Eskom fleet EAF and new technology cost assumptions were adjusted to align with the most recent information and projections available at the time of the study and are outlined further in section 2.3. However, coal fleet decommissioning is still aligned with the IRP 2019 (50-year life).

Scenario: Least-cost

The **Least-cost** scenario assumes the same input assumptions as the Reference Scenario but with the following changes:

- Removal of the IRP 2019 policy adjusted capacity that is built prior to 2030, i.e. all new build capacity is optimized based on least-cost for the entire time horizon.
- Endogenous decommissioning of the Eskom coal fleet based on least-cost

Scenario: Modest RE Industrialisation program

The **Modest RE Industrialisation program** scenario builds on the outcomes of the Least-cost scenario where a more practical and implementable renewable build program is tested. This RE deployment scenario aims to smooth the wind and solar PV annual new build over the planning horizon in order to represent a more sustainable and achievable build-out programme considering the already known outcomes from the Least-cost scenario. Thus, this scenario assumes the same input assumptions as the Least-cost scenario but with the following change:

- Dynamic minimum annual build limits on wind and solar PV from 2022 onwards (described further in section 2.3.8).

Scenario: Ambitious RE Industrialisation

The **Ambitious Renewable Energy (RE) Industrialisation** scenario also forces a minimum annual wind and solar PV build out but with the following change:

- More Ambitious wind and solar PV build-out than the Modest RE Industrialisation (to achieve a lower carbon emissions trajectory).

Scenario: Ambitious RE Industrialisation with all coal retired by 2040

The **Ambitious RE Industrialisation (coal off by 2040)** scenario also forces a minimum annual wind and solar PV build out as per the Ambitious RE Industrialisation scenario but also enforces that all coal-fired capacity is retired by 2040. This is a representative scenario to test a "what if" hypothesis but could be repeated for any year where the choice for all coal to be decommissioned is opted for.

Scenario: 2Gt CO_2 budget

The **2Gt CO_2 budget** scenario assumes the same input assumptions as Least-cost but with the following change:

- A total CO_2 budget constraint of 2 Gt applied for the period 2020 – 2050.

Table 1. Summary of main study scenarios

Parameter	**IRP 2019** (DMRE)	**Reference** (CSIR)	**Least-cost** (CSIR)	**RE Industrialisation** (Modest/Ambitious) (CSIR)	**Ambitious RE Ind. coal retired by 2040** (CSIR)	**2Gt CO2 budget** (CSIR)
Demand [TWh]	306 (2030) 382 (2050)	285 (2030) 355 (2050)	285 (2030) 355 (2050)	285 (2030) 355 (2050)	285 (2030) 355 (2050)	285 (2030) 355 (2050)
EAF, [%] (Eskom existing/under constr.)	73% (2020) 76% (2030) 83% (2050)	66% (2020) 65% (2030) 82% (2050)	66% (2020) 65% (2030) 82% (2050)	66% (2020) 65% (2030) 82% (2050)	66% (2020) 65% (2030) 82% (2050)	66% (2020) 65% (2030) 82% (2050)
CO_2 mitigation	PPD (Moderate)	PPD (Moderate)	No constraint	No constraint	No constraint	2 Gt (2020-2050)
VRE build limits	1.0 GW/yr (solar PV), 1.6 GW/yr (wind)	None	None	Minimum limits (See section 2.4)	Minimum limits (See section 2.4)	None
Forced technologies	Coal, storage, hydro (import)[1]	Coal, storage, hydro (import)[1]	None	None	None	None
Technology costs	As per IRP 2019	See section 2.4	See section 2.4	See section 2.4	See section 2.4	See section 2.4
Coal fleet decommissioning	As per IRP 2019 (50 year life)	As per IRP 2019 (50 year life)	Endogenous decommissioning[2]	Endogenous decommissioning[2]	All coal retired by 2040	Endogenous decommissioning[2]
Short-term mitigation	Included[3]	Included[3]	Included[3]	Included[3]	Included[3]	Included[3]

NOTES: EAF – Energy Availability Factor; PPD – Peak Plateau Decline; [1] As per IRP 2019 (Table 5); [2] Economically optimal decommissioning of coal fleet (based on least-cost);
[3] Included immediate customer response at scale (mostly embedded/distributed solar PV, storage) and other short-term risk mitigation capacity to ensure adequacy gap is met (portfolio of technologies/options)
Sources: IRP 2019; CSIR; Meridian Economics

2.3 Input assumptions

This section outlines the main sources of data to inform input assumptions considered for the study. Publicly available information was used as far as possible and referenced accordingly. The main sources of information used were obtained from the following:

1. Information authored by Eskom and available in the public domain. This information took two main forms:
    i. Information and data available on the Eskom website (technical reports or media briefings); and
    ii. Direct interactions and interviews with Eskom employees with intimate knowledge of Eskom operations, related air quality compliance matters and the coal supply sector.
2. Technical articles and reports available in the public domain from other sources.
3. Domain experts with deep knowledge of the South African power system

Most of the input assumptions in the Reference scenario are aligned with the IRP 2019 [3]. Other scenarios deviate from inputs assumptions in the IRP 2019 and these are documented in this section.

2.3.1 Demand forecasts

Figure 13 and Figure 14 show the annual energy and peak demand for the two demand forecasts considered in this analysis. Similarly, the previously promulgated IRP 2010 demand forecast is shown for reference and relative comparison.

The IRP 2019 demand forecast is based on the IRP 2019 “median” demand [3] and was developed using statistical methods [11]. This forecast is based on an average 4.4% annual GDP growth to 2030 and 3.7% thereafter to 2050 but with notable change in the electricity intensity of the manufacturing and commercial sector of the economy. This result being an average annual electricity demand growth of 1.8% to 2030 and 1.1% thereafter to 2050. The demand forecast is inclusive of the entire RSA electrical demand, of which approximately 98% is currently met by Eskom-owned generators and IPP’s.

The “Updated” demand forecast is a scenario developed by the CSIR which essentially assumes a slower uptake in demand in the short term. This demand forecast is based on the Eskom MTSAO [12] demand forecast (until 2024) and assumes the same IRP 2019 annual growth rates thereafter. As can be seen, the IRP 2019 annual energy demand is expected to grow from 246 TWh today to roughly 306 TWh by 2030 and 382 TWh by 2050, while the lower demand forecast is expected to reach 285 TWh and 355 TWh in 2030 and 2050 respectively. The Updated demand forecast was assumed for all scenarios excluding the IRP 2019 (DMRE) scenario.

The annual demand forecasts are converted into hourly electricity demand profiles based on the historical actual hourly demand in South Africa in 2017. This profile was assumed to remain unchanged throughout the planning horizon (monthly average diurnal profile shown in Figure 15). The winter peaking nature of the South African power system is clearly demonstrated in Figure 15. Similarly, the morning and evening peak become more accentuated in winter months as residential space heating shifts the diurnal profile.

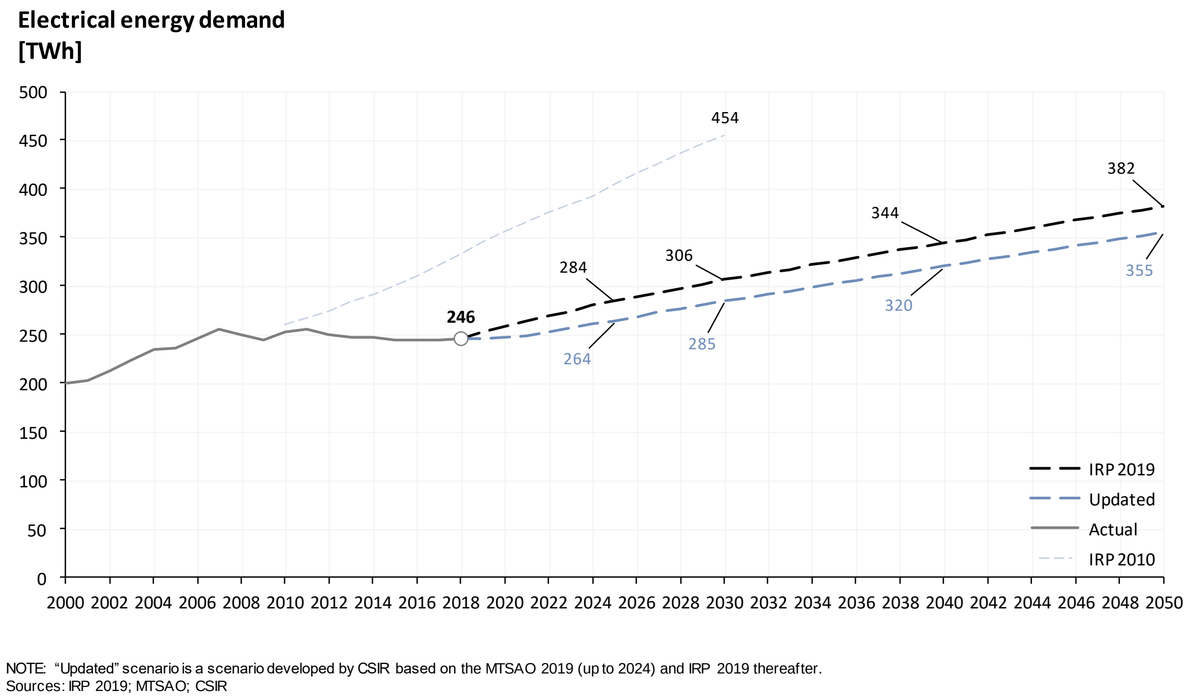


Figure 13. Historical and forecasted annual electrical energy demand for RSA

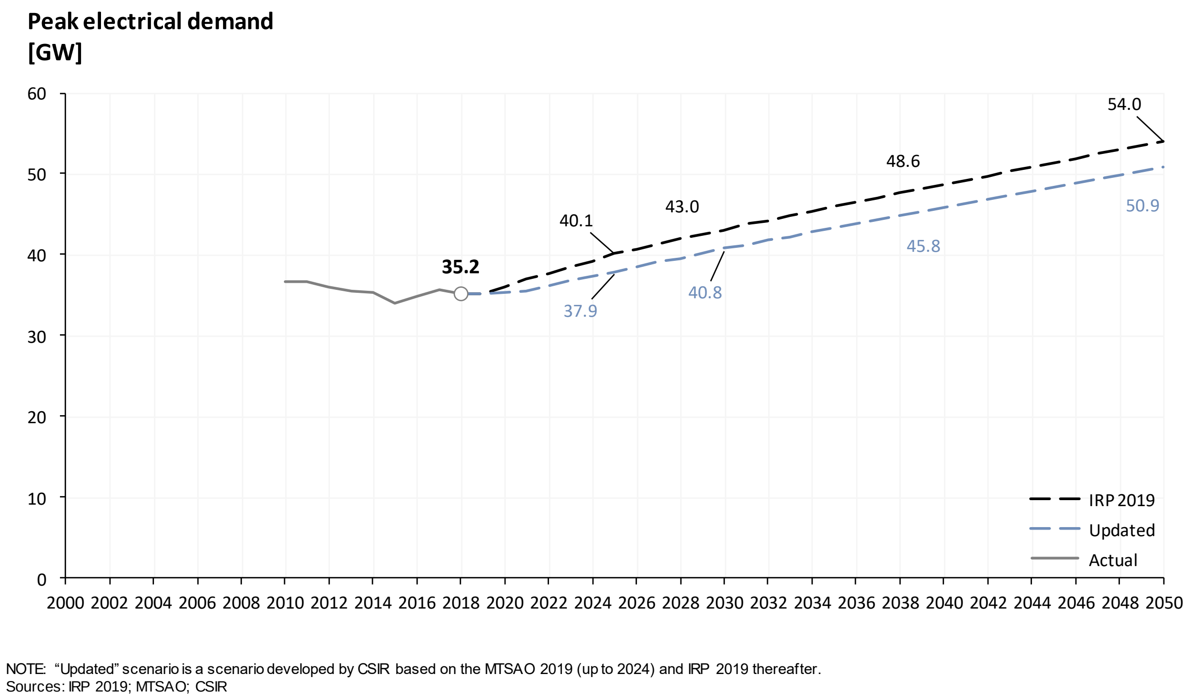


Figure 14. Historical and forecasted annual electrical peak demand for RSA

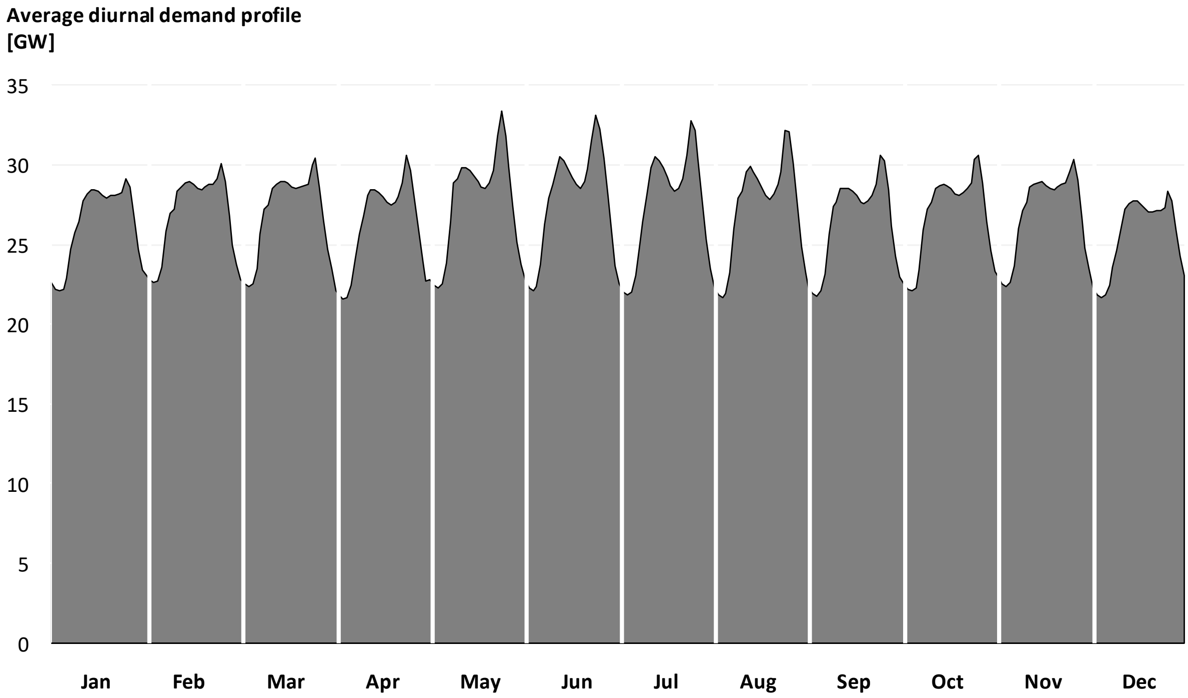


Figure 15. Historical monthly average diurnal hourly demand profile (2017), showing larger variances in peak demand during winter months than summer months

2.3.2 Existing generation fleet

The following sections outline the existing generation fleet assumptions used in this analysis.

2.3.2.1 Installed capacities and technology types

Table 2 summarizes the existing capacity assumptions in the year 2019 based on the IRP 2019 [6], the Eskom MTSAO [12] and Eskom [13]. The decommissioning dates for all non-coal technologies are as per the IRP 2019, whilst the assumptions on decommissioning of coal-fired power stations depends on the study scenario as described in section 2.2.

Table 2. Existing generation capacity in 2019 in South Africa (including import hydro) assumed in this study

Conventional Technologies	Nominal Capacity [MW]
Coal	**37 902**
Arnot	2 232
Camden	1 480
Duvha	2 875
Grootvlei	187
Hendrina	1 092
Kendal	3 840
Komati	200
Kriel	2 850
Lethabo	3 558
MajubaDry	1 842
MajubaWet	2 001
Matimba	3 690
Matla	3 450
Tutuka	3 510
Kusile	720
Medupi	3 615
Sasol Coal	600
Kelvin (Municipal)	160
Nuclear	**1 860**
Koeberg	1 860
Gas	**425**
Sasol Infragas	175
Sasol Synfuel Gas	250
Peaking	**3 405**
Acacia	171
Ankerlig	1 323
Avon (REIPPPP)	670
Dedisa (REIPPPP)	335
Gourikwa	735
PortRex	171

Renewable Technologies	Nominal Capacity [MW]
Hydro	**2 177**
CahoraBassa	1 500
ColleyWobbles	65
Gariep	360
Small Hydro (REIPPP)	12
Vanderkloof	240
Biomass-gas	**282**
Mondi	120
Sappi	144
Landfill Gas REIPPPP	18
CSP	**500**
CSP REIPPPP	500
Solar	**1 479**
Solar PV REIPPPP	1 479
Wind	**2 086**
Sere	100
Wind REIPPPP	1 986

Storage Technologies	Nominal Capacity [MW]
Pumped Storage	**2 912**
Drakensberg	1 000
Ingula	1 332
Palmiet	400
Steenbras	180

Figure 16 summarises the total existing, under construction and committed capacity in South Africa. With respect to coal capacity availability (and related EAF calculation), this study did not adjust any existing coal capacity which Eskom may already have or are planning to place in cold reserve temporarily as this information was not available at the time of conducting this study. As a cost saving measure, Eskom occasionally places coal units into cold reserve or extended cold reserve. Generators in cold reserve are taken offline but are available to be called back into service at short notice (12 to 16 hours), whilst plant in extended cold reserve are considered unavailable, as it takes five or more days to return it to service [14]. Thus, the Eskom fleet published EAF is improved when poor performing coal units are placed in cold reserve as these units are then assumed to have 100% availability.

It is clear that existing nuclear generation capacity at Koeberg (1.8 GW) is extended beyond 2024 as steam generators are replaced and life-extend Koeberg to 2044 (as expected) [3]. Other capacity that is decommissioned over the time horizon (as planned) include existing OCGTs, solar PV, wind and CSP capacity.

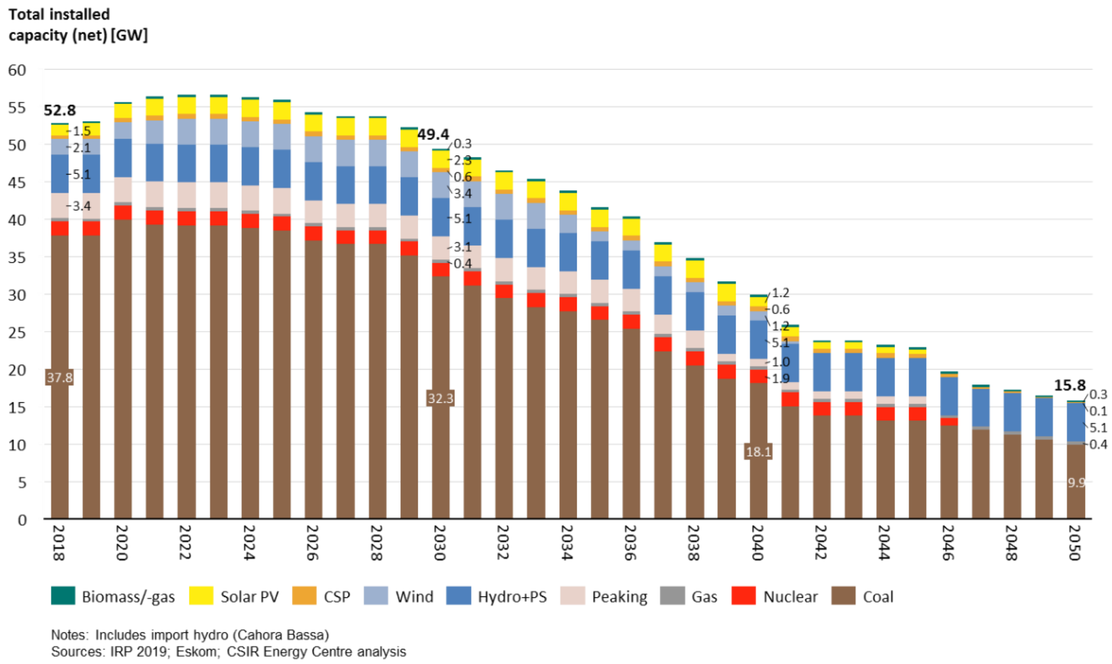


Figure 16. Total existing, under construction and committed capacity in South Africa for the period 2018-2050 (as per IRP 2019)

With the exception of the DMRE IRP 2019 scenario, endogenised decommissioning of the existing coal fleet was included in all of the scenarios. To date none of the published IRP plans nor other literature have allowed or considered earlier decommissioning of the South African coal fleet. It should be noted that no decommissioning costs or refurbishment costs for life extension beyond the expected 50-year life for the coal fleet were included. Similarly, this applies for all other generation technologies. The optimisation model was configured to allow coal stations to either run to their full 50-year technical life or decommission prior to this date if it is economical to do so. Thus, there is a natural balance between carrying the costs of existing coal generation capacity until the planned decommissioning date relative to the costs of decommissioning earlier and using other existing generation or building new generation capacity instead.

Each of the coal stations were modelled on a unit level and as such, partial decommissioning of each station is possible if it is economic to do so. An additional constraint was imposed to ensure that coal stations decommission at a pace of one (1) unit per year (two (2) units per year for smaller unit sizes) in line with the decommissioning schedules in the IRP 2019.

For technical operational reasons, a minimum annual average capacity factor constraint of 35% was considered on all existing coal generation capacity. Thus, with a minimum annual average capacity factor constraint of 35%, the continued operation of coal capacity (until 50-year life) is optimized relative to other existing and new-build options. Earlier than planned decommissioning of coal generation capacity would then occur if other alternatives were more economically optimal (it is uneconomical for existing coal capacity to remain in the power system before 50-year life is reached).

There is currently no available literature on the minimum capacity factors at which the existing South African coal fleet can technically operate. However, a brief analysis of minimum capacity factor calculated as a function of EAF and minimum stable level (MSL) for any generic power generator is shown in Table 3. It is important to remember that this is for an individual generator or a fleet of generators with the same MSL and EAF (which is not the case in reality). In reality, there would be a distribution of minimum capacity factors across the generators in the fleet as a function of their individual EAF and MSL. The range of minimum capacity factors for EAF range of 70-80% and MSL of 55-65% is highlighted in red. This is a likely range for the South African coal fleet which results in average fleet minimum capacity factor of ≈39-52%.

From an international perspective, the Indian coal fleet is seeing declining capacity factors in recent years from the highs of 2007/08 (78%) down to 60% in 2017/18 [15]. For two scenarios explored in [16], half of the Indian coal fleet is expected to be less than 63% and 51% with and without additional wind and solar PV (100 GW and 60GW) respectively. The distribution of capacity factors as part of the study undertaken in [16] is what is most insightful – one quarter of the Indian coal fleet exhibits a capacity factor of less than 44% without the additional renewable energy but a capacity factor as low as 12% with the additional renewable energy. Similar findings are made in [17] where 150 GW of the Indian coal fleet would exhibit a capacity factor of 20% or less by 2027. In [18], coal fleet capacity factors across 16 countries/regions with Brazil, non-OECD Europe, Other Americas, Russia exhibit capacity factors of less than 50% (lowest is 21% in the Middle East). In the USA, more recent trends are showing coal capacity being retired as a result of notably low capacity factors of less than 55% relative to previously where capacity factors were almost always above 60% [19]. In Southeast Asia - Indonesia's coal fleet exhibited capacity factors as low as 51%, 63% in Indonesia, 58% in Malaysia, 53% in the Philippines and 53% in Vietnam [20]. Particularly, in Vietnam capacity factors of as low as 46% have been noted in [21]. The need for increased flexibility from coal-fired generation capacity is clearly evident in international jurisdictions with large existing and/or planned coal generation fleets already and will become increasingly important as higher penetration levels of variable renewable energy are deployed [22], [23].

Table 3. Minimum capacity factor relative to energy availability factor (EAF) and minimum stable level (MSL) for a generic generator.

EAF [%] / MSL [p.u.]	50	52.5	55.0	57.5	60.0	62.5	65.0	67.5	70.0	72.5	75.0	77.5	80.0
30.0	15.0	15.8	16.5	17.3	18.0	18.8	19.5	20.3	21.0	21.8	22.5	23.3	24.0
32.5	16.3	17.1	17.9	18.7	19.5	20.3	21.1	21.9	22.8	23.6	24.4	25.2	26.0
35.0	17.5	18.4	19.3	20.1	21.0	21.9	22.8	23.6	24.5	25.4	26.3	27.1	28.0
37.5	18.8	19.7	20.6	21.6	22.5	23.4	24.4	25.3	26.3	27.2	28.1	29.1	30.0
40.0	20.0	21.0	22.0	23.0	24.0	25.0	26.0	27.0	28.0	29.0	30.0	31.0	32.0
42.5	21.3	22.3	23.4	24.4	25.5	26.6	27.6	28.7	29.8	30.8	31.9	32.9	34.0
45.0	22.5	23.6	24.8	25.9	27.0	28.1	29.3	30.4	31.5	32.6	33.8	34.9	36.0
47.5	23.8	24.9	26.1	27.3	28.5	29.7	30.9	32.1	33.3	34.4	35.6	36.8	38.0
50.0	25.0	26.3	27.5	28.8	30.0	31.3	32.5	33.8	35.0	36.3	37.5	38.8	40.0
52.5	26.3	27.6	28.9	30.2	31.5	32.8	34.1	35.4	36.8	38.1	39.4	40.7	42.0
55.0	27.5	28.9	30.3	31.6	33.0	34.4	35.8	37.1	38.5	39.9	41.3	42.6	44.0
57.5	28.8	30.2	31.6	33.1	34.5	35.9	37.4	38.8	40.3	41.7	43.1	44.6	46.0
60.0	30.0	31.5	33.0	34.5	36.0	37.5	39.0	40.5	42.0	43.5	45.0	46.5	48.0
62.5	31.3	32.8	34.4	35.9	37.5	39.1	40.6	42.2	43.8	45.3	46.9	48.4	50.0
65.0	32.5	34.1	35.8	37.4	39.0	40.6	42.3	43.9	45.5	47.1	48.8	50.4	52.0
67.5	33.8	35.4	37.1	38.8	40.5	42.2	43.9	45.6	47.3	48.9	50.6	52.3	54.0
70.0	35.0	36.8	38.5	40.3	42.0	43.8	45.5	47.3	49.0	50.8	52.5	54.3	56.0

2.3.2.2 Minimum emission standards compliance

In terms of the National Environmental Management: Air Quality Act, 2004 (Act No. 39 of 2004) (NEMAQA) [24], all of Eskom's coal and liquid fuel-fired power stations are required to meet Minimum Emission Standards (MES). Eskom have argued that full MES compliance will result in *"increased water consumption; transport and mining impacts related to the supply of sorbent (limestone/lime) and increases in waste and CO_2 production"* [25]. Eskom have also highlighted that MES compliance will result in a significant increase in the electricity tariff. In this regard, Eskom have applied for a combination of postponements, suspensions and alternative MES limits for their various power stations.

This study assumes a specific Eskom MES compliance which includes relaxed compliance measures, as obtained in [26]. This information is summarized in Figure 17 and is provided in further detail in Table 4. The associated costs for MES retrofits as listed in Table 4 are included in all scenarios. This information reveals that Eskom intends only on adding flue-gas desulphurization (FGD) for SO_x abatement at Kusile and Medupi (other power plants remain without these retrofits) whilst other retrofits to address NOx and PM include low NOx burners (LNBs), Electrostatic Precipitators (ESPs) and Fabric Filter Plants (FFPs) across a number of other existing coal capacity.

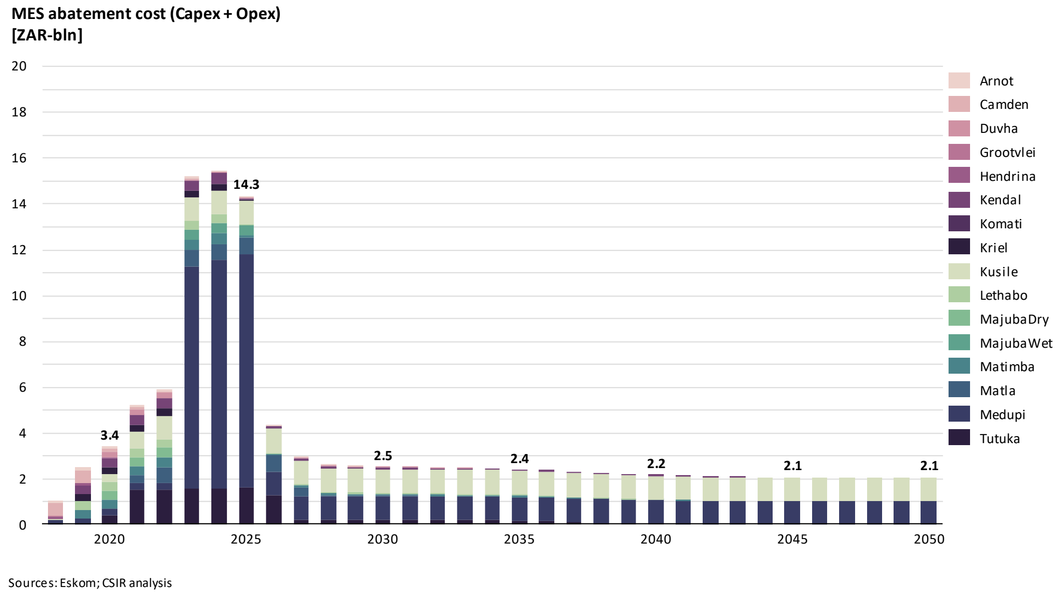


Figure 17. MES abatement total cost per station per year (CAPEX and OPEX) aligned with abatement schedule shown in Table 4

Table 4. MES retrofit schedule for Eskom power plants assumed in this study[3]

	Planned Retrofit	Pollutant to be abated	Capex in year 1, in ZAR2018/kW	Opex per year in ZAR2018/kW /year	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/ 30
Kusile	Fully compliant	N/A	n/a	n/a															
Medupi	FGD	SO_2	5560	147															
Majuba	LNB	NOx	587	2.15															
Kendal	HFT+ESP upgrade	PM	537	14															
Kendal	FGD-Pilot	SO_2	4211	227															
Matimba	FGD-Pilot	SO_2	4211	227															
Matimba	HFT+ESP upgrade	PM	537	14															
Lethabo	HFT+ESP/SO_3 upgrade	PM	537	14															
Tutuka	FFP	PM	1697	44															
Tutuka	LNB	NOx	587	2.15															
Duvha (4 & 6)	HFT+ESP upgrade	PM	537	14															
Matla	HFT +ESP upgrade	PM	537	14															
Matla	LNB	NOx	587	2.15															
Kriel	HFT+ESP upgrade	PM	537	14												Dx1	Dx1	Dx1	Dx2
Arnot	FFP installed	N/A	n/a	n/a							Dx1					Dx2	Dx1		Dx2
Hendrina	FFP installed	N/A	n/a	n/a			SDx1	SDx2	SDx1	SDx2 Dx1	SDx3 Dx2	SDx1 Dx1	Dx1	Dx2	Dx1	Dx1	Dx1		
Camden	FFP installed, LNB complete	NOx	587	2.15						Dx1	Dx2	Dx2	Dx3						
Grootvlei	FFP complete	N/A	n/a	n/a			SDx3		SDx2	SDx1					Dx1	Dx1	Dx2	Dx2	
Komati	No commitments	N/A	n/a	n/a			SDx2	SDx3	SDx2		SDx1	SDx1		Dx2		Dx1	Dx4	Dx1	Dx1

Legend

Completed projects	
Future projects	
Decommissioning	D
Shut down for reserve storage	SD
Previous commitment	

[3] FFP = Fabric Filter Plant; ESP = Electrostatic Precipitators; HFT = High frequency transformer; FGD = Flue Gas Desulphurisation

2.3.2.3 Energy Availability Factor of Eskom generation fleet

The existing Eskom fleet of power generators in South Africa is predominantly made up of coal-fired power plants. As shown in Figure 18, the Energy Availability Factor (EAF) of the Eskom generation fleet has been declining over the last 20 years, driven by a number of factors including an ageing coal fleet, maintenance protocols, financial and governance challenges. The EAF is a capacity weighted average annual EAF across all Eskom generation capacity (coal, nuclear, gas, hydro and pumped storage). The 2020 YTD (week 27) EAF was 65.7%.

The IRP 2019 considers the reliability of the Eskom fleet via the abovementioned EAF and expects EAF to follow the path shown in Figure 18. In the IRP 2019, the fleet EAF performance is planned to improve from 67% in 2019 to 75.5% by 2023 and remain constant at 75.5% thereafter until 2030. The CSIR projected EAF beyond 2030 is an implicit calculation of EAF that will continue to increase steadily, driven by decommissioning of the poorer performing older coal fleet.

The “Updated” EAF expectation shown in Figure 18 is based on the Eskom MTSAO “Low MES 1” scenario up to 2024 [27] and increases thereafter, again driven by the planned decommissioning of the existing coal fleet.

The station level EAF used in this analysis were adapted from IRP 2019 [3], with generic technology specific assumptions made for the split between annual planned and unplanned outage factors.

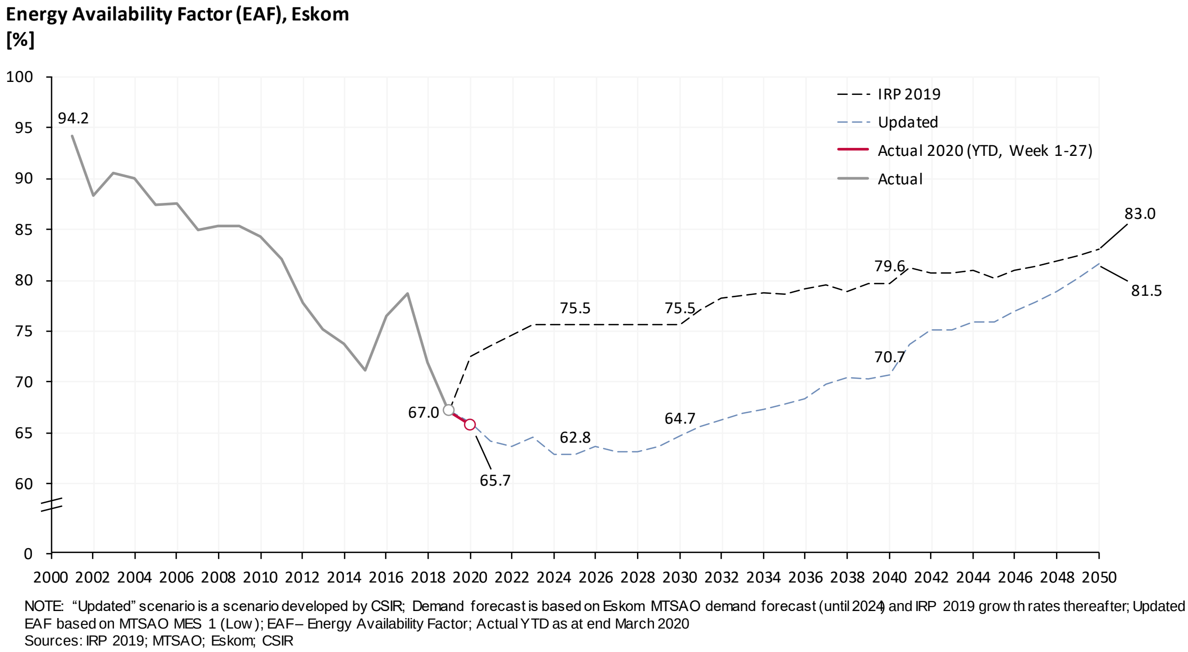


Figure 18. Annual EAF assumptions for the Eskom generation fleet (2018-2050) assumed in the IRP 2019 as well as the updated EAF forecast assumed in this analysis

2.3.3 Fuel costs

The dominant component of fuel costs comes from coal-fired generation capacity. Coal costs used as part of this study are summarised in Figure 19. This is based on [28] and [29]. No increase in coal costs are considered for the time horizon (in real terms). The implicit efficiency of the existing coal fleet is included in Figure 19 as the conversion of coal fuel (R/t) into electricity (R/MWh) is shown. It is clear that improved efficiency of conversion of coal to electricity would result in reduced absolute emissions as the efficiency of the Eskom coal fleet is improved but the relative costs of this improvement will still need to be established. As part of this study, the efficiency of the coal fleet begins at ≈31% (but changes as coal capacity is decommissioned over the time horizon). This aligns well with public domain Eskom information showing how Eskom coal fleet efficiency has declined slightly over the past decade from 33.1% in 2009 to 31.0% in 2019 [13].

Costs for other fuels used in power generation (diesel, jet fuel, natural gas and others) are aligned with costs provided in the IRP 2019 [3]. Relatively expensive natural gas has been assumed for this study as aligned with the IRP 2019 (150 R/GJ) but with no implicit assumption around sourcing of natural gas (domestic natural gas, regional pipeline imports, LNG port imports). Liquid fuel costs for existing OCGTs are also aligned with IRP 2019.

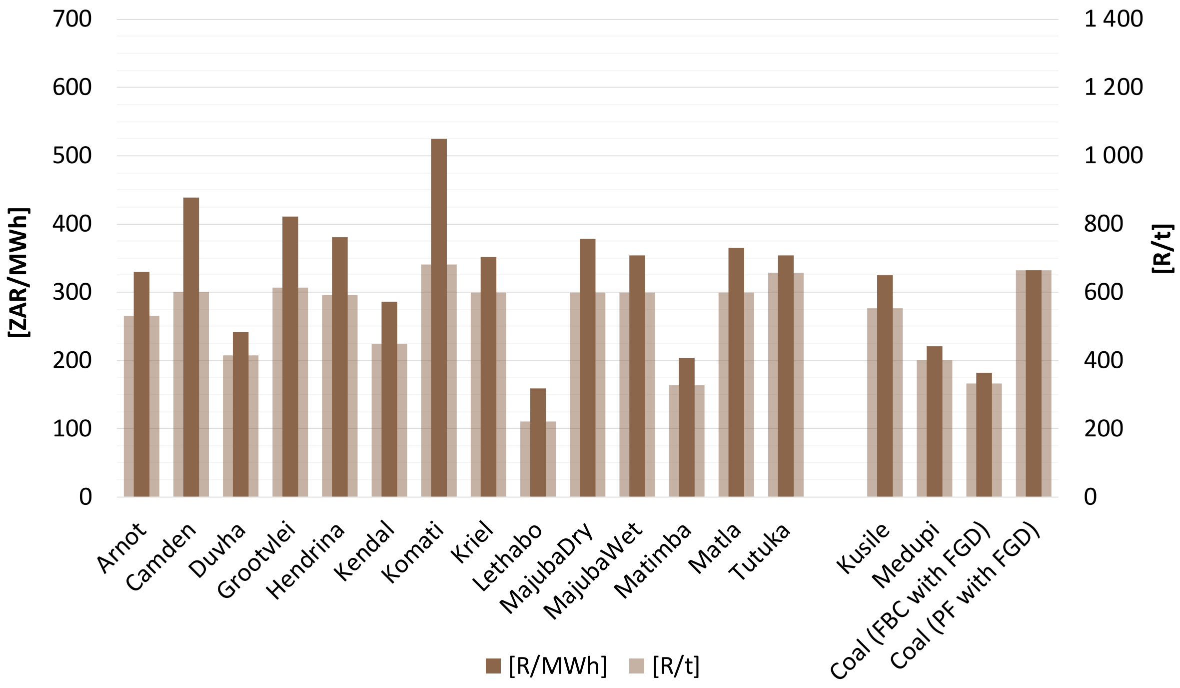


Figure 19. Coal cost assumptions in R/MWh and R/t considered for this study per power station [28],[29]

2.3.4 Operating reserves and reliability requirements

A core aspect that needs to be carefully considered in a capacity expansion plan is that of system adequacy. Any capacity expansion plan must adhere to an acceptable level of system adequacy (typically an input definition).

System adequacy can be measured using several metrics, including the use of deterministic planning reserve margins and unserved energy or probabilistic metrics such as the Loss of Load Probability (LOLP)/Loss of Load Expectation (LOLE).

Although the long-term capacity expansion obtained provides significant insight into the least-cost optimal long-term capacity and energy mix, the level of detail required to determine whether the expansion plan truly meets adequacy requirements is generally not sufficiently captured in the long-term capacity expansion formulation.

Thus, the approach taken in this analysis was a two-stage process. In the first stage, the long-term capacity expansion plan is obtained whereby the least-cost new build options are obtained. Following this, the second stage is then run whereby the chosen expansion plan is run with a significantly higher level of detail in a unit-commitment and economic dispatch production cost model. In this model, additional operational constraints are considered in the model including explicit reserve classes, minimum up/down times for generators and hourly chronology. The adequacy of the new build expansion plan can then be verified or iterated with the production cost model. The production cost model also inherently ensures that system flexibility requirements are met for all hours.

Due to computational restrictions, capacity expansion models typically use a limited number of representative days. Samples are taken of the days/weeks/months (typically an input definition) in the capacity expansion optimisation. Sampling is done statistically such that 'like' periods (days/weeks/months) are removed leaving a sample set that is representative of the variation in the original load. In this study, 15 representative days (24 hours per day) were used for each year in the planning horizon. Through carrying out the two-stage process described previously, it was found that to ensure all scenarios have an acceptable level of reliability, an explicit minimum reserve margin of 25% must be specified across all scenarios. This was a finding specific to the level of detail used in representing the load (15 days) in the capacity expansion plan and is in no way definitive nor a recommendation as to the optimal level of planning reserve margin for South Africa. A deep dive into existing, more appropriate and/or improved adequacy metrics was not the focus of this study and will be pursued separately in future.

The IRP 2019 does not explicitly mention operating reserve requirements. Thus, existing approaches taken to define the three reserve classes that make up operating reserves (Instantaneous, Regulating and 10-Minute) are informed by the Eskom Ancillary Services Technical Requirements for 2019/20 – 2023/24 [30].

The assumptions for reserve requirements for this study are summarized in Table 5 as taken from [30] up to the period of 2023/24. Without any additional information, assumptions thereafter are made based on the rules applied in [30] for Instantaneous, Regulating and 10-Minute reserve categories as far as possible. Each of these reserve categories are modelled explicitly for production cost model runs whilst the sum of all reserve categories is used in the long-term capacity expansion planning reserve requirement. Supplemental reserve is generating or demand side load that can respond in 6 hours or less to restore operating reserves. This reserve must be available for at least 2 hours. Emergency reserves should be fully activated within 10 minutes. Ten minute reserve is defined by the following formula:

Ten minute reserve requirement = Total Operating – Instantaneous – Regulating

Table 5. Assumed reserve requirements to 2050 (in MW) for the different reserve categories

			2016 - 2020	2020 - 2025	2025 - 2030	2030 - 2040	2040 - 2050
Instantaneous	**Summer**	**Peak**	500 - 650	650 - 650	650 - 650	650 - 650	650 - 650
		Off-peak	800 - 850	850 - 850	850 - 850	850 - 850	850 - 850
	Winter	**Peak**	500 - 650	650 - 650	650 - 650	650 - 650	650 - 650
		Off-peak	800 - 850	850 - 850	850 - 850	850 - 850	850 - 850
Regulating	**Summer**	**Peak**	450 - 450	450 - 600	600 - 670	670 - 820	820 - 970
		Off-peak	450 - 450	450 - 600	600 - 670	670 - 820	820 - 970
	Winter	**Peak**	550 - 550	550 - 720	720 - 790	790 - 970	970 - 1 150
		Off-peak	550 - 550	550 - 720	720 - 790	790 - 970	970 - 1 150
Ten-minute	**Summer**	**Peak**	1050 - 900	900 - 950	950 - 1 180	1180 - 1 930	1930 - 2 380
		Off-peak	750 - 700	700 - 750	750 - 980	980 - 1 730	1730 - 2 180
	Winter	**Peak**	950 - 800	800 - 830	830 - 1 060	1060 - 1 780	1780 - 2 200
		Off-peak	650 - 600	600 - 630	630 - 860	860 - 1 580	1580 - 2 000
Operating	**Summer**	**Peak**	2000 - 2 000	2000 - 2 200	2200 - 2 500	2500 - 3 400	3400 - 4 000
		Off-peak	2000 - 2 000	2000 - 2 200	2200 - 2 500	2500 - 3 400	3400 - 4 000
	Winter	**Peak**	2000 - 2 000	2000 - 2 200	2200 - 2 500	2500 - 3 400	3400 - 4 000
		Off-peak	2000 - 2 000	2000 - 2 200	2200 - 2 500	2500 - 3 400	3400 - 4 000
Supplemental	**Summer/ Winter**	**Peak/ Off-peak**	1300 - 300	300 - 300	300 - 300	300 - 300	300 - 300
Emergency			500 - 1 900	1900 - 1 900	1900 - 1 900	1900 - 1 900	1900 - 1 900
Total	**Summer/ Winter**	**Peak**	**3300 - 2300**	**2300 - 2500**	**2500 - 2800**	**2800 - 3700**	**3700 - 4300**
		Off-peak	**2500 - 3900**	**3900 - 4100**	**4100 - 4400**	**4400 - 5300**	**5300 - 5900**

2.3.5 Short-term emergency supply and distributed solar PV

Both the IRP 2019 [6] and the MTSAO [12] identified a potential supply gap of 2-3 GW between 2019 and 2022, whilst neither recommended specific demand or supply-side options to mitigate this gap. In January 2020, the CSIR conducted analyses on South Africa’s electricity crisis [31] and identified a number of key interventions to mitigate the expected short-term supply shortfall.

As summarized in Figure 20 and taken from [31], one of the identified mitigation options was a customer response at scale via embedded generation (EG) and distributed generation (DG) deployments. These total ≈3.4 GW by the end of 2022, mostly in the form of solar PV in the residential sector (0.5 GW), commercial and agricultural sectors (1.65 GW) and industrial sector (1.3 GW). Similarly, distributed storage of ≈1.4 GW is deployed by 2022.

Another identified supply option which could provide energy relatively quickly is roughly 200 MW of additional capacity from the existing wind and solar IPPs (“solar/wind REIPPP power up”). This is also included in Figure 20.

Finally, in December 2019, the DMRE issued a request for information (RFI) [10] in respect of the design of a risk mitigation Power Procurement Programme (RMPPP). The objective of the RFI was, amongst other things, to enable DMRE to consider the various options available to *“procure power generation capacity that can be connected to the grid as expeditiously as possible and at the least possible cost”*. This study assumes the optimisation of the remaining capacity and energy requirement following the abovementioned deployments, using peaking gas capacity as a proxy technology. It is also clear that the capacity that is part of the distributed response from customers (see Figure 20) could also be part of the DMRE RMPPP when implemented.

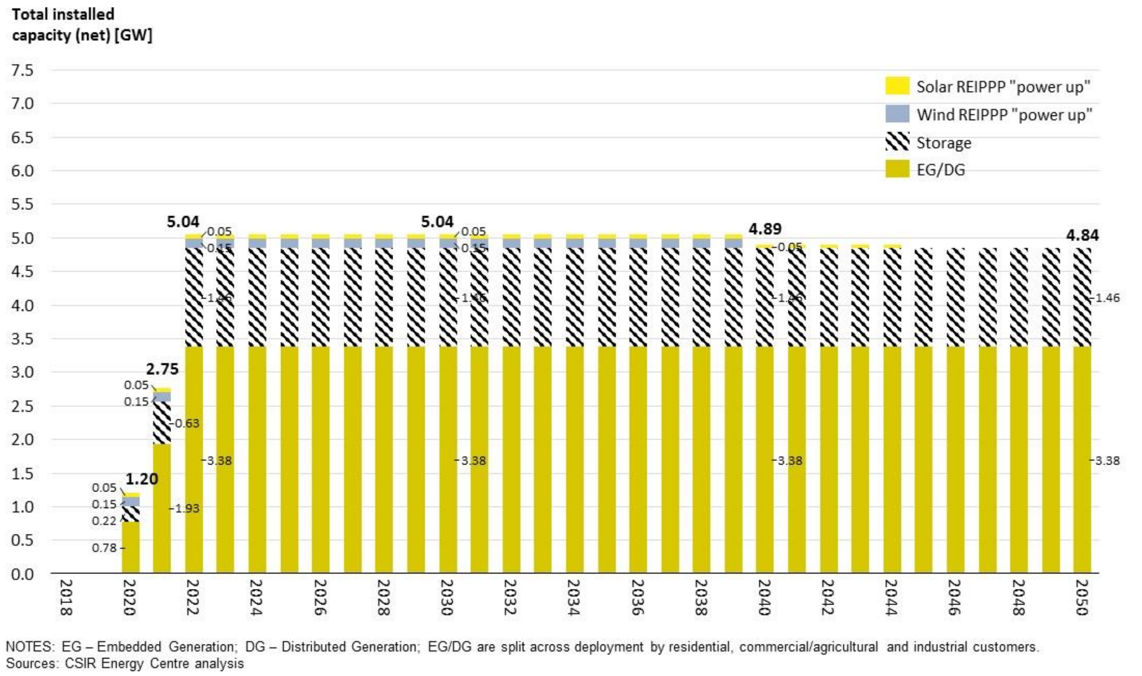


Figure 20. Cumulative installed capacity of customer response at scale short-term emergency supply options only (IRP 2019 expected capacity and optimised short-term capacity to meet gap nowt shown)

2.3.6 Supply technologies: Technical characteristics

Several technical characteristics for each supply technology have been specified in the capacity expansion and production cost modelling framework. Figure 21 shows the technical characteristics of a conventional dispatchable generator which were specified. These technical characteristics are included as technical constraints placed on the operational capability of the generator (at unit level).

An accurate representation of the technical capabilities of generators (or as accurate as possible) will become increasingly important as higher levels of variable renewable energy are integrated. Across all scenarios considered in this study, these characteristics are explicitly modelled and represented to ensure a technically feasible power system. As will be shown, operating of existing coal generators in the South African power system at lower capacity factors will necessitate increased levels of flexibility from the coal fleet.

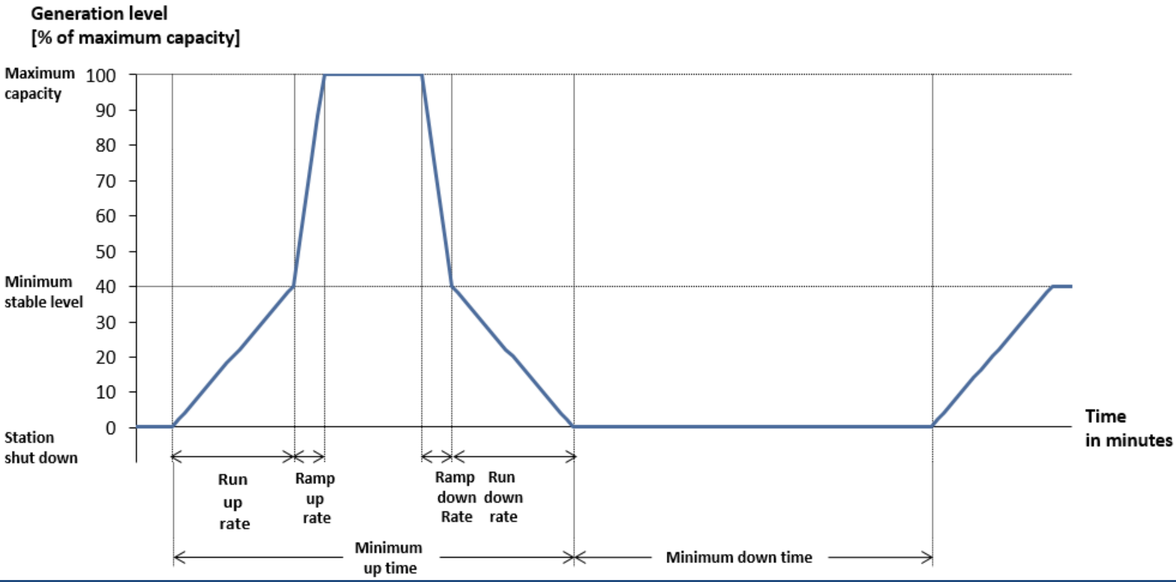


Figure 21. Representation of technical characteristics of dispatchable generators in the modelling framework.

Wind and solar PV power generators are assumed to be driven by defined profiles. These profiles are based on datasets that were obtained from the work done in [32] by the CSIR and uses the 27 supply areas (defined by Eskom). The wind and solar PV profiles for these 27 supply areas are aggregated into an equivalent solar PV and wind profile and used to define any new solar PV and/or wind power generator being built. The IRP 2019 uses the same dataset from [32] (albeit aggregated differently). As examples, wind and solar PV profiles for January and July are shown in Figure 22 and Figure 23 respectively.

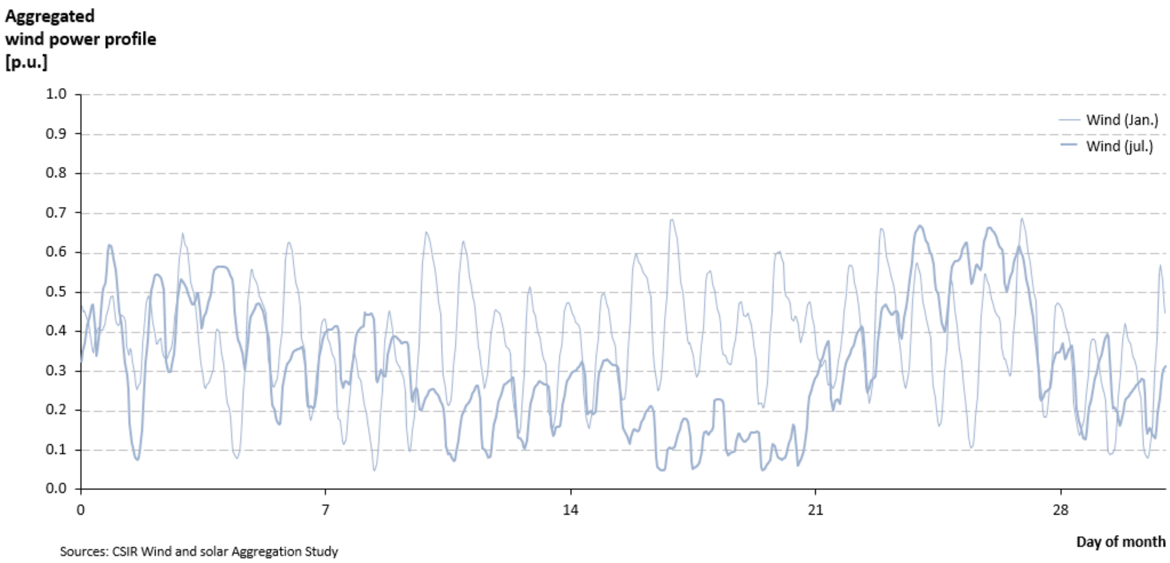


Figure 22. Aggregated wind profiles (normalized to 1, shown for January and July).

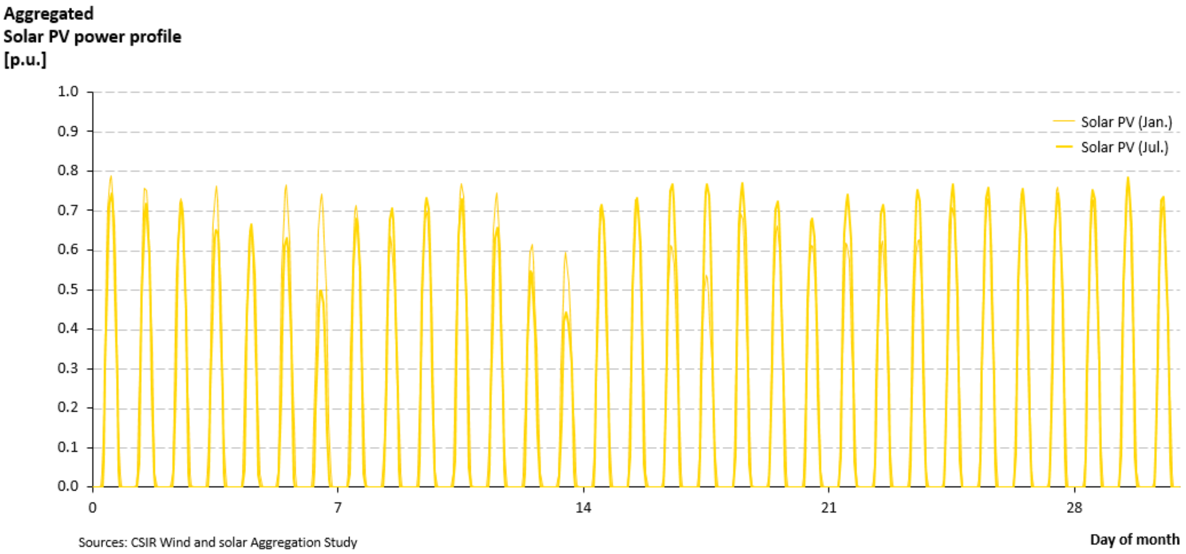


Figure 23. Aggregated solar PV profiles (normalized to 1, shown for January and July).

2.3.7 Supply technologies: New technology costs

Key input assumptions include overnight capital cost, construction time, capital phasing schedule, Fixed Operations and Maintenance (FOM), Variable Operations and Maintenance (VOM), fuel costs and efficiency (heat rate). The modelling framework does not consider the Leveled Cost of Electricity (LCOE) as an input parameter but considers all cost components explicitly as described above.

The costs for the new technologies considered are summarized in Appendix A[4]. Conventional supply technology input cost assumptions are aligned with the IRP 2019 and inflated to January-2019 Rands using Consumer Price Inflation (CPI).

Gas-fired generation capacity costs take the form of utility-scale OCGTs/GEs and CCGTs/GEs aligned with IRP 2019. The differentiation between gas turbines and gas engines is arbitrary at this stage as both technologies have similar cost characteristics (albeit not identical) and flexible capabilities that can be further investigated in future to further tune the technology investment necessary.

Coal technologies considered include pulverized fuel (PF), fluidized bed combustion (FBC) and Integrated Coal Gasification Combined Cycle (IGCC) power plants. Carbon Capture and Storage (CCS) for PF coal capacity was also considered. Without delving further into new-build coal technology costs as part of this study, it is clear that new-build coal generation capital cost with further investment to

[4] Demand side response (DSR) was not explicitly considered in this analysis.

mitigate CO_2 emissions (coal with CCS) would cost almost double that of new-build capacity without CCS.

Nuclear generation capacity costs are based on large-scale nuclear power as defined in the IRP 2019 and supporting studies [3], [33]. Small-scale nuclear costs are not readily available as these technologies have not yet been investigated for application in South Africa and have limited global operating experience or commercial operations thusfar.

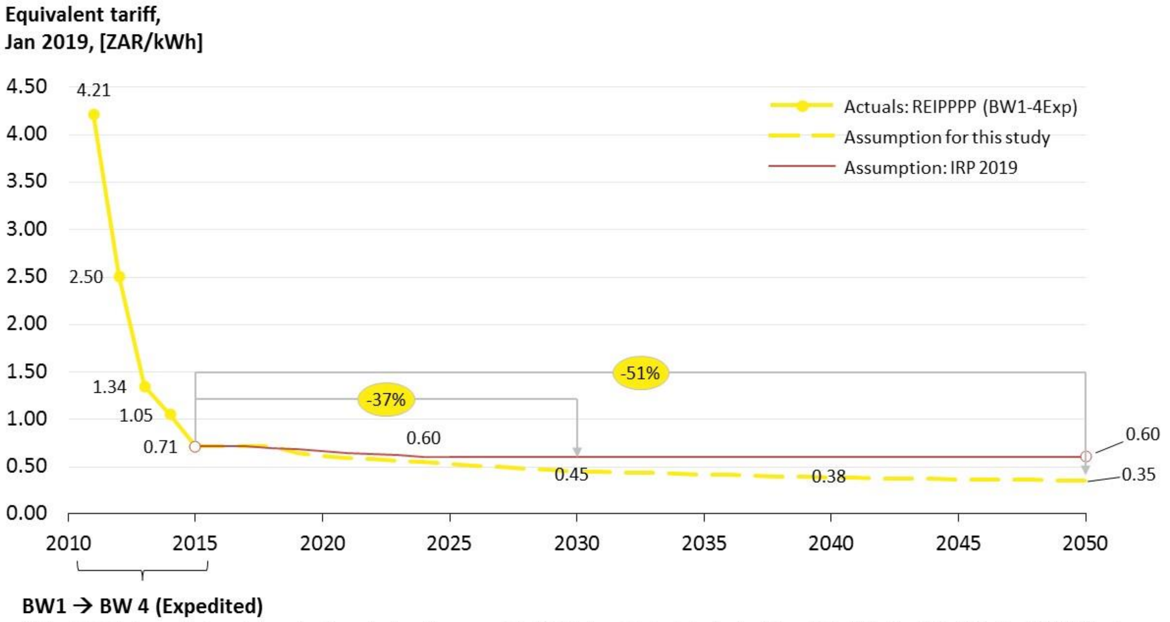
Supply technology costs for new-build wind and solar PV were developed using the REIPPPP Bid Window (BW) 4 (Expedited) equivalent tariff as a starting point (aligned with IRP 2019), with declining cost trajectories thereafter based on the National Renewable Energy Laboratory (NREL) annual technology baseline (ATB) technology learning assumptions [34]. Only CAPEX input assumptions for wind and solar PV were reduced in order to obtain the equivalent learning rate on the LCOE of these technologies.

Key differences between input assumptions for solar PV and wind in the IRP 2019 and the reference scenarios in this analysis are highlighted in Figure 24 - Figure 26 respectively. As can be seen, the IRP 2019 assumes the starting point for solar PV and wind to be similar to equivalent tariff levels achieved in the REIPPPP Bid Window (BW) 4 (Expedited). These are followed by a moderate level of further learning towards 2030 (15% for solar PV and wind) following which costs remain constant. This study assumes further declines for solar PV, aligned with NREL's ATB 2019 "Low" projection, whilst capex cost for wind declines are similar up to 2030, but continue to decline post-2030. This would result in an equivalent LCOE of ≈0.45 R/kWh for ground mounted solar PV and ≈0.60 R/kWh for wind by 2030.

This study assumes that the overnight cost of battery storage (specifically lithium ion technology) will decrease from ~370 USD/kWh installed today to ~200 USD/kWh installed by 2030 and ~150 USD/kWh installed by 2050 as shown in Figure 26. Stationary storage of 1-hour, 3-hour and 8-hour duration is included as expansion candidates in all scenarios.

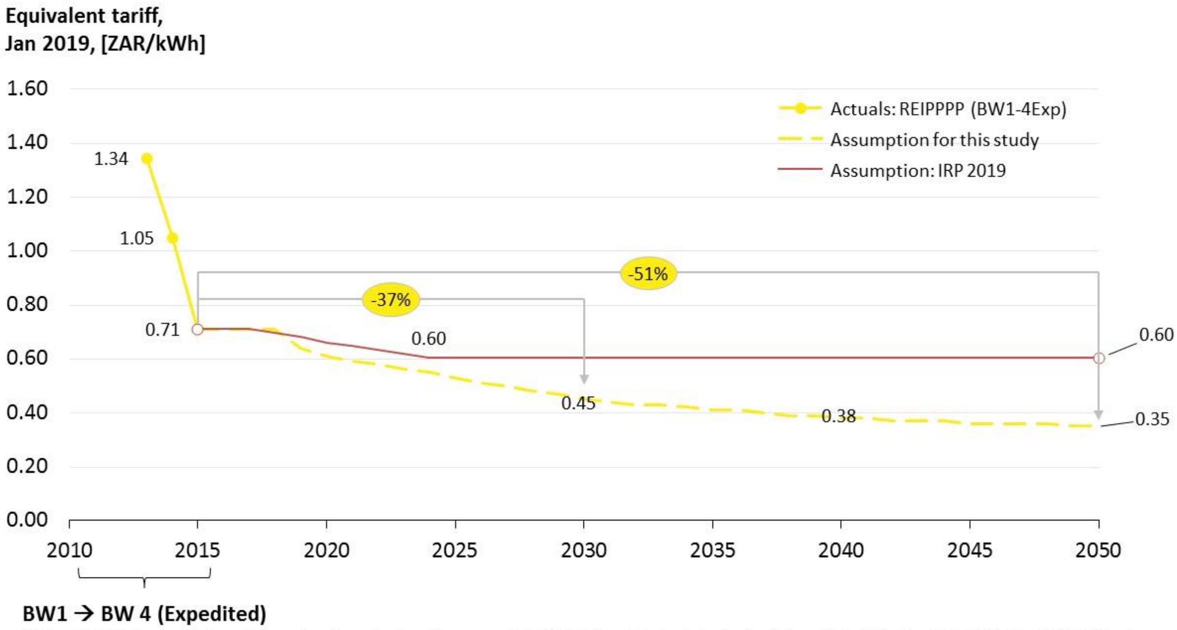
Pumped storage capacity is included as an expansion candidate in all scenarios with technical and cost characteristics aligned with that of Ingula as described in the IRP 2019 [3]. However, owing to the limited number of additional suitable sites for pumped storage capacity in South Africa, a maximum deployment of 5 000 MW is considered.

Only slight cost reductions in future are assumed for established thermal technologies such as nuclear and gas turbines as shown in Appendix A. New gas capacity is assumed to utilize natural gas at a cost of 150 R/GJ (proxy for imported liquefied natural gas (LNG) infrastructure delivered to the power station). No volume constraints on natural gas are imposed in this analysis. This fuel cost assumption is an inflated estimate from the IRP 2019 and is considered conservative.



Notes: REIPPPP = Renewable Energy Independant Power Producer Programme; BW = Bid Window; bid submissions for the different BWs: BW1 = Nov 2011; BW2 = Mar 2012; BW 3 = Aug 2013; BW 4 = Aug 2014; BW 4 (Expedited) = Nov 2015
Sources: StatsSA for CPI; South African Department of Energy (DoE); DoE IPP Office; CSIR analysis. Learning rate – NREL 2019 ATB "Low"

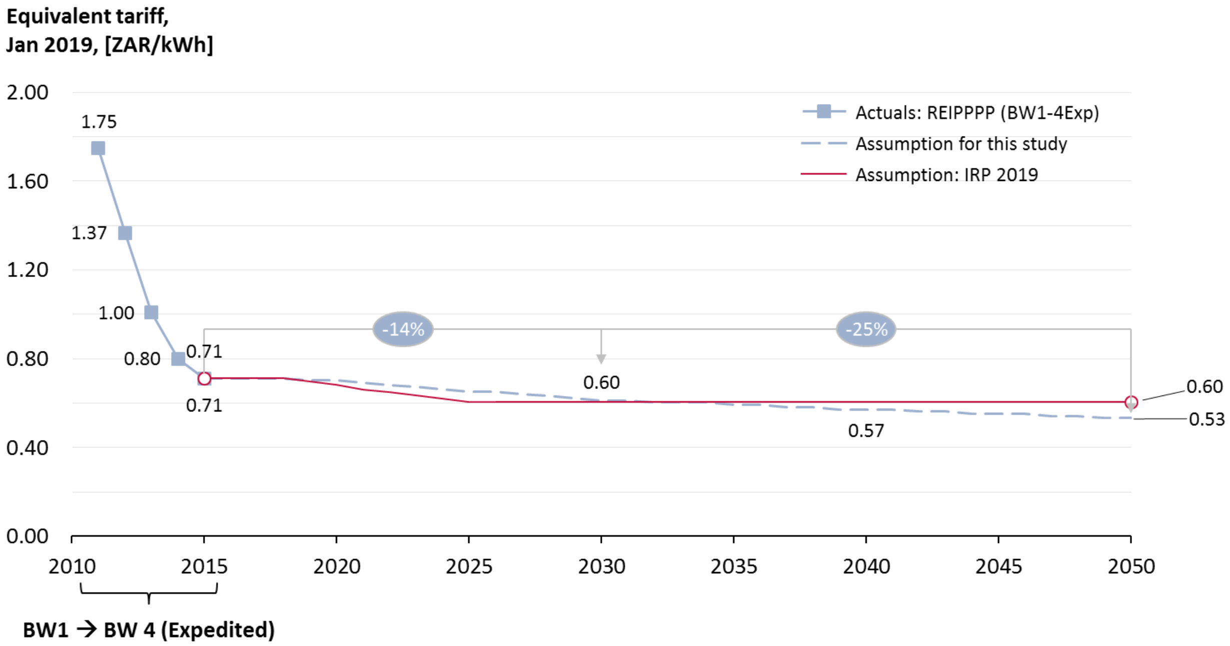
(a) Technology learning as part of REIPPPP drove down new-build solar PV energy



Notes: REIPPPP = Renewable Energy Independant Power Producer Programme; BW = Bid Window; bid submissions for the different BWs: BW1 = Nov 2011; BW2 = Mar 2012; BW 3 = Aug 2013; BW 4 = Aug 2014; BW 4 (Expedited) = Nov 2015
Sources: StatsSA for CPI; South African Department of Energy (DoE); DoE IPP Office; CSIR analysis. Learning rate – NREL 2019 ATB "Low"

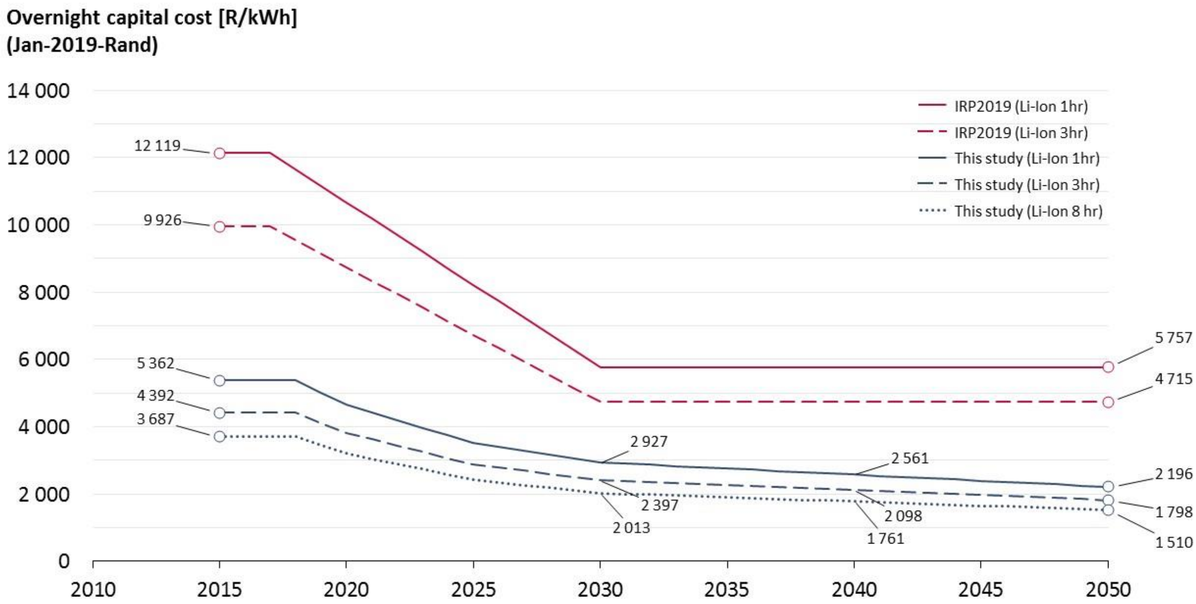
(b) Zoomed view indicating expected future learning for new-build solar PV energy

Figure 24. Equivalent cost assumption for solar PV based on fundamental cost structure of the technology (IRP 2019 and cost assumption for this analysis)



Notes: REIPPPP = Renewable Energy Independant Power Producer Programme; BW = Bid Window; bid submissions for the different BWs: BW1 = Nov 2011; BW2 = Mar 2012; BW 3 = Aug 2013; BW 4 = Aug 2014; BW 4 (Expedited) = Nov 2015
Sources: StatsSA for CPI; South African Department of Energy (DoE); DoE IPP Office; CSIR analysis . Learning rate – NREL 2019 ATB "Mid"

Figure 25. Equivalent cost assumption for wind based on fundamental cost structure of the technology (IRP 2019 and cost assumption for this analysis)



USD:ZAR = 14.00; NOTE: Battery packs are assumed to make up 60% of total utility-scale stationary storage costs.
Sources: StatsSA for CPI; IRP 2019; CSIR; NREL ATB; Learning rate – NREL 2019 ATB "Mid"

Figure 26. Equivalent overnight capital cost assumption for stationary storage (IRP 2019 and cost assumption for this scenario)

2.3.8 Supply technologies: New-build constraints

In the IRP 2019, annual new-build constraints are placed on selected technologies. The imposed annual new-build constraints are placed specifically on solar PV and wind technologies (1000 MW/yr and 1600 MW/yr respectively).

The effect of these new-build constraints is that the capacity expansion planning model is not allowed in any given year to add more solar PV and/or wind capacity than the defined maximum. No annual new-build limits are applied for any other technologies.

Figure 27 and Figure 28 show annual new solar PV and wind capacity as well as relative new-build capacity respectively (relative to system peak demand) along with the recent installation of new capacity from the REIPPPP in South Africa. Cumulative installed capacity relative to system peak demand for solar PV and wind is given in Figure 29 and Figure 30 respectively along with the planned deployment of solar PV and wind (from the IRP 2019).

Regardless of economy size or level of development, countries around the world have already been and are continuing with significant deployments of solar PV and wind. For solar PV, leaders like Germany, Spain and Italy deployed significant solar PV capacity since the early 2000s already followed by countries like the United Kingdom, Australia and Japan. From 2010 onwards, other significantly sized deployments have been seen in China and India. For wind, leaders like Germany, Spain and Ireland have been deploying significant amount of wind for almost 2 decades now whilst other countries like China, India and Brazil have more recently started to take a leading role in wind capacity deployment.

As outlined in Section 2.2, the Least-Cost scenario does not impose any new build constraints on any technologies. As demonstrated in Section 3, this can lead to periods of high wind and solar PV new-build followed by multiple years of no new build capacity. Such significant differences in year-on-year new build can be impractical to implement. The Modest and Ambitious RE Industrialisation scenarios in this analysis assume more practical and implementable renewable build programs which attempt to smooth the wind and solar PV annual new build over the planning horizon already part of least-cost outcomes. This was established by enforcing dynamic minimum annual new-build limits on wind and solar PV from 2022 onwards as shown in Figure 31 and Figure 32 for the Modest and Ambitious RE Industrialisation scenarios respectively. These are intended to account for implicit upfront network infrastructure constraints (in early years of the time horizon - specifically for wind) as well as industry capabilities and readiness (localisation ramp-up) but will establish the same renewable energy penetration level by the end of the time horizon with smoothed implementation.

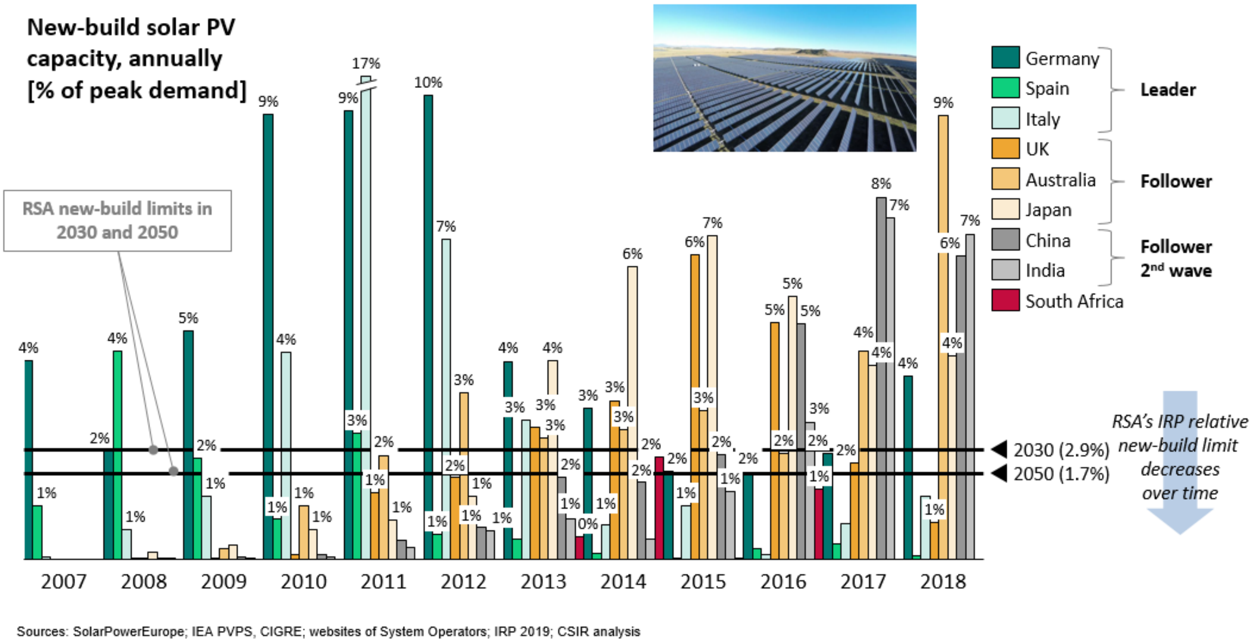


Figure 27. Annual new solar PV capacity relative to system peak demand for a range of countries (including leaders, followers and 2nd wave followers) along with the IRP 2019 annual new-build capacity.

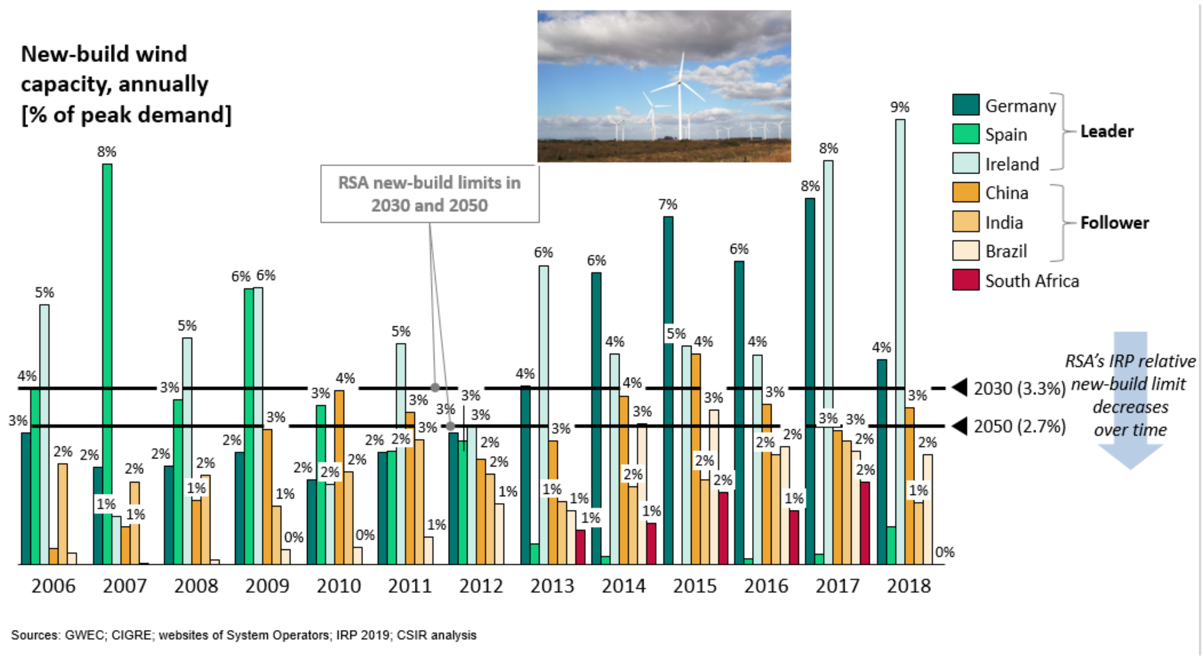


Figure 28. Annual new wind capacity relative to system peak demand for a range of countries (including leaders and followers) along with the IRP 2019 annual new-build capacity.

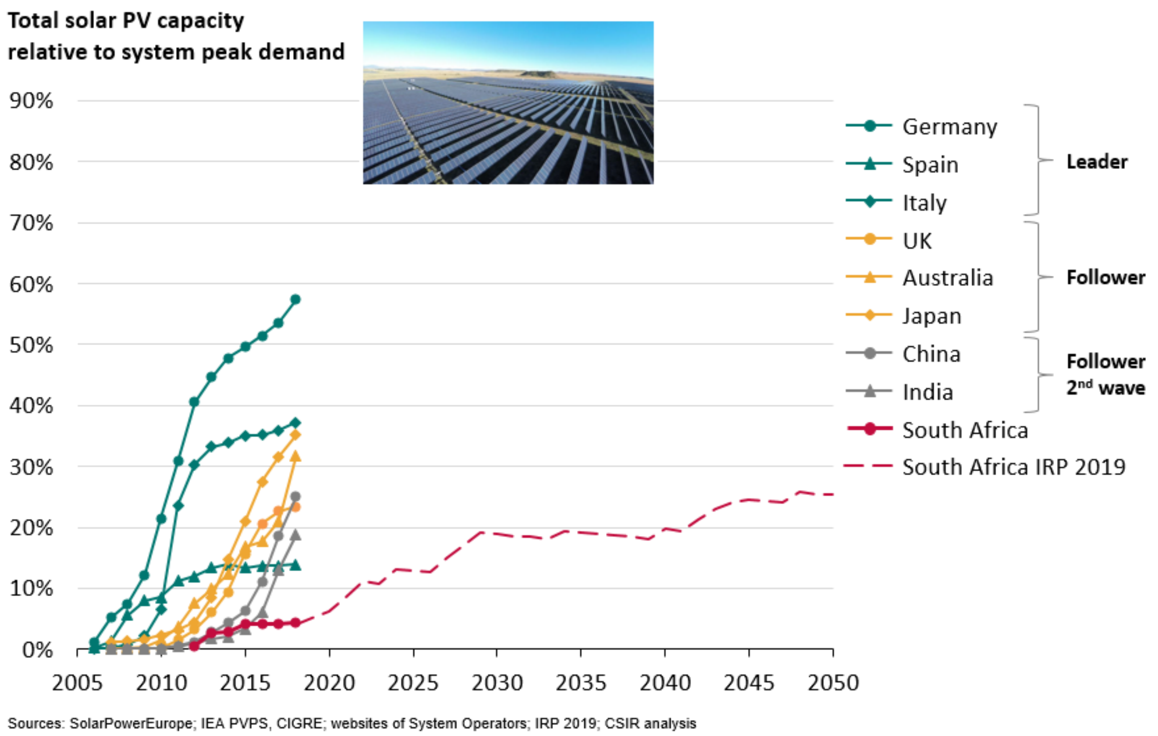


Figure 29. Cumulative solar PV capacity relative to system peak demand (including leaders, followers and 2nd wave followers) along with the IRP 2019 cumulative capacity.

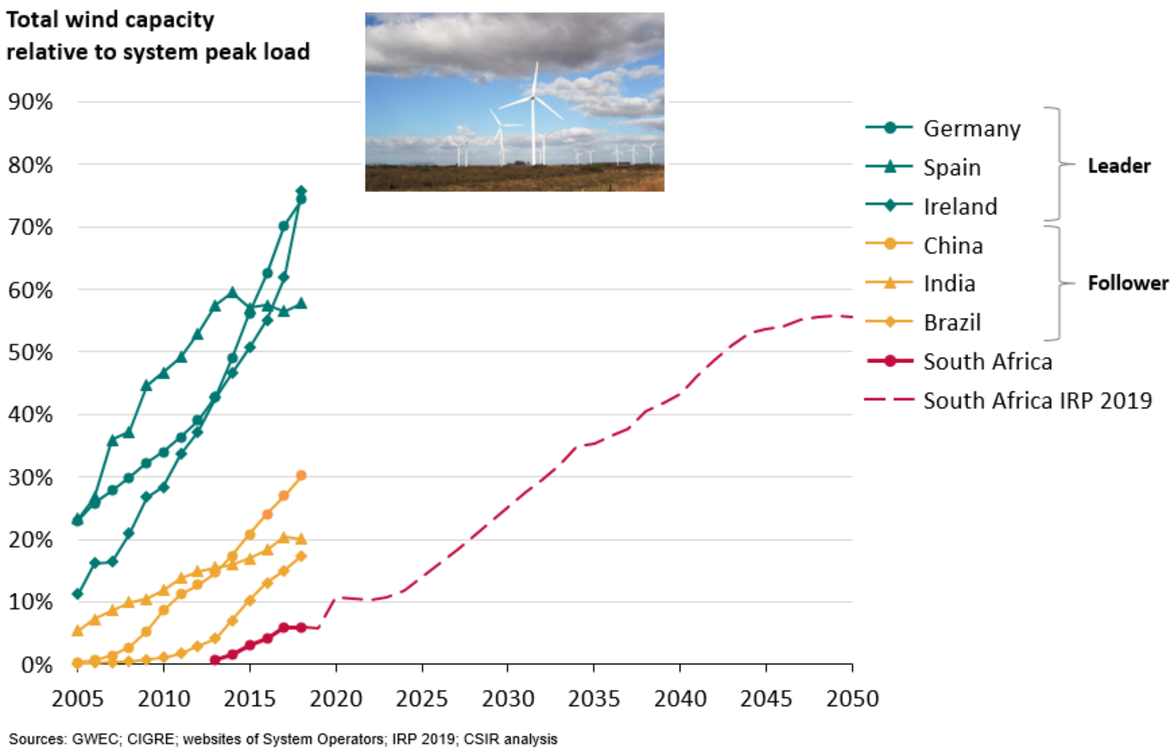


Figure 30. Cumulative wind capacity relative to system peak demand (including leaders and followers) along with the IRP 2019 cumulative capacity.

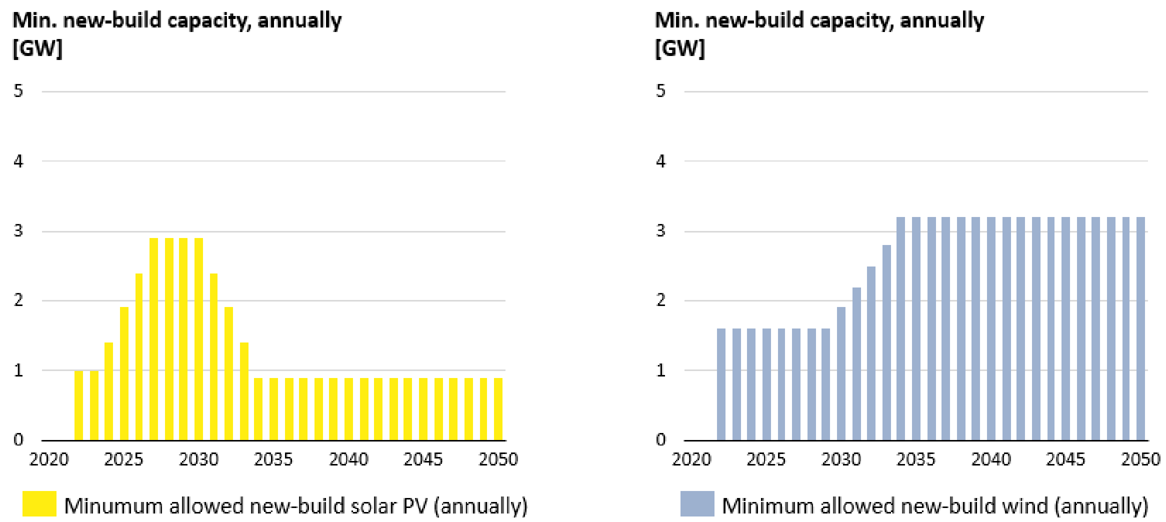


Figure 31. Minimum annual new build constraints for solar PV and wind in the Modest RE Industrialisation scenario

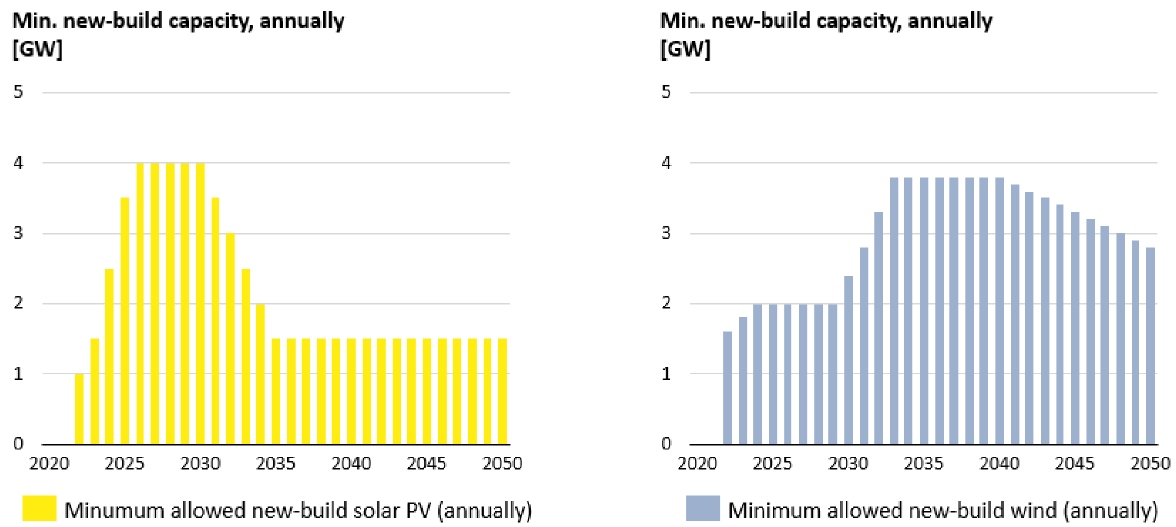


Figure 32. Minimum annual new build constraints for solar PV and wind in the Ambitious RE Industrialisation scenario

2.3.9 Electricity sector emissions

Emission rates for CO_2, SOx, NOx, and particulate matter (PM) for all technologies are aligned with those included in the 2017 EPRI report as utilized in the IRP 2019 [35].

The electricity sector CO_2 emissions constraint included in the IRP 2019 is shown in Figure 33. This is driven by South Africa's National Climate Change Response White Paper [36] which defines a Peak-Plateau-Decline (PPD) trajectory for Greenhouse Gas (GHG) emissions as part of the mitigation strategy for South Africa. The PPD Moderate trajectory shown in Figure 33 is taken from the IRP 2019. This has been formalised into South Africa's Intended Nationally Determined Contribution (INDC) and then Nationally Determined Contribution (NDC) following the commitments as part of the United Nations Framework Convention on Climate Change (UNFCCC) Paris Agreement [37].

In this analysis, the PPD trajectory was used for the IRP 2019 and Reference scenarios. No CO_2 constraint was enforced in the Least-cost scenario. The expected range of CO_2 emissions for the period of 2020-2050 is expected to be 2.0-3.0 Gt. In the 2Gt CO_2 budget Scenario, a total CO_2 budget constraint of 2.0 Gt was applied for the period 2020 – 2050.

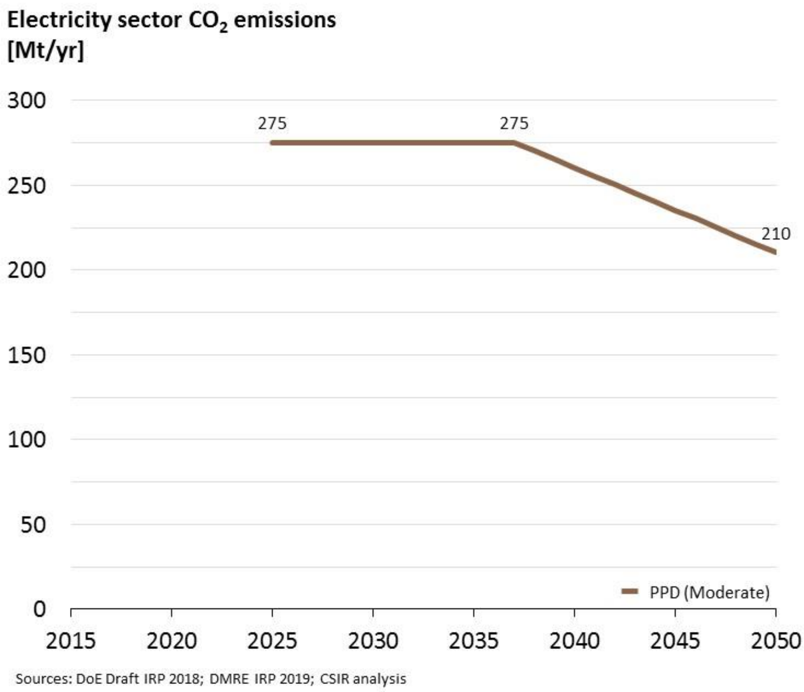


Figure 33. Electricity sector CO_2 emissions trajectory used in the IRP 2019 (PPD trajectory).

2.3.10 Economic parameters

Relevant general economic input parameters are aligned with that of the IRP 2019. These can be summarized as an after-tax real discount rate of 8.2%, which is equal to the economic opportunity cost of capital (EOCK) specified by National Treasury.

A cost of unserved energy (COUE) of R87.85/kWh (January 2017 Rands) as utilized in the IRP 2019 is escalated to January 2019 Rands and used for all scenarios [6]. COUE refers to the opportunity cost to electricity consumers (and the economy) of electricity supply interruptions and is utilized for long-term energy planning purposes as part of the least-cost objective function to balance investment in new capacity and utilization of existing capacity. The inclusion of COUE, operating reserve requirements and a minimum reserve margin, ensures that an acceptable level of system adequacy is achieved. This is as a result of the natural balance achieved via the optimisation where the high cost of unserved energy is avoided by building additional capacity and dispatching existing capacity optimally to meet expected demand.

3 Scenario results

3.1 IRP 2019 (DMRE)

In this scenario the CSIR simulated the IRP 2019 [6] by developing a representative electricity capacity expansion model of the South African power system using the IRP 2019 input assumptions.

As part of this, the scenario deploys all capacity in the IRP 2019 up until 2030 (as per current policy) where after least-cost capacity expansion is allowed up to 2050 (aligned with IRP 2019 input assumptions).

This scenario is defined by the following input assumptions:

IRP 2019 (DMRE)	
Demand Forecast	*IRP 2019 Median*
Carbon emission constraint	*Peak-Plateau-Decline (PPD)*
Existing fleet performance	*IRP 2019 (75.5% by 2025)*
Existing coal fleet decommissioning	*50-year life*
Short-term emergency options[5]	*Included*
Forced in new build technologies	*As per Table 5, IRP 2019* [6] *up to 2030*
Wind/solar PV annual new build constraints	*Wind: 1600 MW/yr; Solar PV: 1000 MW/yr*
New technology costs:	*IRP 2019*

The capacity and energy contribution per technology type for the IRP 2019 scenario is shown in Figure 34 for the full study horizon (to 2050).

The first new build capacity (beyond the short-term emergency options) occurs in 2022 and consists of 1.6 GW of wind, 1.0 GW of solar PV and 0.5 GW of stationary storage. New coal capacity (0.75 GW) is planned for 2023 (and another 0.75 GW by 2027) as per the DMRE's policy adjustment process, followed by 1.0 GW of new gas capacity in 2024 (and further additional gas capacity from 2027 onwards). The imported hydro-based electricity in 2030 is the policy-adjusted 2.5 GW Inga from the Democratic Republic of Congo (DRC). No new-build nuclear or CSP capacity is built in this scenario.

The combination of increased power system size (growing demand) and decommissioning existing coal capacity, results in the solar PV and wind new build constraints becoming binding and forcing a choice of other technologies that would not otherwise be part of a least-cost outcome. Thus, by 2037,

[5] Includes immediate customer response at scale (mostly embedded/distributed solar PV, storage) and other short-term risk mitigation capacity to ensure adequacy gap is met (portfolio of technologies/options)

new coal capacity is built (amongst other new-build capacity) as depicted in Figure 35. Thus, 22.2 GW of coal capacity is online by 2050 consisting of the existing and currently under construction capacity (9.9GW) and 12.3 GW of new-build coal capacity.

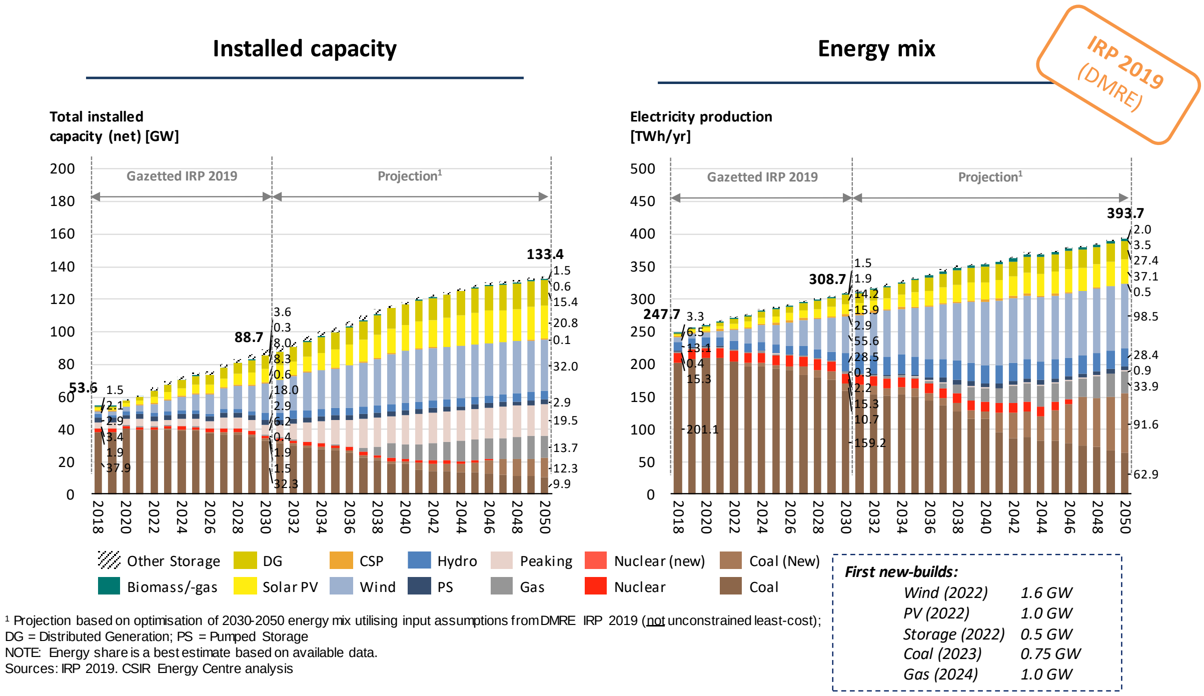
A relatively small amount of gas-fired capacity is built pre-2030 (3.9 GW of OCGTs/GEs) whilst a seemingly considerable amount of gas-fired capacity is built by 2050 (28.4 GW in total comprised of 6.0 GW CCGT/GEs and 21.7 GW OCGT/GEs). However, it is important to appreciate that the use of this capacity results in only a 5.0% contribution of natural gas to the energy mix by 2050. Thus, a fleet capacity factor of ≈28% for CCGT/GEs and ≈2% for OCGT/GEs by the end of the time horizon.

Stationary storage is also deployed in the IRP 2019 pre-2030 whereby 0.51 GW is deployed in 2022 and an additional 1.59 GW in 2029. This is assumed to be 3-hour Li-Ion storage. Post 2030, no additional stationary storage capacity is deployed in this scenario.

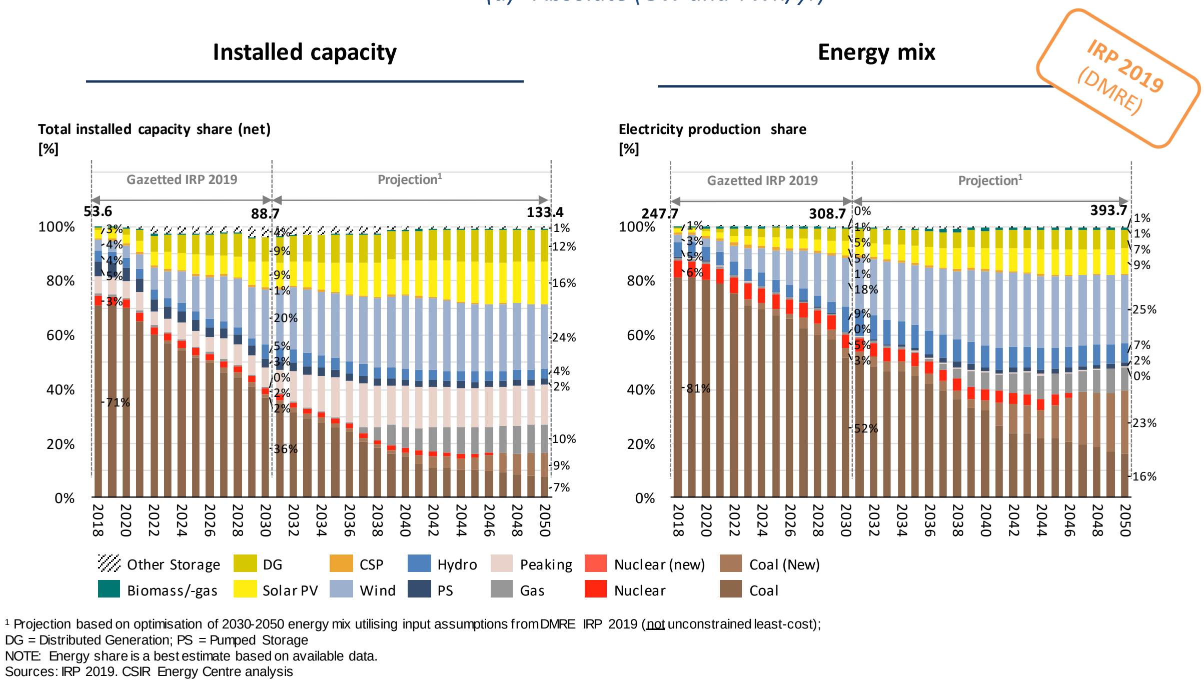
Electricity sector CO_2 emissions, water usage, SOx, NOx and particulate matter (PM) resulting from the IRP 2019 scenario are shown in Figure 36 - Figure 38. Initially, all electricity sector emissions decline as the existing coal fleet is decommissioned. The increase in CO_2 emissions during the last decade of the planning horizon is due to new coal capacity being built in response to the constraints on new build wind and solar PV. A total of 5.2 Gt of electricity CO_2 emissions are produced over the 2020 – 2050 horizon (relative to the equivalent carbon budget from the PPD (Moderate) constraint of 6.7 Gt).

Water usage is expected to drop significantly in this scenario even as new-build coal capacity is built. This trend is expected as a result of new-build coal capacity being assumed to be dry-cooled. Similarly, SOx emissions continue to decline as a result of any new-build coal capacity being assumed to include flue gas desulphurization (FGD).

The equivalent average wholesale electricity tariff for this scenario is shown in Figure 39 (in Real terms). The expectation for the equivalent wholesale tariff is for an increase from the 0.87 R/kWh to 1.05 R/kWh by 2030 and 1.22 R/kWh by 2050 (all in January-2019 Rands).

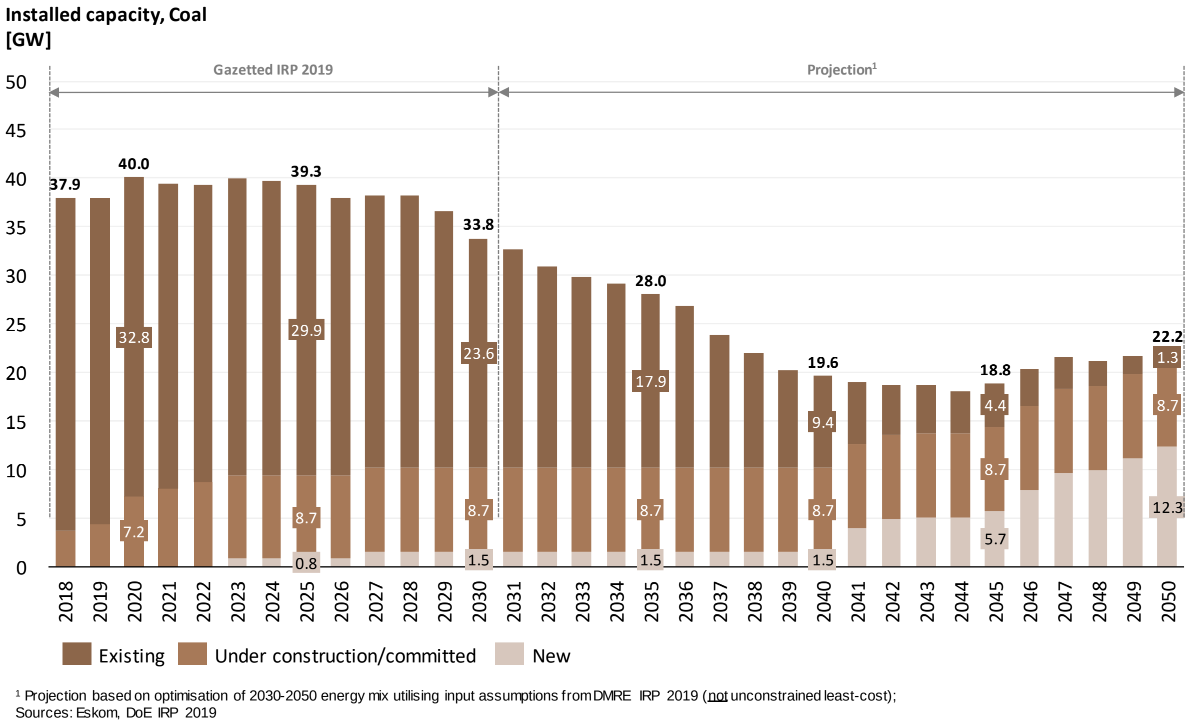


(a) Absolute (GW and TWh/yr)

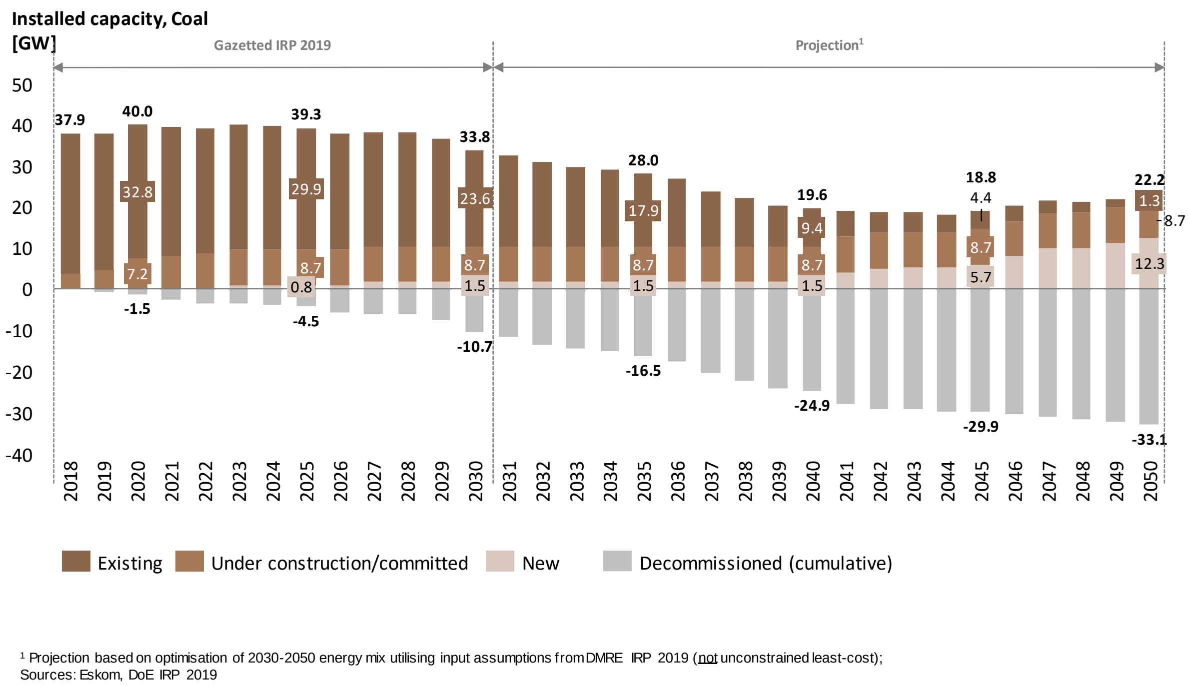


(b) Share (%)

Figure 34. Installed capacity and energy mix for IRP 2019 from 2018-2030, extended to 2050 by CSIR



(a) Existing, under construction and new coal capacity from IRP 2019



(b) Existing, under construction and new coal capacity from IRP 2019 combined with cumulative decommissioned coal capacity

Figure 35. Coal capacity from IRP 2019 to 2030 (extended to 2050 by CSIR)

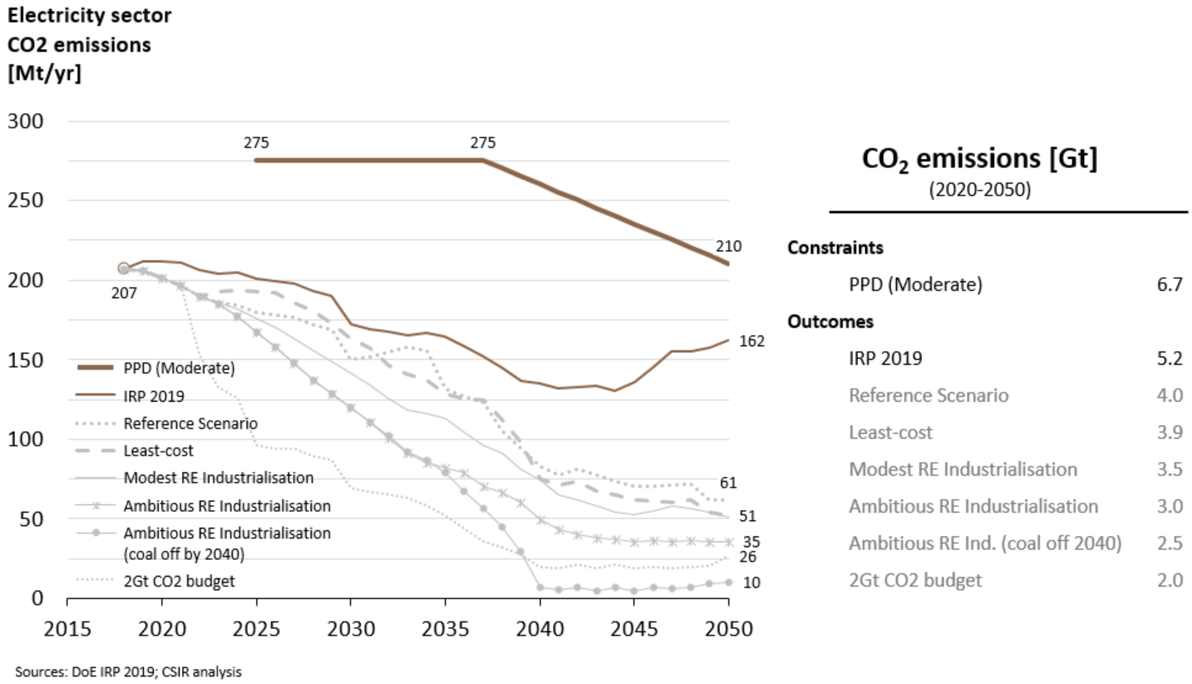


Figure 36: Electricity sector CO_2 emission for the IRP 2019 from 2018-2030, extended to 2050 by the CSIR

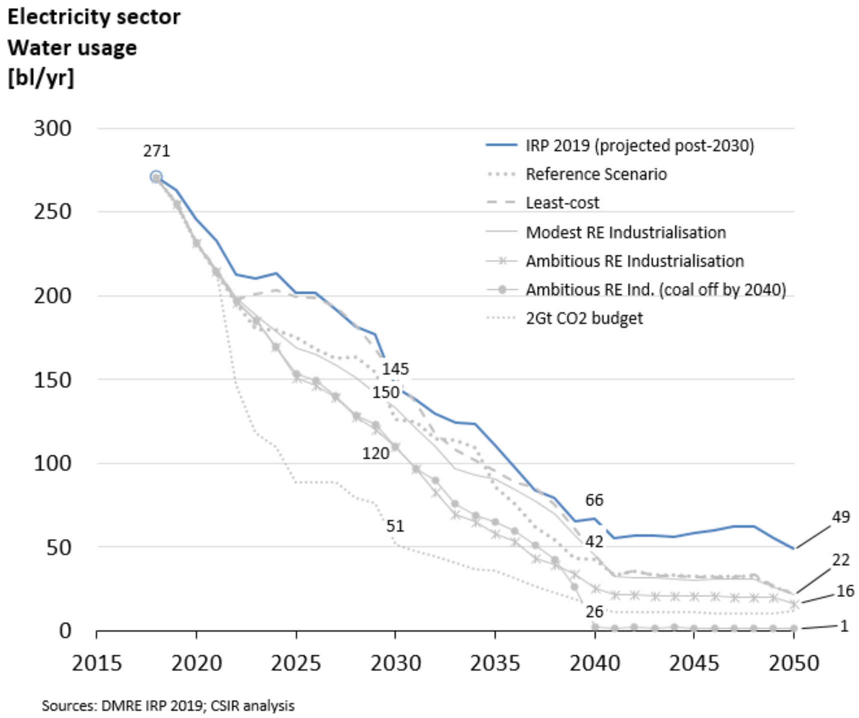


Figure 37. Electricity sector water usage for the IRP 2019 from 2018-2030, extended to 2050 by the CSIR

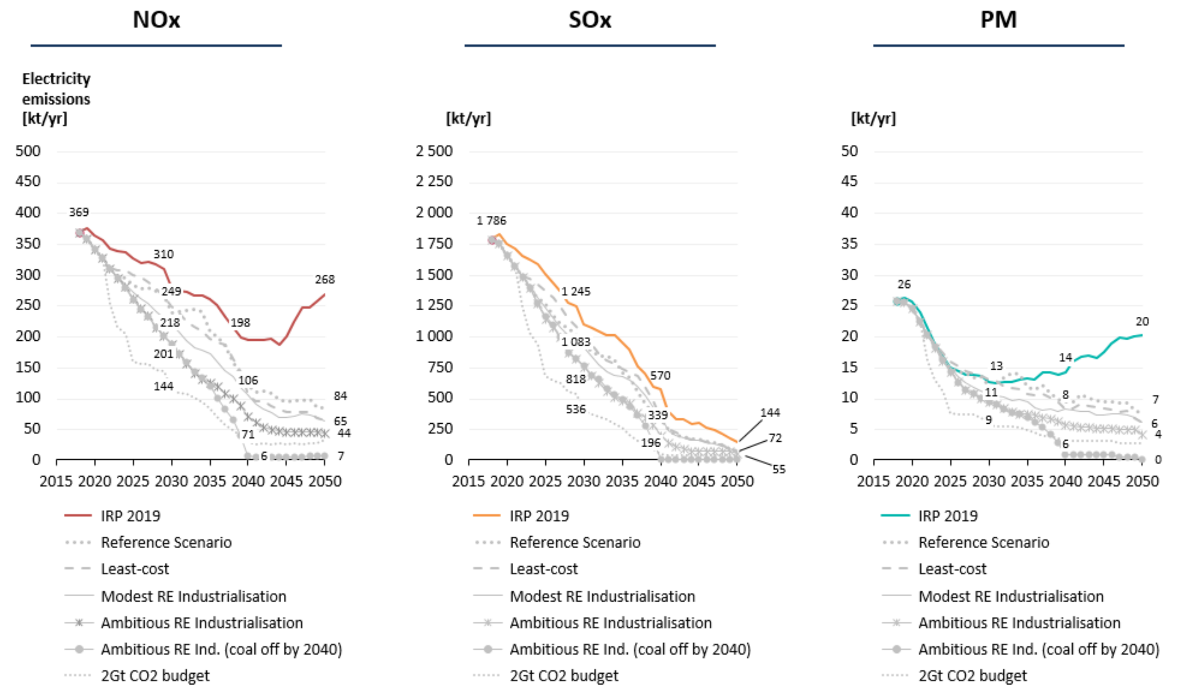
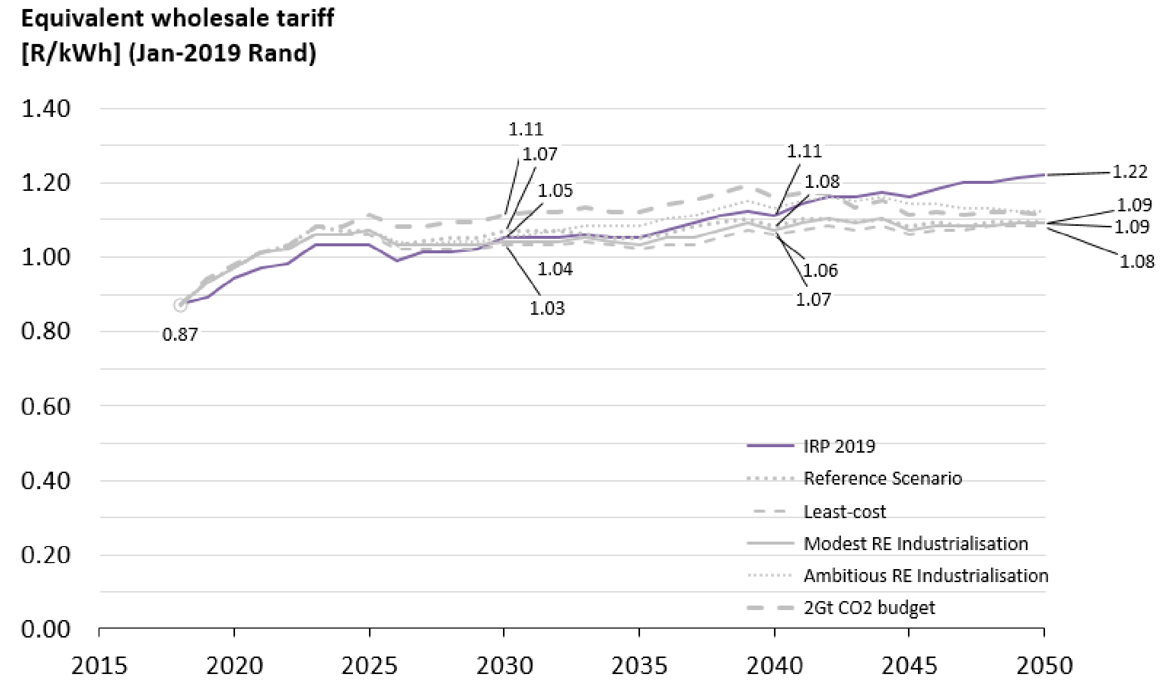


Figure 38. Electricity sector NOx, SOx and PM for the IRP 2019 from 2018-2030, extended to 2050 by the CSIR



Notes: Transmission (Tx), distribution (Dx), system services (often referred to as ancillary services) and other costs not explicitly included in the PLEXOS modelling framework are approximated by a high level assumption of 0.20 R/kWh for all of these cost components consistently across all scenarios.
Sources: CSIR Energy Centre analysis

Figure 39. Equivalent average tariff for the IRP 2019 (2018-2030, extended to 2050 by CSIR)

3.2 Reference (Current Policy)

In order to compare the costs of future alternative energy supply scenarios against a reference scenario, the technology costs and demand forecast assumptions should be aligned between all scenarios. The IRP 2019 could thus not be used for comparison to other scenarios and the Reference scenario was created. Changes include more recent technology cost assumptions aligned with the latest available information, the demand forecast and existing fleet EAF whilst annual new-build constraints on wind and solar PV removed from 2031 onwards.

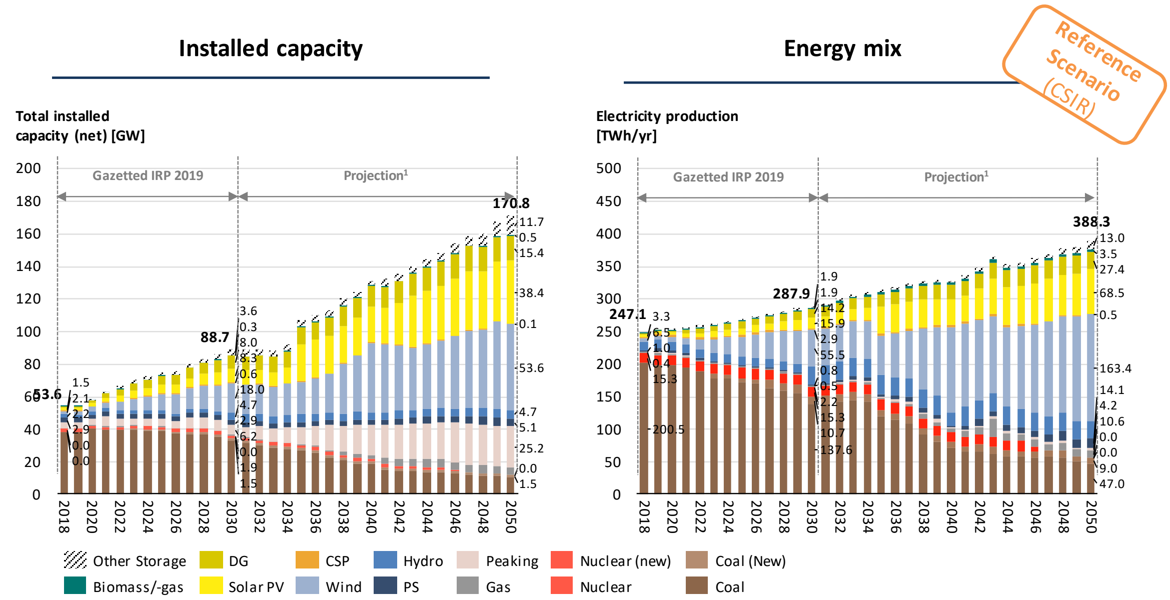
This scenario is defined by the following input assumptions:

Reference scenario	
Demand Forecast	*Updated demand (CSIR) (see Figure 13)*
Carbon emission constraint	*Peak-Plateau-Decline (PPD)*
Existing fleet performance	*Updated EAF (CSIR) (see Figure 18)*
Existing coal fleet decommissioning	*50-year life*
Short-term emergency options[6]	*Included*
Forced in new build technologies	*As per Table 5, IRP 2019* [6] *up to 2030*
Wind/solar PV annual new build constraints	*As in IRP 2019 to 2030, none after 2030*
New technology costs:	*Updated technology costs (CSIR)*

The capacity and energy contribution per technology type for the Reference Scenario is shown in Figure 40 for the full study horizon. As in the IRP 2019 scenario, the first new build capacity is aligned with current policy to 2030. It can be seen that the least-cost new build mix beyond 2030 consists of solar PV, wind, storage and natural gas-fired capacity, with no further coal capacity being built (also depicted further in Figure 41). This is as a direct result of removing the annual wind and solar PV new build constraints post 2030 that were imposed in the IRP 2019. New-build storage capacity is dominated by short duration battery storage and only late in the time horizon is additional pumped storage built (with 2.2 GW by 2050). No new-build nuclear or CSP capacity is built in this scenario. There is a visible slow-down in the pace of new build capacity (of any technology) for the period 2030-2034. This is a result of the policy adjusted IRP 2019 capacity (based on a higher demand forecast) being forced in prior to 2030 with a lower demand forecast.

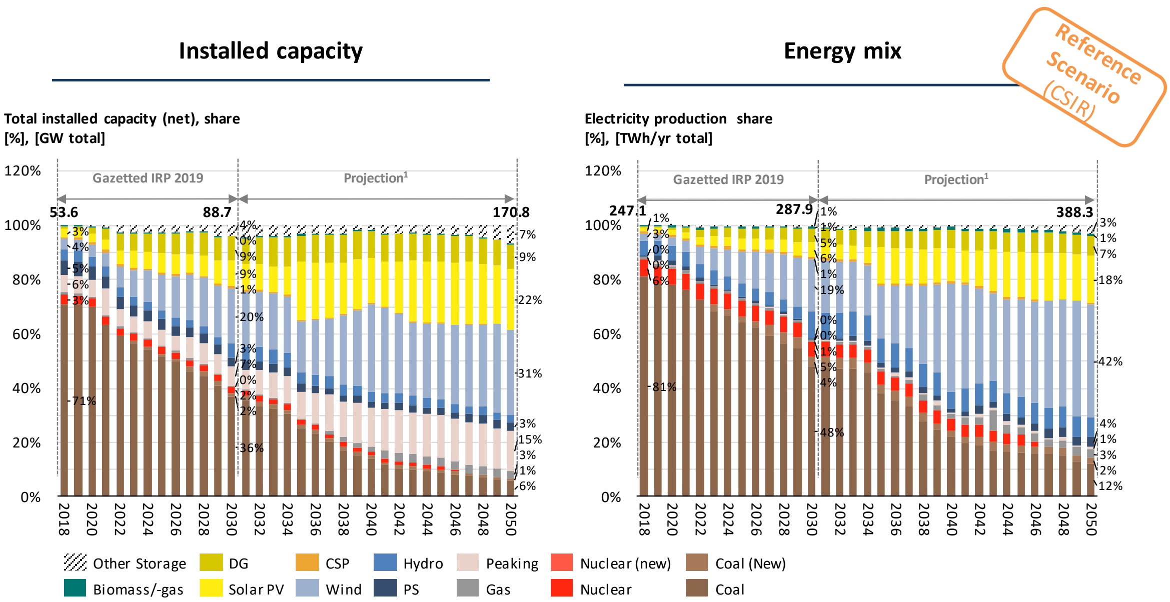
[6] Includes immediate customer response at scale (mostly embedded/distributed solar PV, storage) and other short-term risk mitigation capacity to ensure adequacy gap is met (portfolio of technologies/options)

As with the IRP 2019 scenario, the existing coal fleet was assumed to remain online until the end of their 50-year life and no early coal fleet decommissioning. By the end of the planning horizon (by 2050), 11.4 GW of coal capacity comprising two units at Majuba, the currently under construction Medupi and Kusile capacity as well as the forced-in 1.5 GW of new-build coal capacity from the IRP 2019 is still operational.



¹ Projection based on optimisation of 2030-2050 energy mix utilising CSIR input assumptions from CSIR;
DG = Distributed Generation; PS = Pumped Storage
Sources: IRP 2019. CSIR Energy Centre analysis

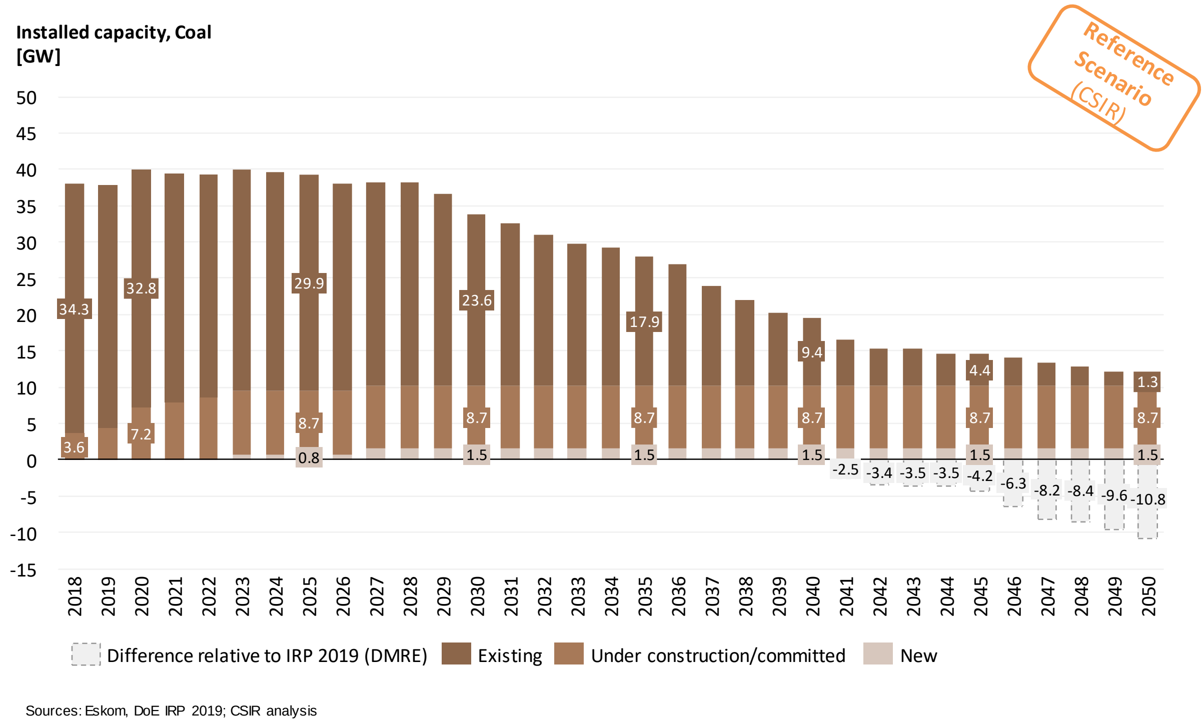
(a) Absolute (GW and TWh/yr)



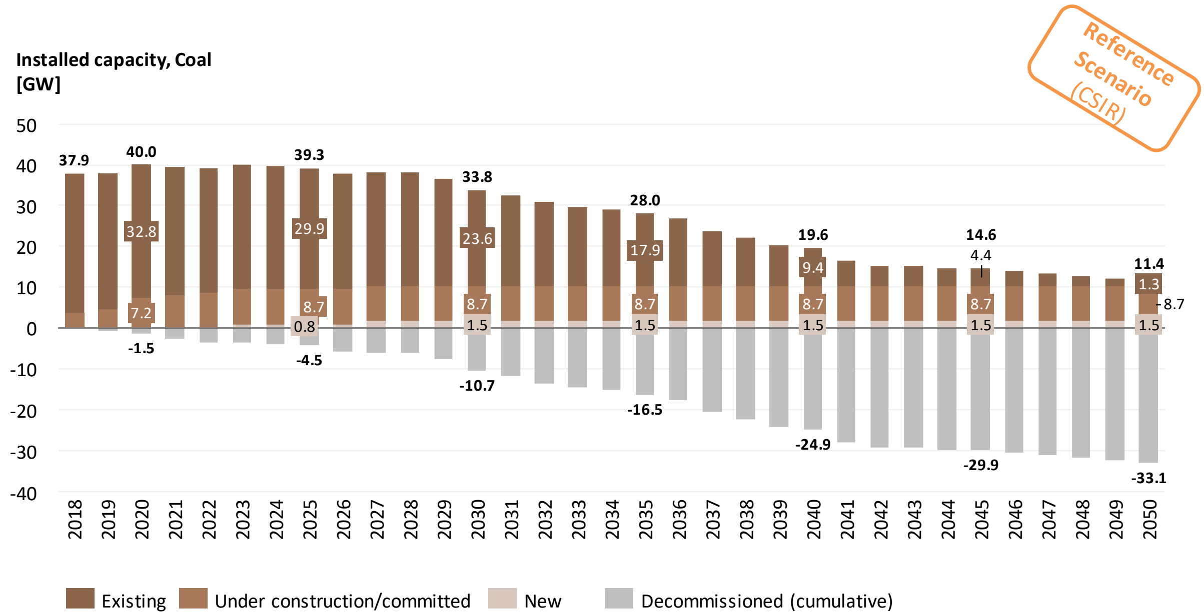
¹ Projection based on optimisation of 2030-2050 energy mix utilising input assumptions from CSIR;
DG = Distributed Generation; PS = Pumped Storage
Sources: IRP 2019. CSIR Energy Centre analysis

(b) Share (%)

Figure 40. Installed capacity and energy mix for the Reference Scenario from 2018-2050



(a) Existing, under construction and new coal capacity from Reference scenario



(b) Existing, under construction and new coal capacity from Reference scenario combined with cumulative decommissioned coal capacity

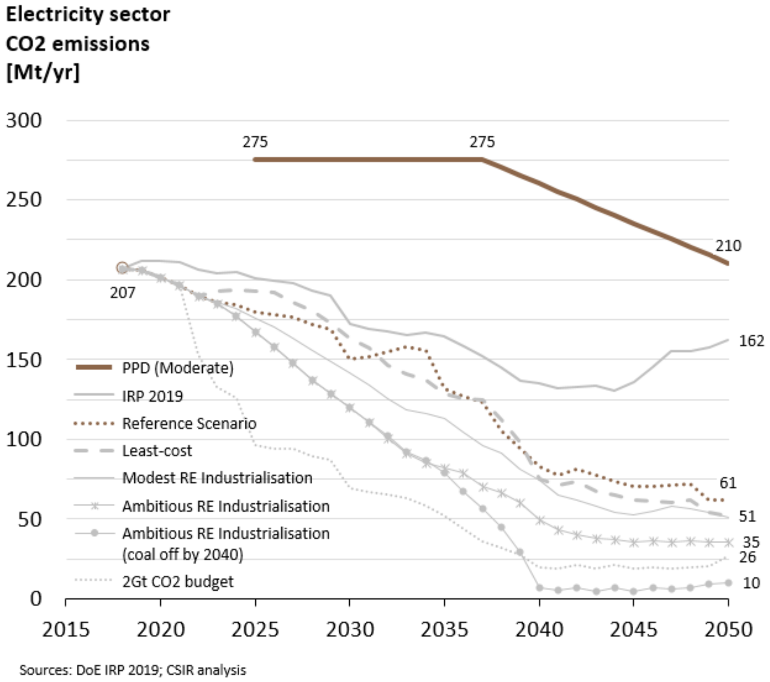
Figure 41. Existing, under construction and new coal capacity in the Reference Scenario

The electricity sector CO_2 emissions, water usage, SOx, NOx and particulate matter (PM) resulting from this scenario are shown in Figure 42 - Figure 44. A similar trend for CO_2 emissions to the IRP 2019 scenario can be observed up to 2030, with overall lower emissions due the lower demand forecast and lower EAF expectation. A drastic reduction can be observed beyond 2035 as the existing coal fleets decommissions and is replaced by renewable energy in the energy mix. A total of ≈4 Gt of electricity sector CO_2 emissions are produced over the horizon (2020-2050).

Water usage is also shifted notably lower as a result of lower demand forecast and EAF. However, the trend is similar to that of the IRP 2019 as a result of new-build coal capacity built being assumed to be dry-cooled as coal generation is the dominant driver of water usage. SOx emissions are also lower as new-build coal capacity is assumed to include FGD.

The notable deviation in emissions between the Reference scenario and IRP 2019 is on NOx and PM where the Reference scenario shows a significantly lower post 2030 trajectory for both NO_X and PM. This is expected as a result of no new-build coal capacity post 2030 as the new-build constraints on solar PV and wind are removed in this scenario.

The equivalent average wholesale electricity tariff for this scenario is shown in Figure 45. The expectation for the equivalent wholesale tariff is initially higher than the IRP 2019 as a result of the pre 2030 IRP 2019 capacity investments made even though demand is lower, as well as the poorer EAF assumption. This quickly changes post 2030 as the equivalent tariff shifts below the IRP 2019 scenario to end at 1.09 R/kWh by 2050.



CO_2 emissions [Gt]
(2020-2050)

Constraints	
PPD (Moderate)	6.7
Outcomes	
IRP 2019	5.2
Reference Scenario	4.0
Least-cost	3.9
Modest RE Industrialisation	3.5
Ambitious RE Industrialisation	3.0
Ambitious RE Ind. (coal off 2040)	2.5
2Gt CO2 budget	2.0

Figure 42. Electricity sector CO_2 emission for the Reference Scenario

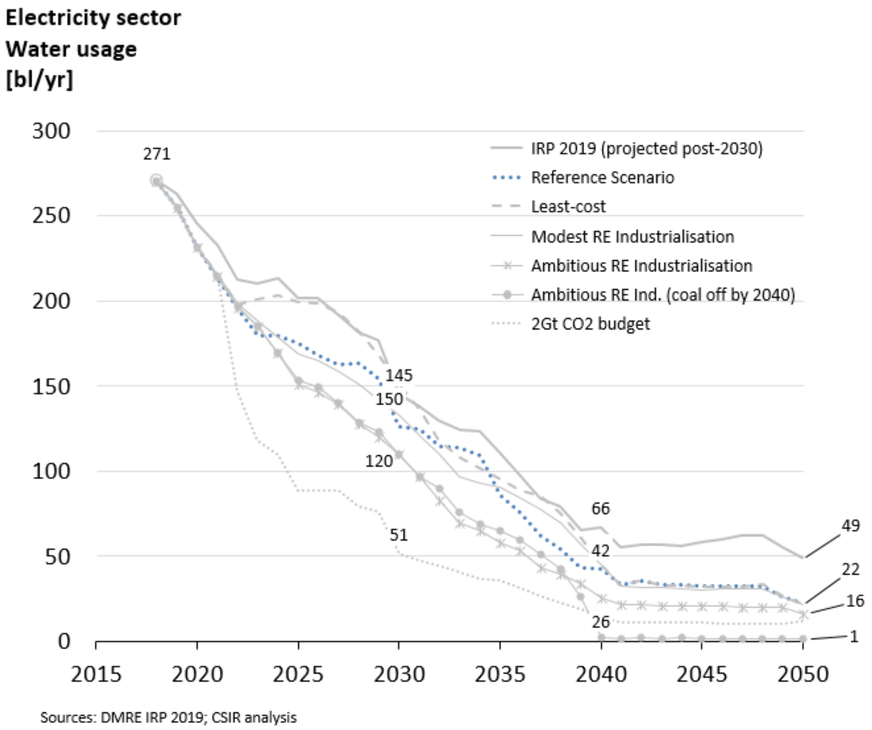


Figure 43. Electricity sector water usage for the Reference Scenario

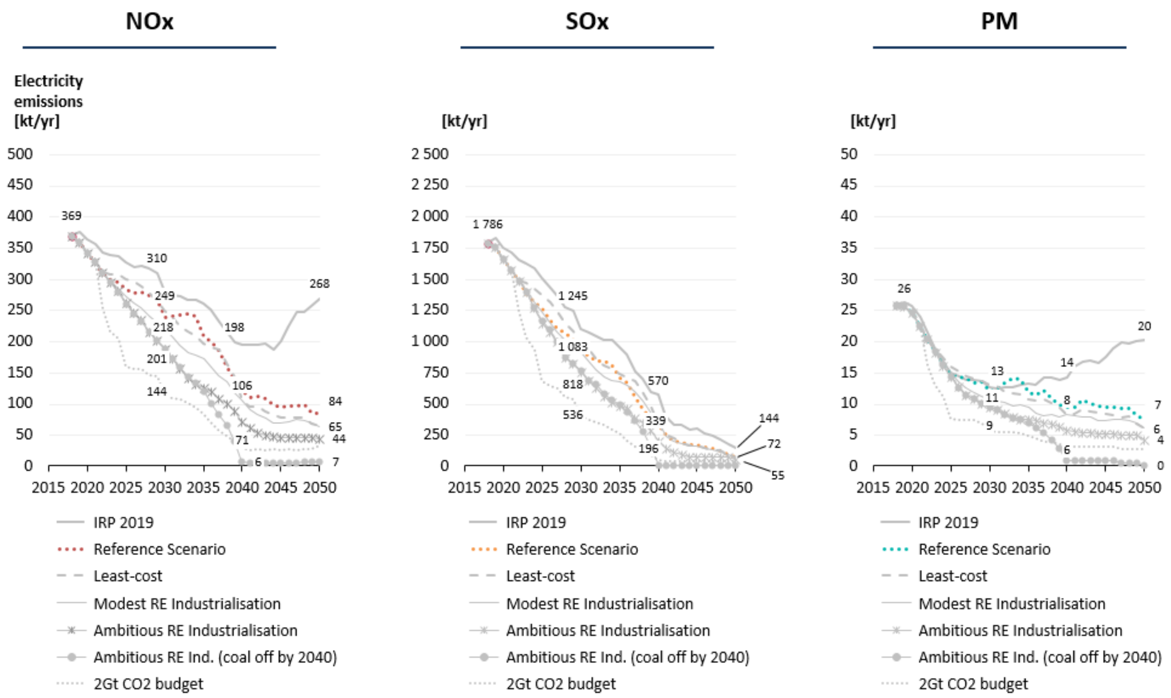
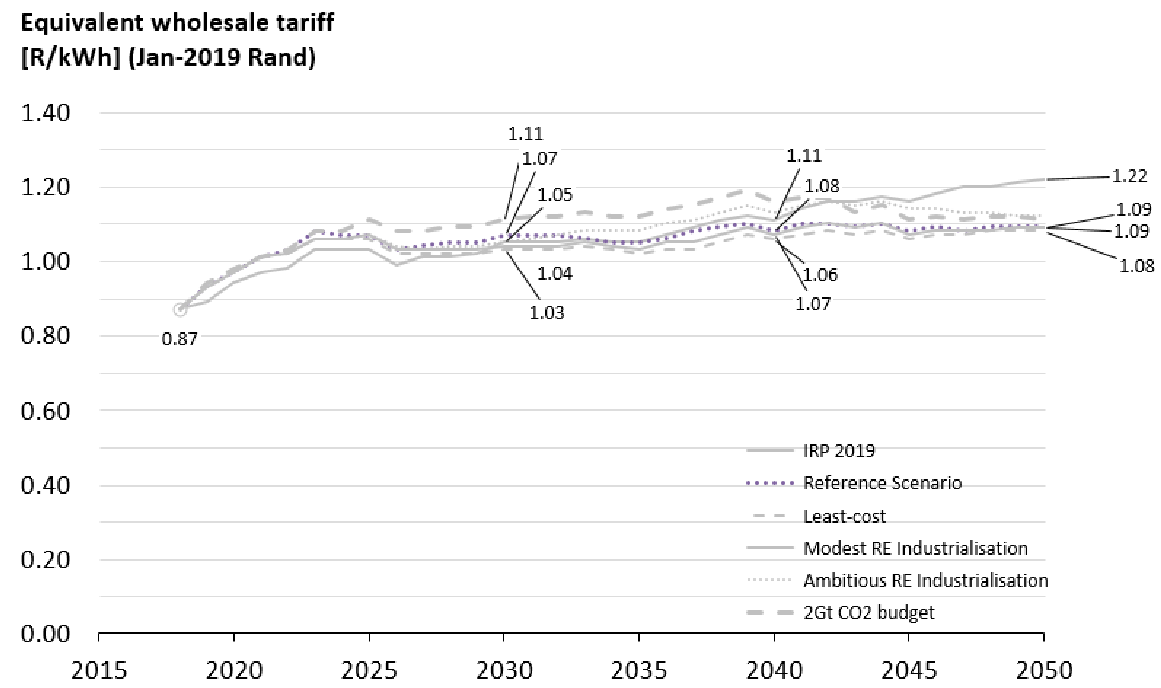


Figure 44. Electricity sector NOx, SOx and PM for the Reference Scenario



Notes: Transmission (Tx), distribution (Dx), system services (often referred to as ancillary services) and other costs not explicitly included in the PLEXOS modelling framework are approximated by a high level assumption of 0.20 R/kWh for all of these cost components consistently across all scenarios.
Sources: CSIR Energy Centre analysis

Figure 45. Equivalent average tariff for Reference scenario

3.3 Least-Cost

A completely unconstrained least-cost scenario is the cornerstone of the IRP in South Africa as it establishes the basis upon which scenarios can be compared. This is also further described in section 2.1 and in [38], [39] for the interested reader.

Thus, this scenario is similar to the Reference scenario but with no carbon emissions constraint, no forced-in new-build technologies and no annual new-build constraints on any technologies.

This scenario is defined by the following input assumptions:

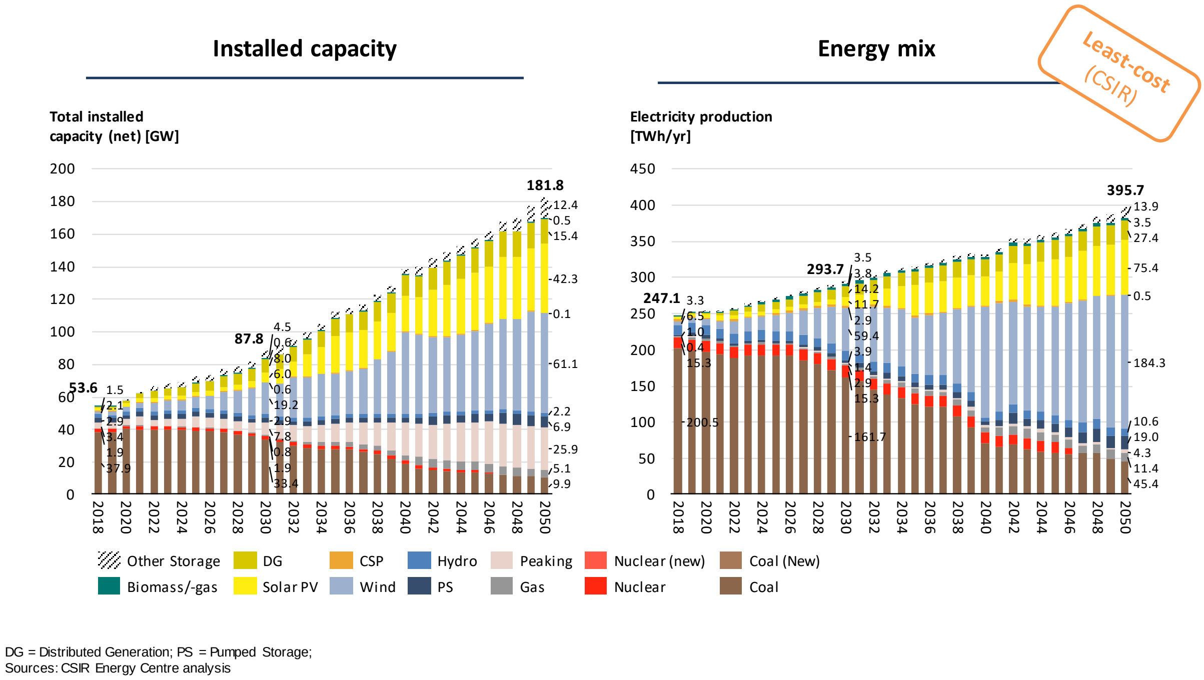
Least-Cost	
Demand Forecast	*Updated demand (CSIR) (see Figure 13)*
Carbon emission constraint	*None*
Existing fleet performance	*Updated EAF (CSIR) (see Figure 18)*
Existing coal fleet decommissioning	*Endogenous decommissioning*
Short-term emergency options[7]	*Included*
Forced in new build technologies	*None*
Wind/solar PV annual new build constraints	*None*
New technology costs:	*Updated technology costs (CSIR)*

The capacity and energy contribution per technology type for the Least-cost scenario is shown in Figure 46 for the full study horizon. The least-cost new build mix consists of solar PV, wind, storage and natural gas fired capacity supported by an existing fleet of generation capacity including coal, nuclear and imports. The Least-cost energy mix is 41% carbon-free (36% renewables) by 2030 and 76% carbon-free (76% renewables) by 2050. Similar to the Reference scenario, short duration battery storage is deployed and supplemented by additional pumped storage capacity starting to deploy after 2035 but with more capacity in this scenario relative to the Reference scenario by 2050 (3.4 GW). No new-build nuclear, coal or CSP capacity is built in this scenario.

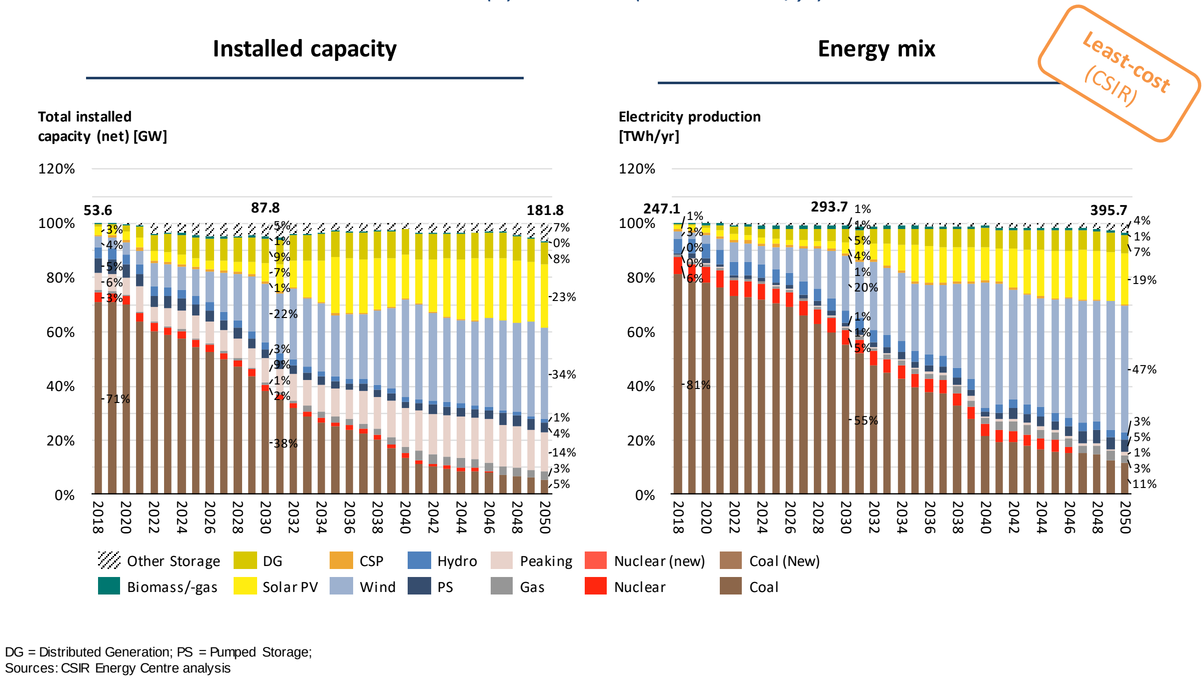
With this scenario exploring endogenous coal fleet decommissioning (before 50-year life), no earlier than expected decommissioning of the coal fleet is expected. By the end of the planning horizon, 9.9 GW of coal capacity comprising two units at Majuba and the under construction Medupi and Kusile capacity is still operational.

[7] Includes immediate customer response at scale (mostly embedded/distributed solar PV, storage) and other short-term risk mitigation capacity to ensure adequacy gap is met (portfolio of technologies/options)

The imported hydro electricity from Inga is also not part of the least-cost energy mix and is instead replaced with wind, solar PV, storage and gas-fired capacity.

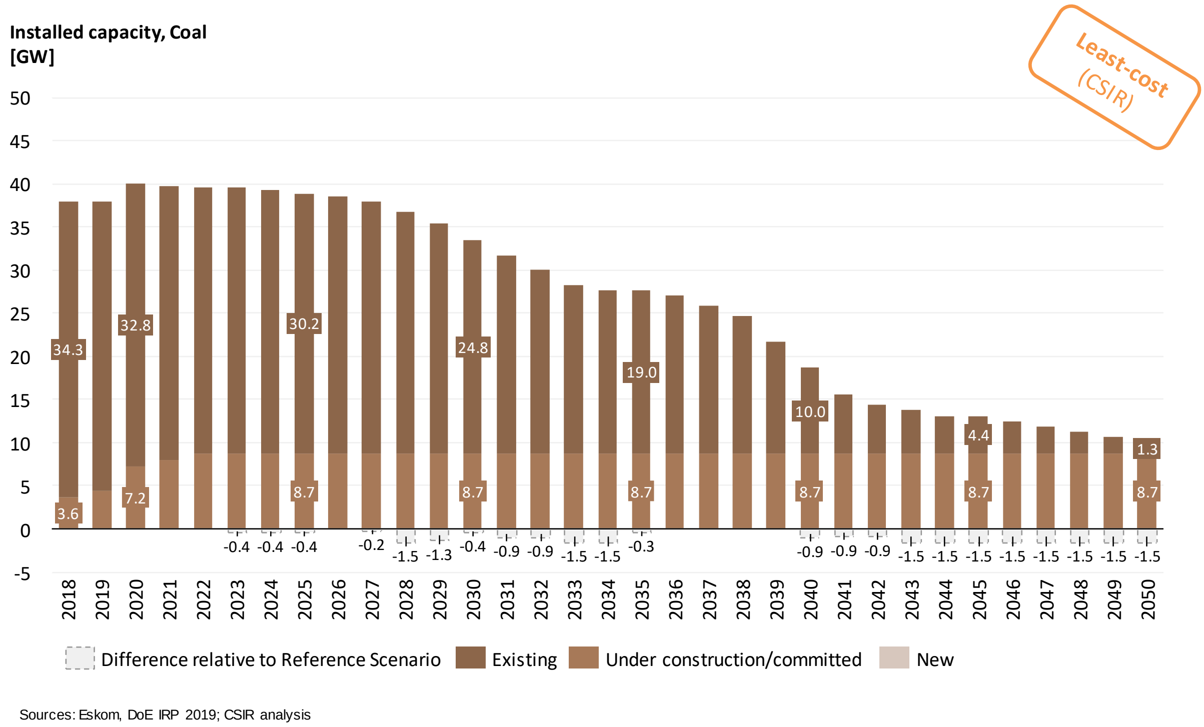


(a) Absolute (GW and TWh/yr)

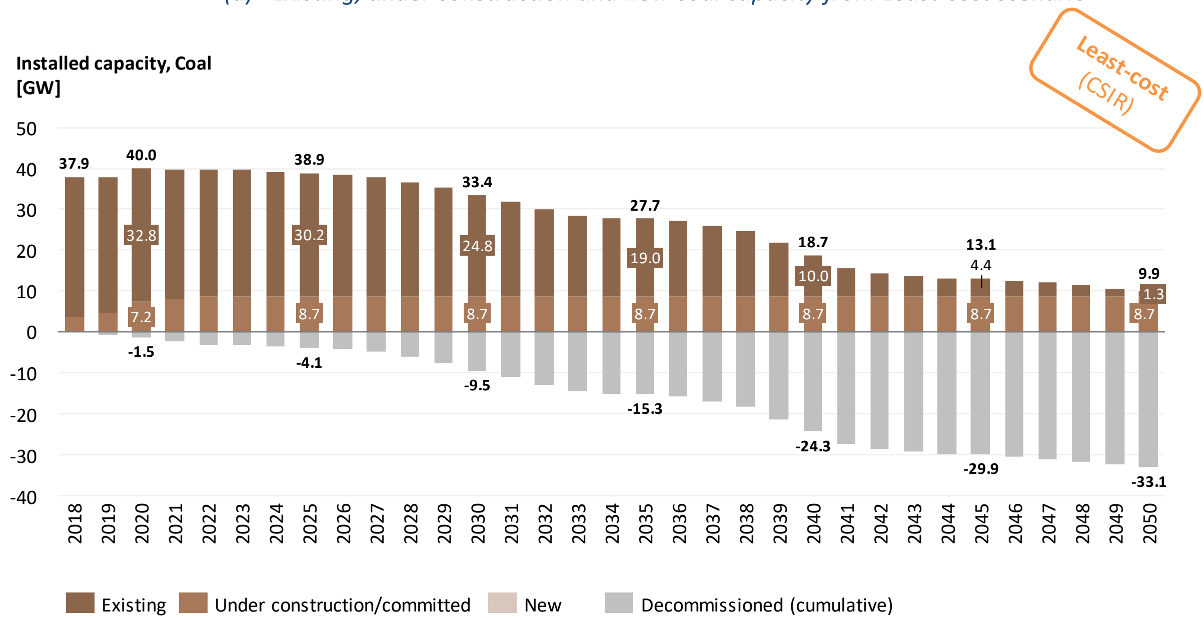


(b) Share (%)

Figure 46. Installed capacity and energy mix for the Least-Cost scenario from 2018-2050



(a) Existing, under construction and new coal capacity from Least-cost scenario



(b) Existing, under construction and new coal capacity from Least-cost scenario combined with cumulative decommissioned coal capacity

Figure 47. Existing, under construction and new coal capacity in the Least-Cost Scenario

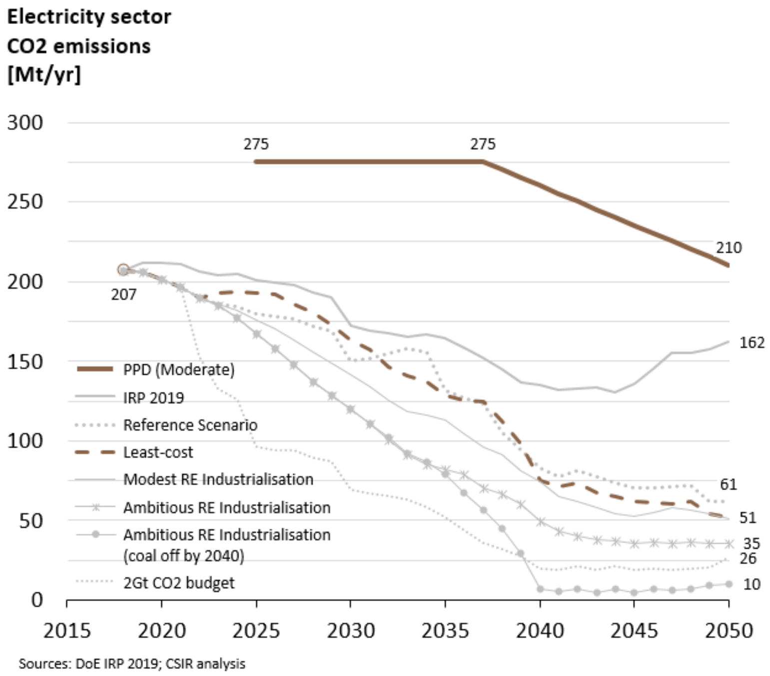
The electricity sector CO_2 emissions, water usage, SOx, NOx and particulate matter (PM) resulting from this scenario are shown in Figure 48 - Figure 50. A similar trend to the IRP 2019 scenario can be observed up to 2030 on CO_2 emissions, with overall lower emissions due the lower demand forecast and lower EAF expectation relative to the IRP 2019. Similar to the Reference scenario, a continued reduction in CO_2 emissions can be observed beyond 2035 as the share of renewable energy in the energy mix increases. A total of ≈3.9 Gt of electricity sector CO_2 emissions are produced over the horizon (2020-2050).

Water usage is similar to the Reference scenario (as expected) but shifted notably lower relative to the IRP 2019 as a result of the lower demand forecast and EAF. However, the downward trend is similar as a result of new-build coal capacity built in the IRP 2019 being assumed to be dry-cooled.

SOx emissions are also lower than the IRP 2019 scenario for similar reasons but with a similar trend downwards as new-build coal capacity is assumed to include flue-gas desulphurization (FGD).

The Least-cost scenario shows similar NOx and PM trends when compared to the Reference scenario. However, notable deviation in emissions relative to the IRP 2019 on NOx and PM is noted post 2030. This is expected as a result of no new-build coal capacity post 2030 as the new-build constraints on solar PV and wind are removed in the Reference scenario.

The equivalent average wholesale electricity tariff for this scenario is shown in Figure 51. As expected, the equivalent wholesale tariff is initially higher than the IRP 2019 (as a result of adjusted demand forecast and EAF expectation) but lower than the Reference scenario and all other scenarios explored (by definition, least-cost over the time horizon). The equivalent tariff ends at 1.08 R/kWh by 2050.



CO_2 emissions [Gt] (2020-2050)

Constraints	
PPD (Moderate)	6.7
Outcomes	
IRP 2019	5.2
Reference Scenario	4.0
Least-cost	3.9
Modest RE Industrialisation	3.5
Ambitious RE Industrialisation	3.0
Ambitious RE Ind. (coal off 2040)	2.5
2Gt CO2 budget	2.0

Figure 48. Electricity sector CO_2 emission for the Least-Cost Scenario

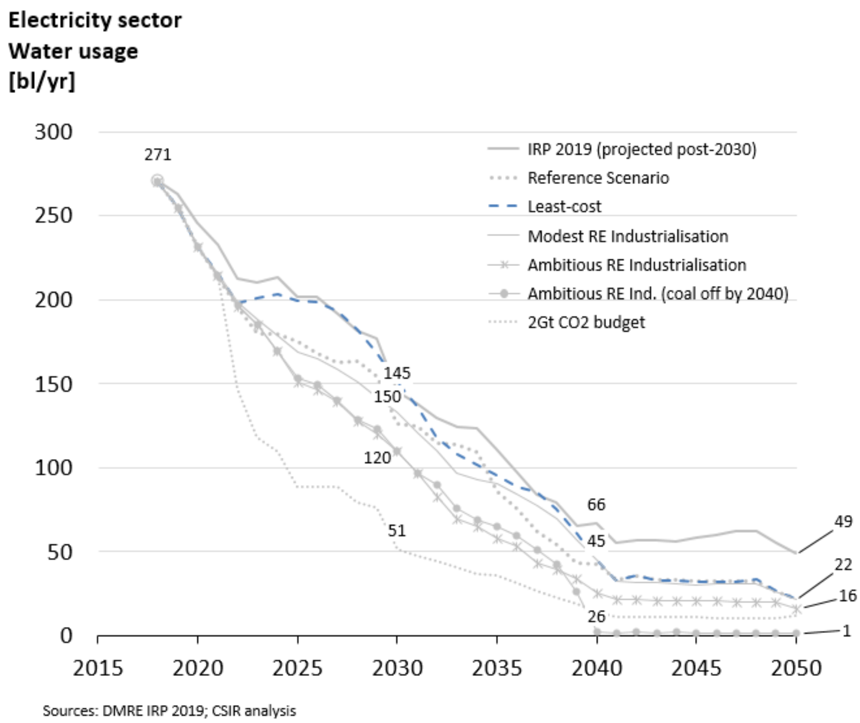


Figure 49. Electricity sector water usage for the Least-Cost Scenario

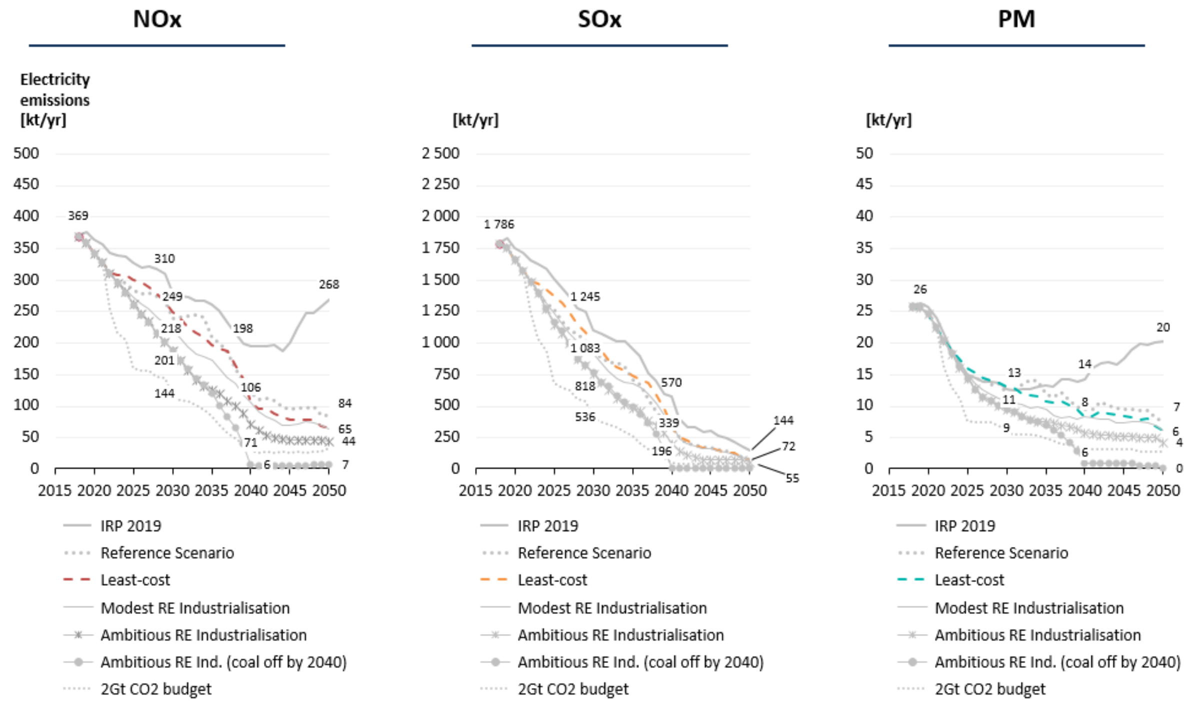
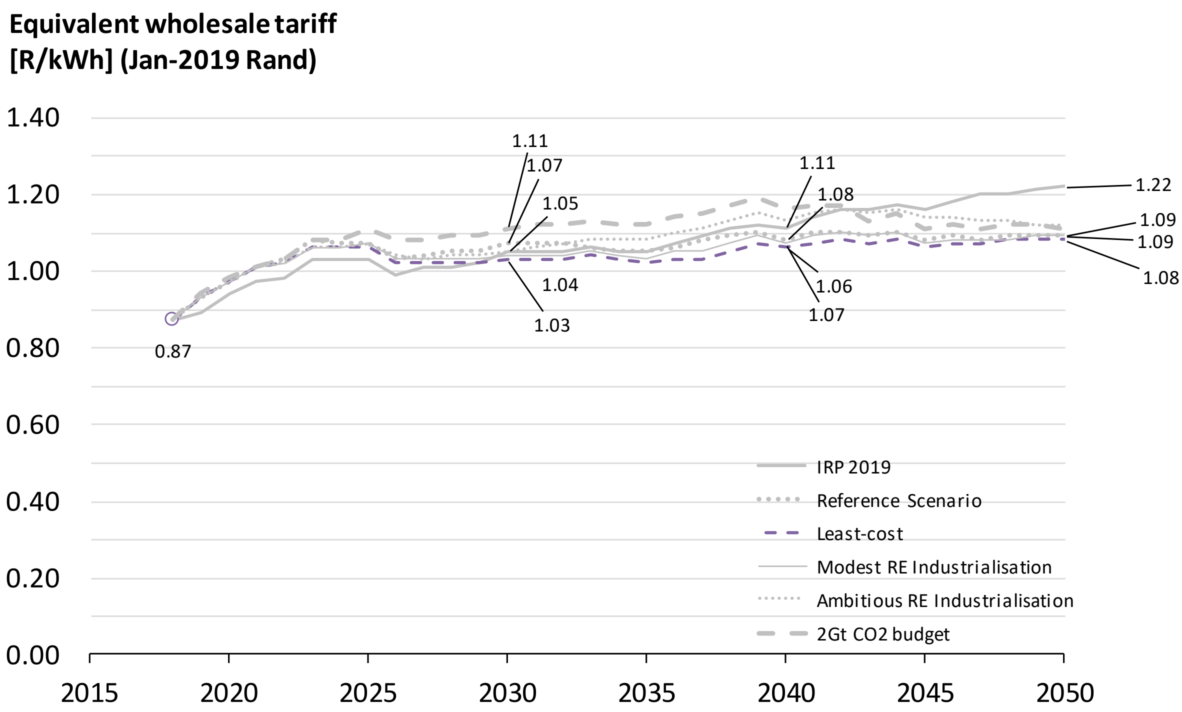


Figure 50. Electricity sector NOx, SOx and PM for the Least-Cost Scenario



Notes: Transmission (Tx), distribution (Dx), system services (often referred to as ancillary services) and other costs not explicitly included in the PLEXOS modelling framework are approximated by a high level assumption of 0.20 R/kWh for all of these cost components consistently across all scenarios.
Sources: CSIR Energy Centre analysis

Figure 51. Equivalent average tariff for Least-cost scenario

3.4 Modest RE Industrialisation

As described in section 2.2, the Modest RE industrialisation scenario builds on the outcomes of the Least-cost scenario where a more practical and implementable renewable build program is tested.

This scenario aims to smooth the wind and solar PV annual new build over the planning horizon in order to represent a more sustainable and achievable build-out programme considering the already known outcomes from the Least-cost scenario. Thus, this scenario assumes the same input assumptions as the Least-cost scenario with the only changes being dynamically smoothed minimum new-build limits on solar PV and wind specifically. These dynamically smoothed minimum new-build limits are shown in section 2.3.8.

This scenario is defined by the following input assumptions:

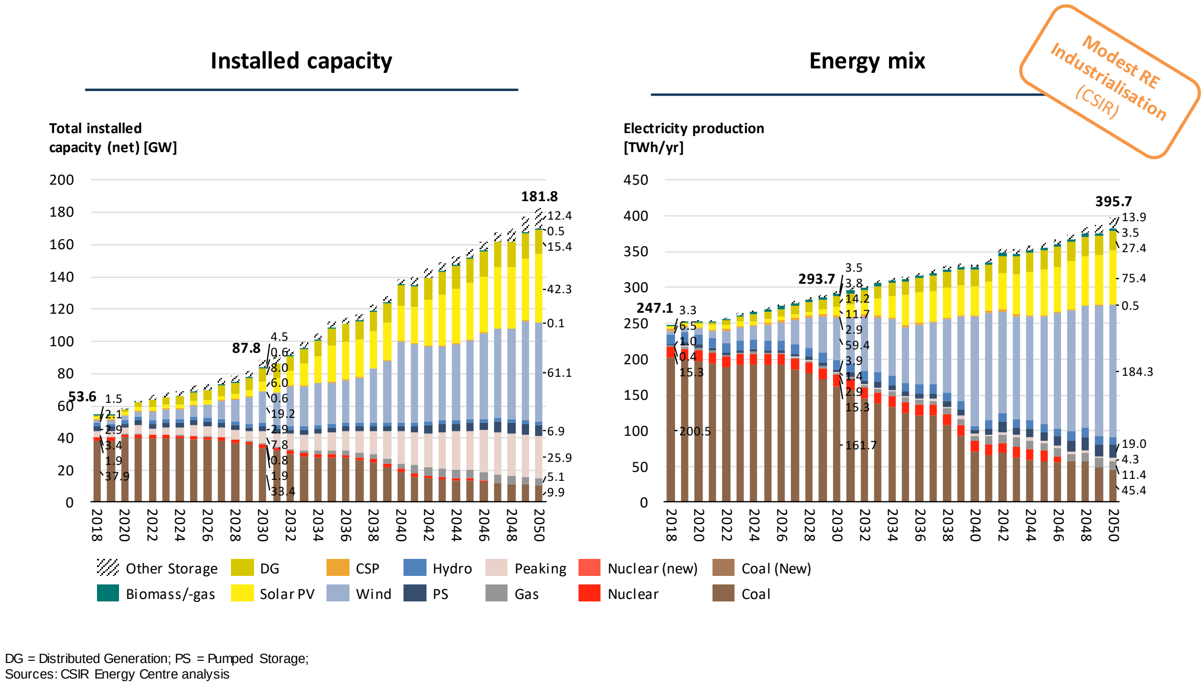
Modest RE Industrialisation	
Demand Forecast	*Updated demand (CSIR) (see Figure 13)*
Carbon emission constraint	*None*
Existing fleet performance	*Updated EAF (CSIR) (see Figure 18)*
Existing coal fleet decommissioning	*Endogenous decommissioning*
Short-term emergency options[8]	*Included*
Forced in new build technologies	*None*
Wind/solar PV annual new build constraints	*None (only minimum new-build)*
New technology costs:	*Updated technology costs (CSIR)*

The capacity and energy contribution per technology type for this scenario is shown in Figure 52 for the full study horizon. With the minimum new-build constraints included in this scenario (to enable a dynamically smoothed new-build of solar PV and wind capacity), the energy mix by 2030 changes relative to the Least-cost with 49% of the energy mix being carbon-free (44% renewables) by 2030 but a similar energy mix by 2050 with 76% carbon-free (76% renewables). Short duration battery storage deployment is supplemented by pumped storage capacity similar to that of the modest RE Least-cost scenario (as expected). No new-build nuclear, coal or CSP capacity is built in this scenario.

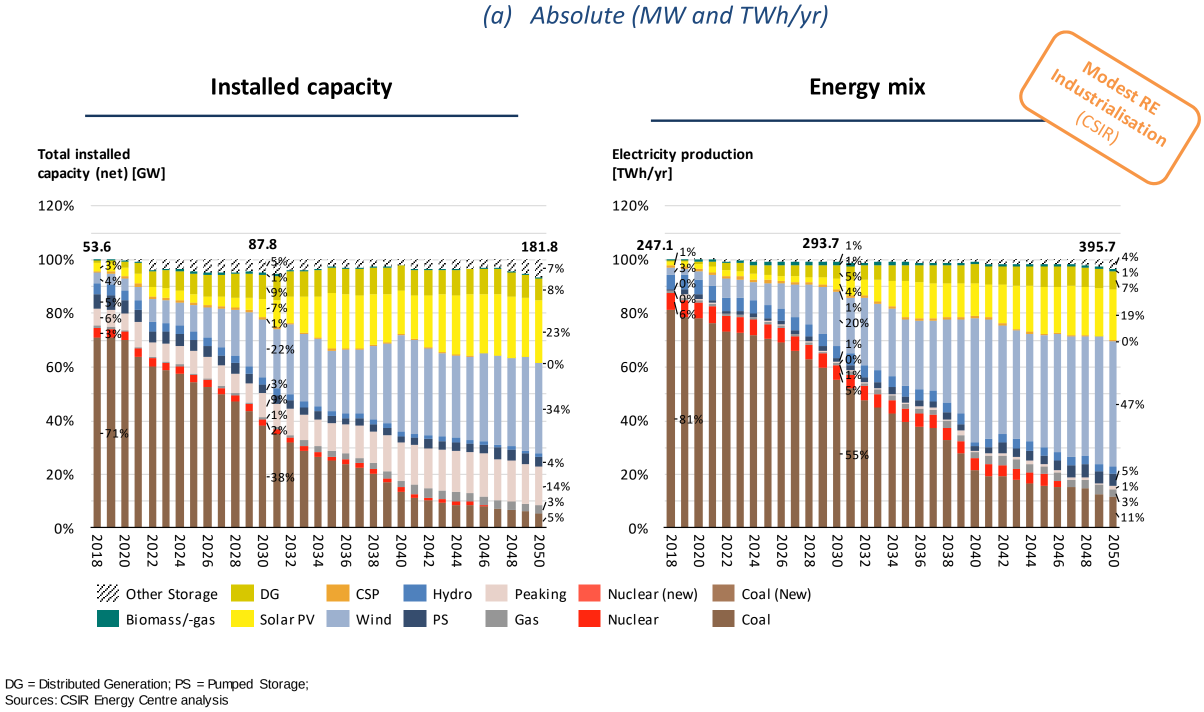
As shown in Figure 53, no earlier than expected decommissioning of the coal fleet (50-year life) is

[8] Includes immediate customer response at scale (mostly embedded/distributed solar PV, storage) and other short-term risk mitigation capacity to ensure adequacy gap is met (portfolio of technologies/options)

expected. By the end of the planning horizon, 9.9 GW of coal capacity comprising two units at Majuba and the under construction Medupi and Kusile capacity is still operational.

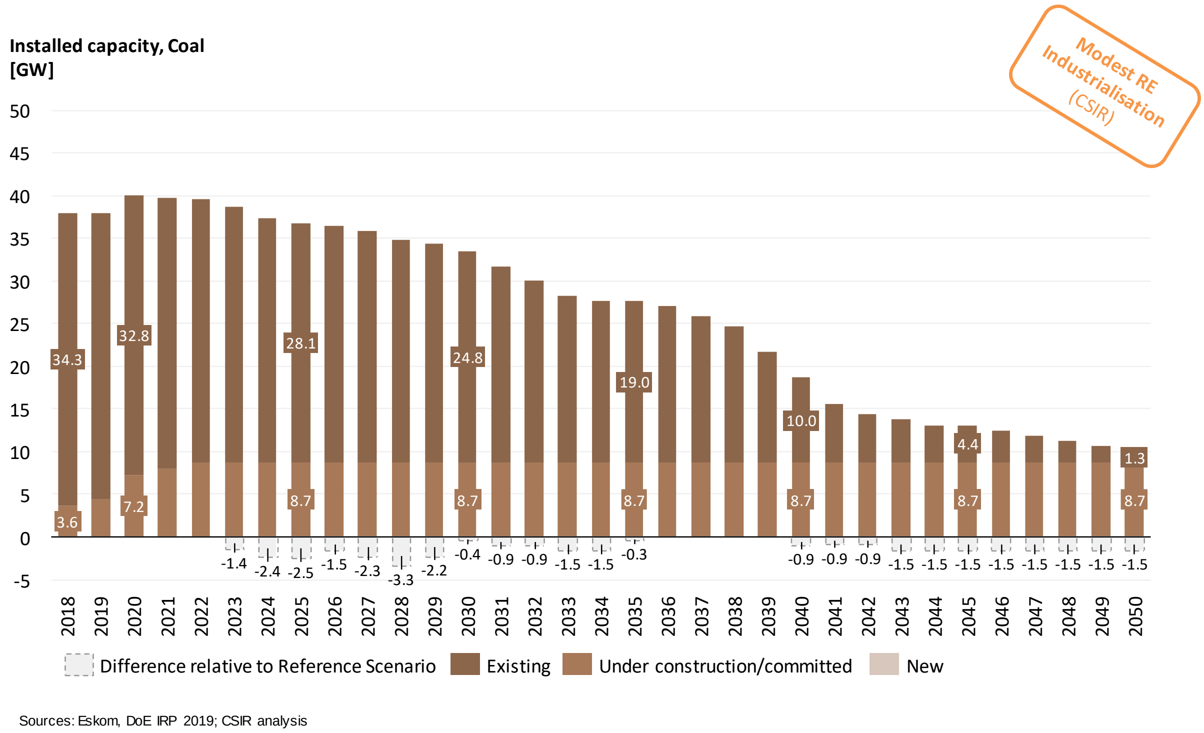


(a) Absolute (MW and TWh/yr)

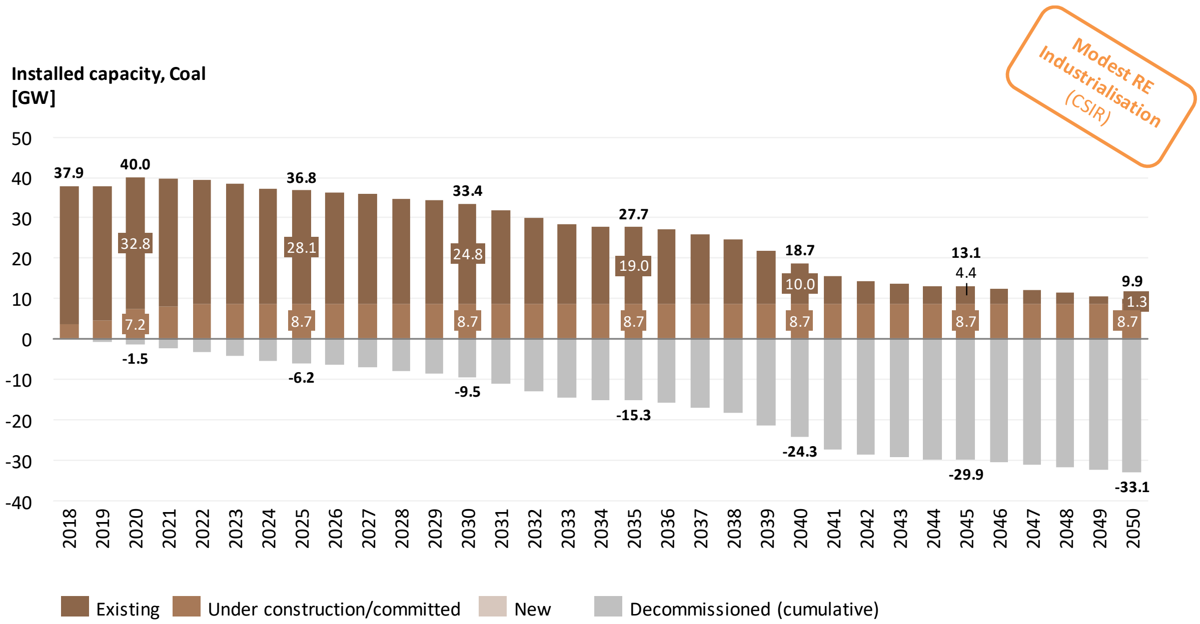


(b) Share (%)

Figure 52. Installed capacity and energy mix for the Modest RE Industrialisation scenario from 2018-2050



(a) Existing, under construction and new coal capacity



(b) Existing, under construction and new coal capacity combined with cumulative decommissioned coal capacity

Figure 53. Existing, under construction and new coal capacity in the Modest RE Industrialisation scenario

The electricity sector CO_2 emissions, water usage, SOx, NOx and particulate matter (PM) resulting from this scenario are shown in Figure 54 - Figure 56. An accelerated downward trend in CO_2 emissions relative to the Least-cost scenario is observed (as expected). A total of ≈3.5 Gt of electricity sector CO_2 emissions are produced over the horizon (2020-2050).

Water usage, SOx, NOx and particulate matter (PM) emissions are also similar to that of the Least-cost scenario but with a smoothed profile as the smoothed renewable energy deploys over the time horizon.

The equivalent average wholesale electricity tariff for this scenario is shown in Figure 57. The expectation for the equivalent wholesale tariff is initially higher in this scenario relative to the Least-cost scenario as earlier than least-cost optimal renewable energy deployments are imposed in this scenario (as expected). Following this initial deviation, the wholesale average tariff is expected to follow a similar trend to that of the Least-cost scenario.

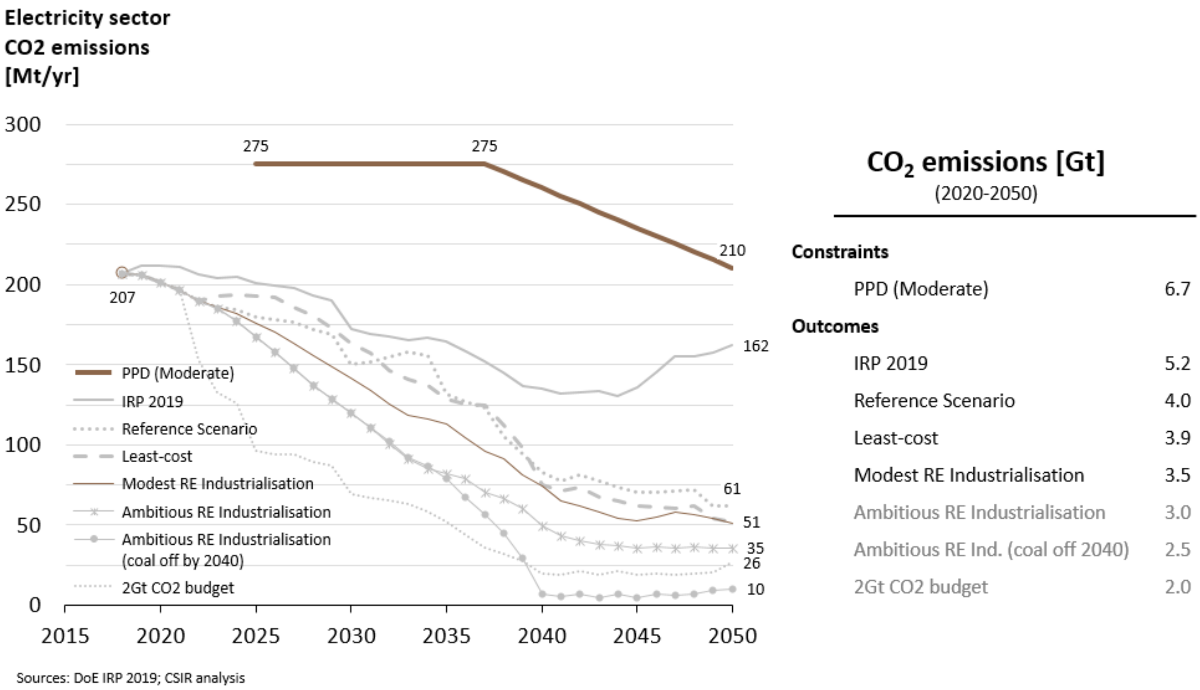


Figure 54. Electricity sector CO_2 emission for the Modest RE Industrialisation scenario

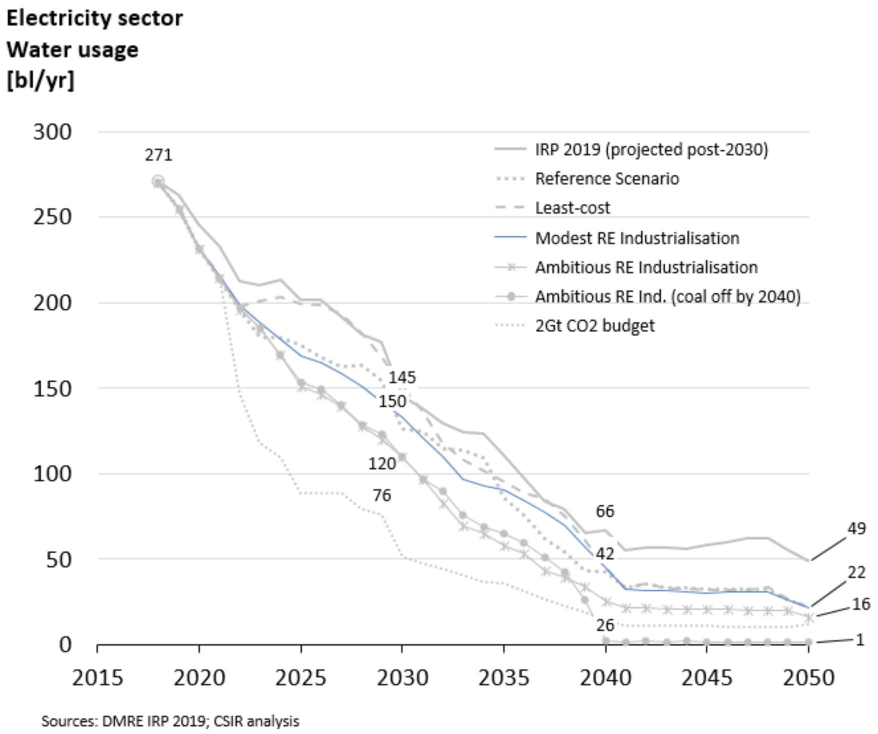


Figure 55. Electricity sector water usage for the Modest RE Industrialisation scenario

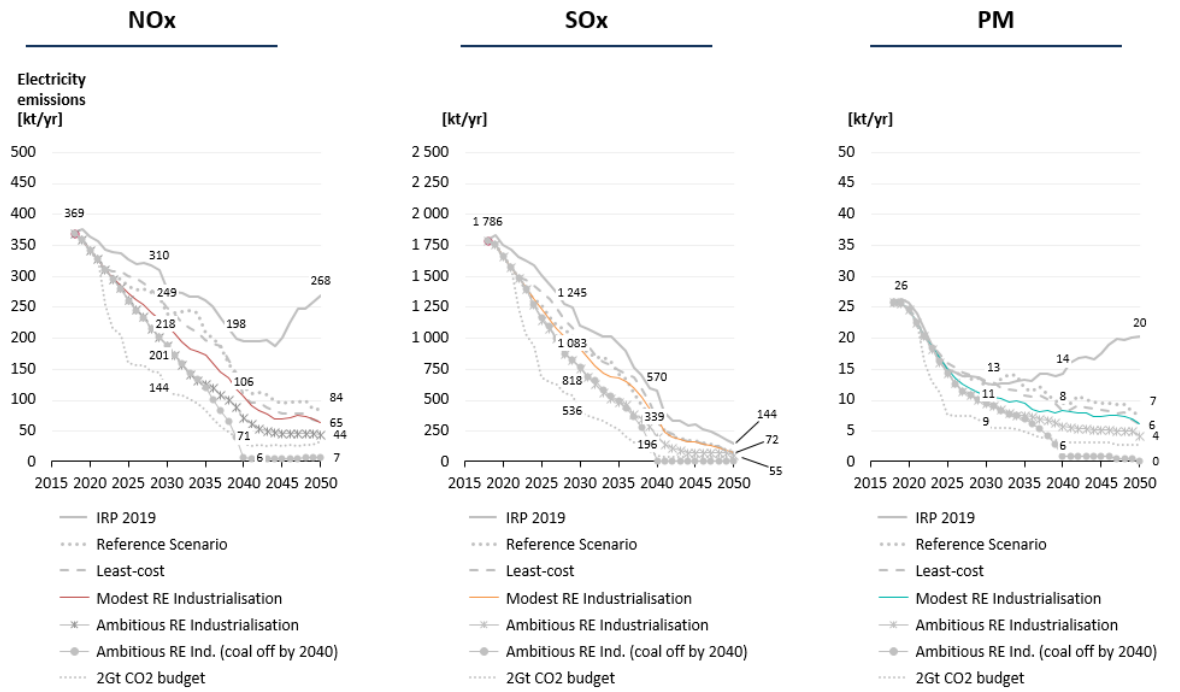
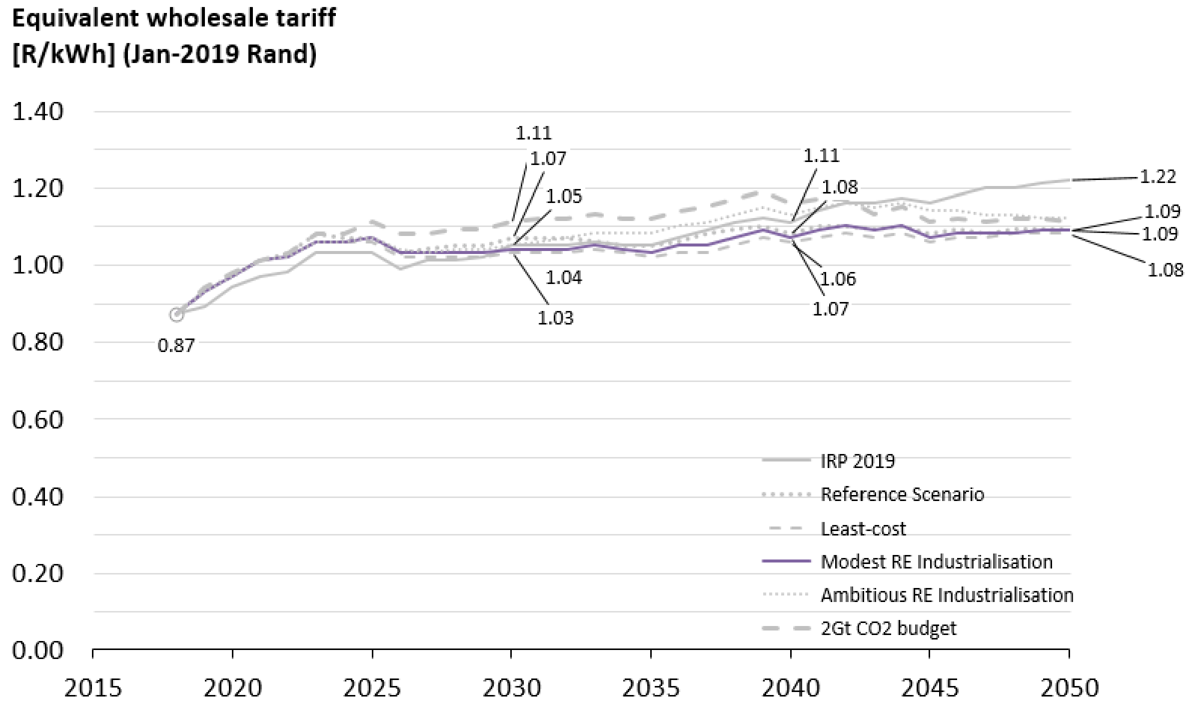


Figure 56. Electricity sector NOx, SOx and PM for the Modest RE Industrialisation scenario



Notes: Transmission (Tx), distribution (Dx), system services (often referred to as ancillary services) and other costs not explicitly included in the PLEXOS modelling framework are approximated by a high level assumption of 0.20 R/kWh for all of these cost components consistently across all scenarios.
Sources: CSIR Energy Centre analysis

Figure 57. Equivalent average tariff for Modest RE industrialisation scenarios

3.5 Ambitious RE Industrialisation

As with the Modest RE Industrialisation scenario, the Ambitious RE industrialisation scenario aims to smooth the wind and solar PV annual new build over the planning horizon but more aggressively than the Modest RE Industrialisation scenario. This scenario assumes the same input assumptions as the Least-cost scenario with the only changes being dynamic minimum new-build limits on solar PV and wind specifically. These dynamically smoothed minimum new-build limits are shown in section 2.3.8.

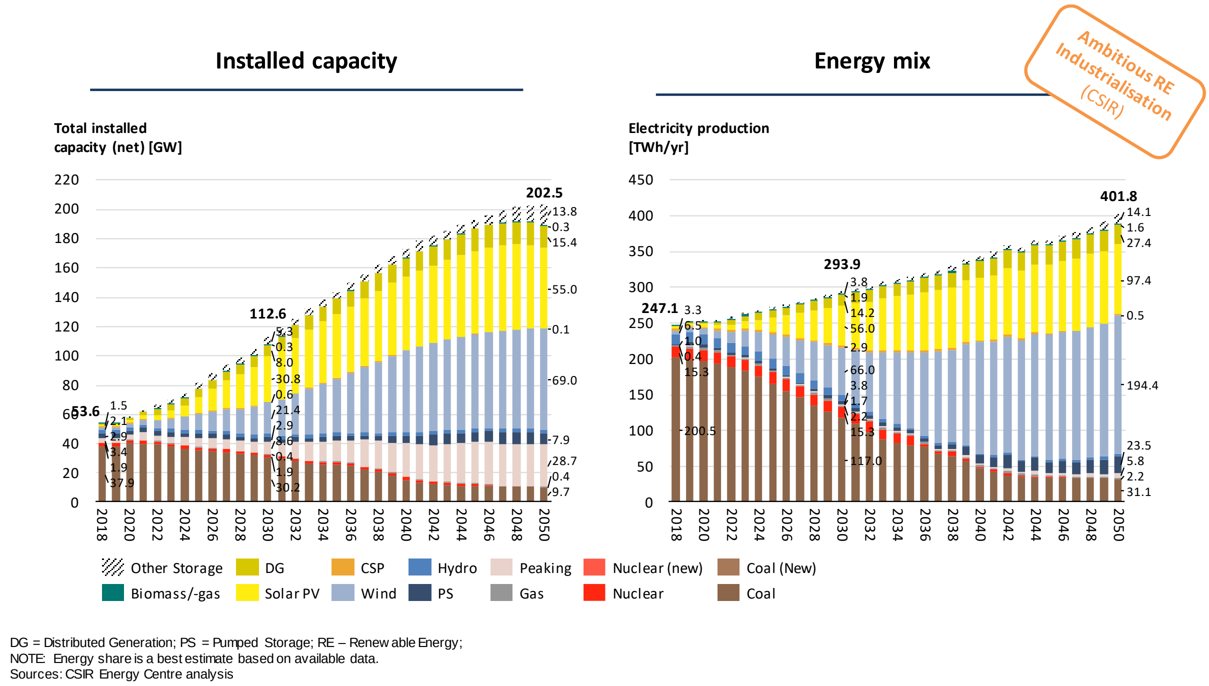
This scenario is defined by the following input assumptions:

Ambitious RE Industrialisation	
Demand Forecast	*Updated demand (CSIR) (see Figure 13)*
Carbon emission constraint	*None*
Existing fleet performance	*Updated EAF (CSIR) (see Figure 18)*
Existing coal fleet decommissioning	*Endogenous decommissioning*
Short-term emergency options[9]	*Included*
Forced in new build technologies	*None*
Wind/solar PV annual new build constraints	*None (only minimum new-build)*
New technology costs:	*Updated technology costs (CSIR)*

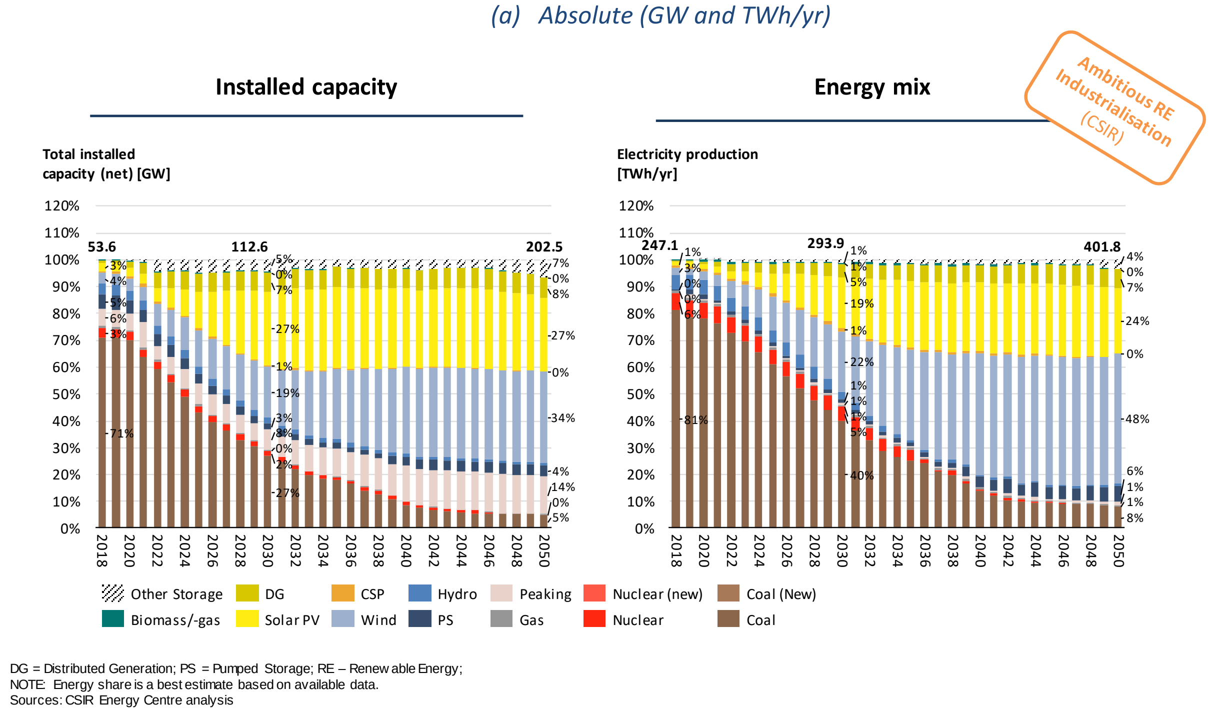
The capacity and energy contribution per technology type for this scenario is shown in Figure 58 for the full study horizon. The energy mix by 2030 shows a significantly increased role of renewables with 56% of the energy mix being carbon-free (51% renewables) by 2030 and an increased role for renewables by 2050 of 81%. As short duration battery storage is deployed throughout the time horizon in this scenario, pumped storage capacity starts to deploy after 2035 and ramps up to the full 5.0 GW after 2045 as increased variable renewable energy is deployed requiring additional longer duration storage. No new-build nuclear, coal or CSP capacity is built in this scenario.

As shown in Figure 59, some early decommissioning of the coal fleet (50-year life) is expected with a higher renewable energy build out than the Reference Scenario (≈4 GW less coal by 2030 than the Reference Scenario). By the end of the planning horizon, a similar amount of coal capacity remains online (9.9 GW).

[9] Includes immediate customer response at scale (mostly embedded/distributed solar PV, storage) and other short-term risk mitigation capacity to ensure adequacy gap is met (portfolio of technologies/options)

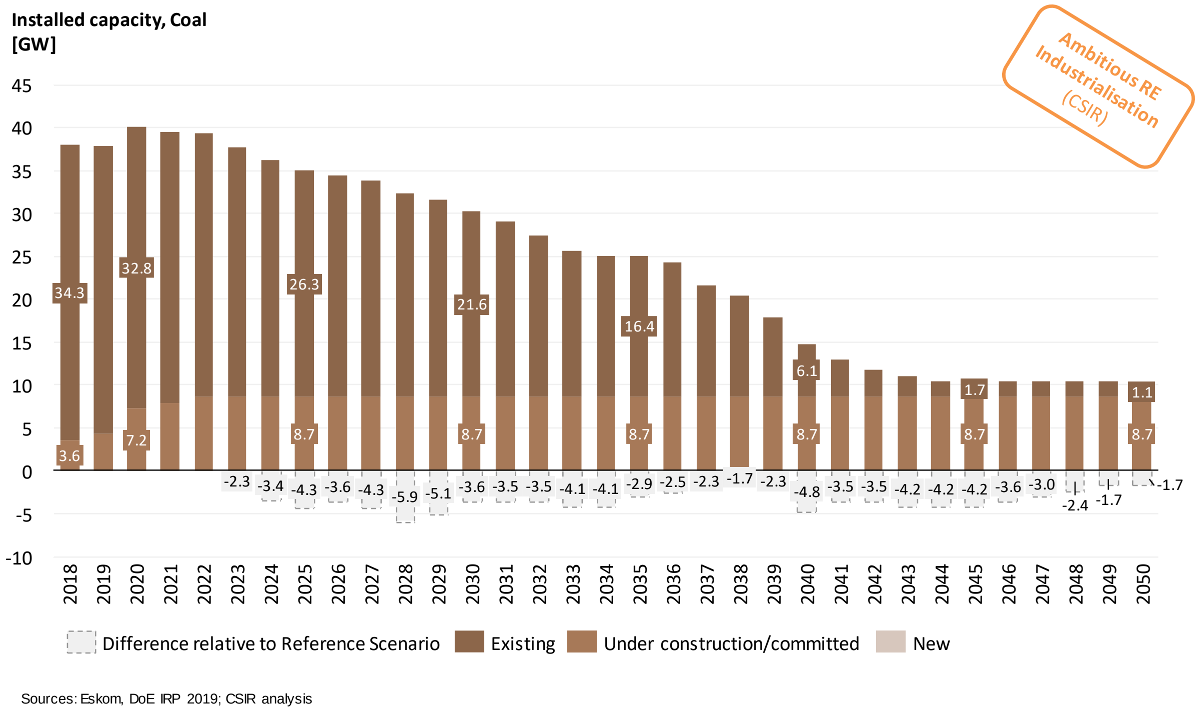


(a) Absolute (GW and TWh/yr)

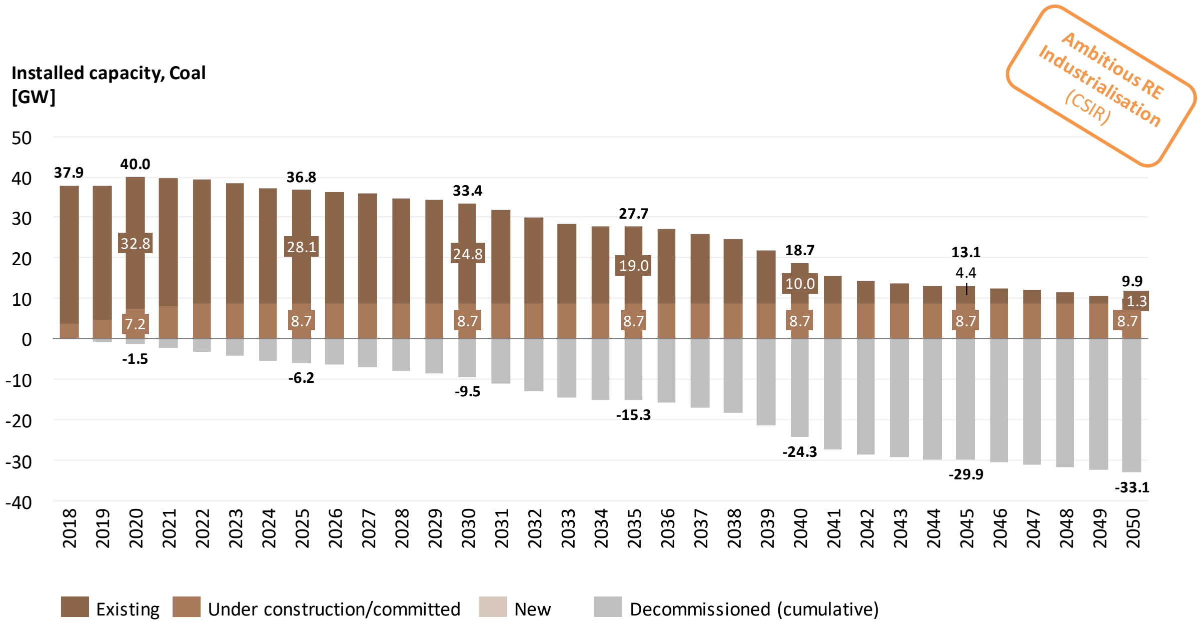


(b) Share (%)

Figure 58. Installed capacity and energy mix for the Ambitious RE Industrialisation scenario from 2018-2050



(a) Total installed coal capacity



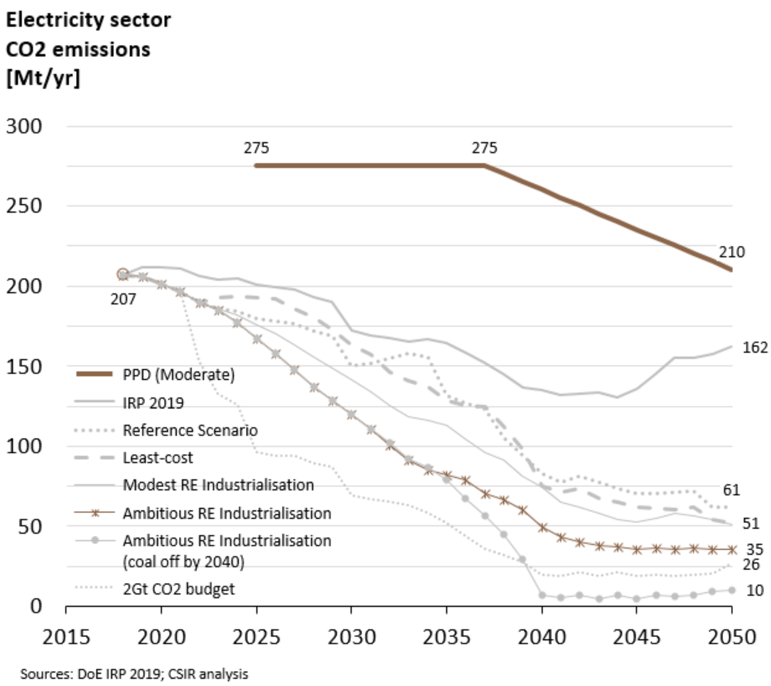
(b) Existing, under construction and new coal capacity combined with cumulative decommissioned coal capacity

Figure 59. Existing, under construction and new coal capacity in the Ambitious RE Industrialisation scenario

The electricity sector CO_2 emissions, water usage, SOx, NOx and particulate matter (PM) resulting from this scenario are shown in Figure 60 - Figure 62. A similar trend to the Least-cost scenario is observed (as expected). A total of ≈3.0 Gt of electricity sector CO_2 emissions are produced over the horizon (2020-2050).

Water usage, SOx, NOx and particulate matter (PM) emissions are also similar to that of the Least-cost scenario but with a lower earlier trajectory as a result of earlier than least-cost optimal deployment of solar PV and wind resulting in lower utilization of the existing coal fleet where emissions are dominant.

The equivalent wholesale electricity tariff for this scenario is shown in Figure 63. The expectation for the equivalent wholesale tariff is higher than that of the Least-cost and Modest RE Industrialisation scenarios and is driven by higher than least-cost optimal amounts of RE being included as a result of the minimum new-build constraints defined. The equivalent wholesale electricity tariff is 1.05 R/kWh by 2030 with an increase to 1.13 R/kWh by 2040 as accelerated levels of RE are incorporated but declines thereafter towards 1.12 R/kWh by 2050



CO_2 emissions [Gt]
(2020-2050)

Constraints	
PPD (Moderate)	6.7
Outcomes	
IRP 2019	5.2
Reference Scenario	4.0
Least-cost	3.9
Modest RE Industrialisation	3.5
Ambitious RE Industrialisation	3.0
Ambitious RE Ind. (coal off 2040)	2.5
2Gt CO2 budget	2.0

Figure 60. Electricity sector CO_2 emission for the Ambitious RE Industrialisation scenario

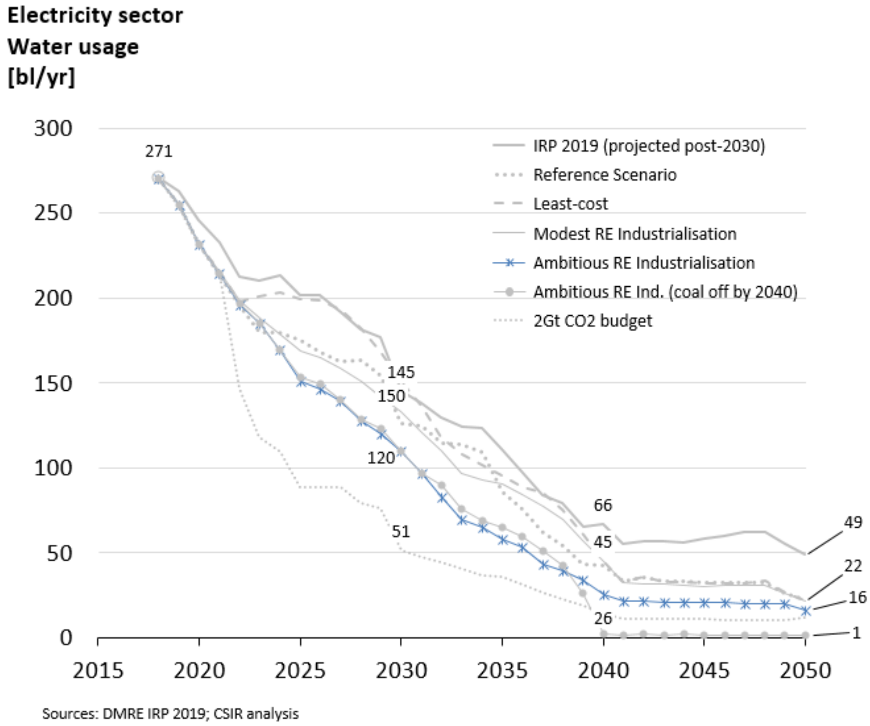


Figure 61. Electricity sector water usage for the Ambitious RE Industrialisation scenario

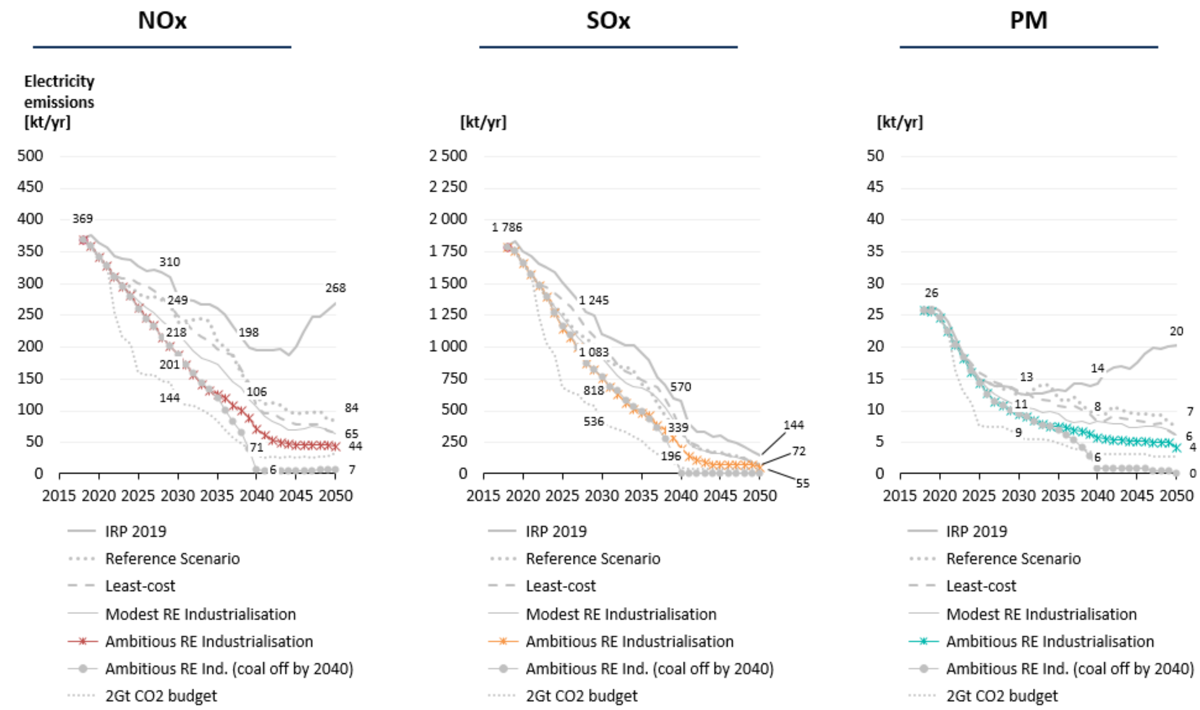
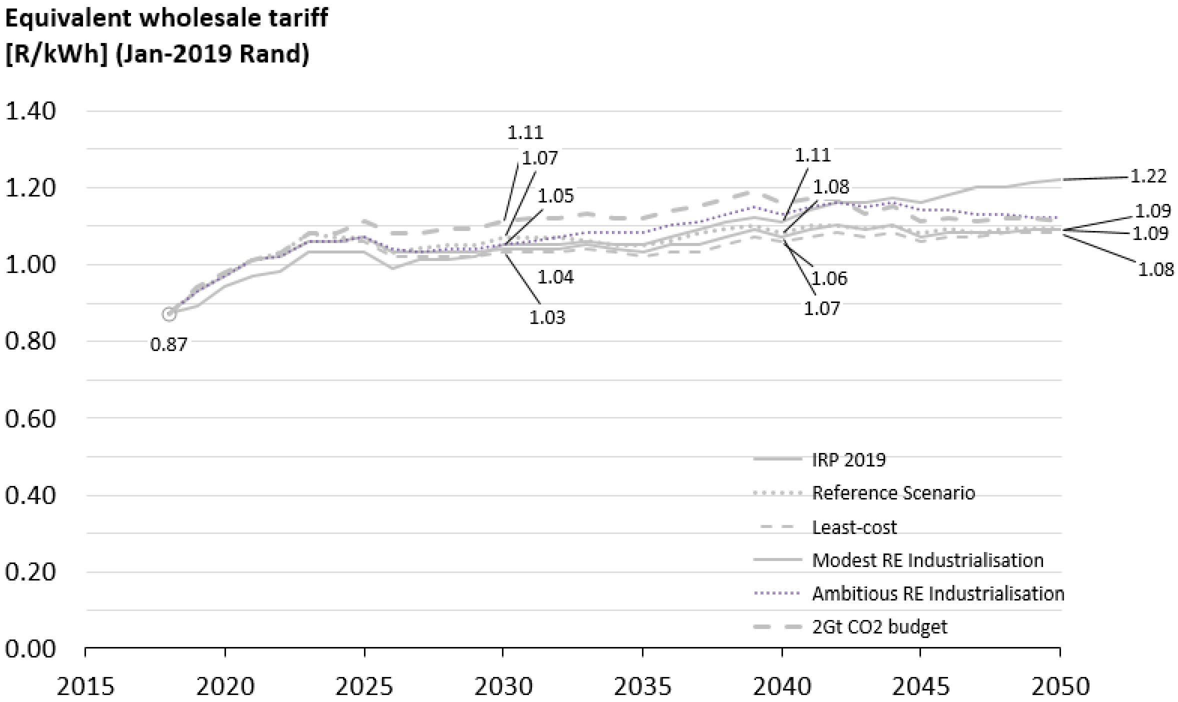


Figure 62. Electricity sector NOx, SOx and PM for the Ambitious RE Industrialisation scenario



Notes: Transmission (Tx), distribution (Dx), system services (often referred to as ancillary services) and other costs not explicitly included in the PLEXOS modelling framework are approximated by a high level assumption of 0.20 R/kWh for all of these cost components consistently across all scenarios.
Sources: CSIR Energy Centre analysis

Figure 63. Equivalent average tariff for the Ambitious RE industrialisation scenario

3.6 Ambitious RE Industrialisation (coal off by 2040)

As with the Ambitious RE industrialisation scenario, wind and solar PV annual new build is smoothed over the planning horizon as per the same minimum build constraints. In addition to this, this scenario enforces that all coal-fired capacity is decommissioned by 2040, in order to further reduce carbon emissions. As previously mentioned, this is a representative scenario to test a "what if" hypothesis but could be repeated for any year where the choice for all coal to be decommissioned is opted for.

This scenario is defined by the following input assumptions:

Ambitious RE Industrialisation (coal off by 2040)	
Demand Forecast	*Updated demand (CSIR) (see Figure 13)*
Carbon emission constraint	*None*
Existing fleet performance	*Updated EAF (CSIR) (see Figure 18)*
Existing coal fleet decommissioning	*Endogenous decom. , all off by 2040*
Short-term emergency options[10]	*Included*
Forced in new build technologies	*None*
Wind/solar PV annual new build constraints	*None (only minimum new-build)*
New technology costs:	*Updated technology costs (CSIR)*

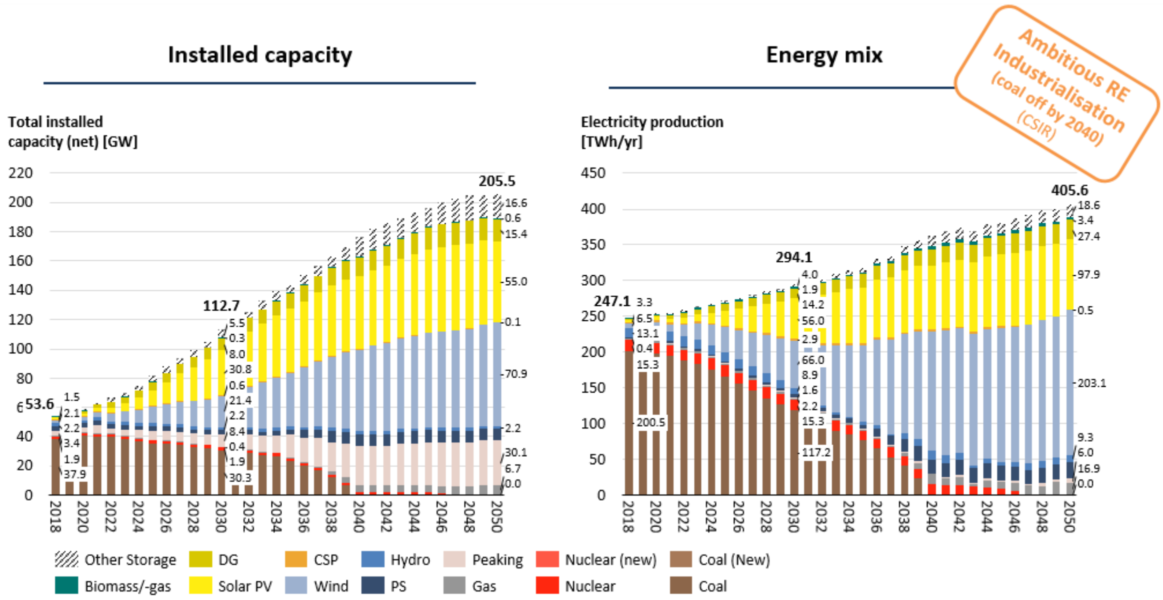
The capacity and energy contribution per technology type for this scenario is shown in Figure 64 for the full study horizon. As expected, the energy mix by 2030 is identical to the previous scenario, with key changes to the energy mix occurring post 2035 as the coal fleet starts to decommission in order to meet the binding constraint whereby all coal must be retired by 2040. The renewable energy capacity remained largely unchanged relative to the previous scenario, indicating a likely overbuild of wind/solar PV in the Ambitious minimum build constraint, with additional storage and gas capacity being built to replace the coal fleet. Although additional short duration battery storage is also part of the outcomes of this scenario, with the coal fleet being fully decommissioned by 2040, the full 5.0 GW of pumped storage capacity is deployed by 2038 already. No new-build nuclear, coal or CSP capacity is built in this scenario.

As shown in Figure 65, some early decommissioning of the coal fleet (50-year life) is expected with all coal decommissioned by 2040. The seemingly smoothed decommissioning of the coal capacity by

10 Includes immediate customer response at scale (mostly embedded/distributed solar PV, storage) and other short-term risk mitigation capacity to ensure adequacy gap is met (portfolio of technologies/options)

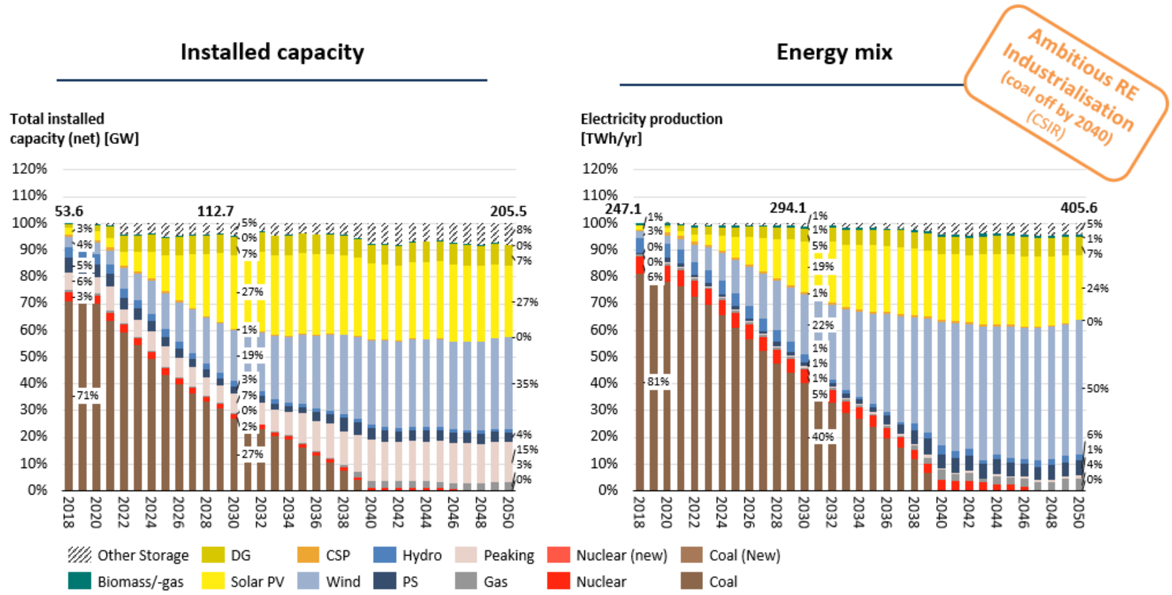
2040 is as a result of the previously described assumption that only one (1) coal unit can be decommissioned per year (for large coal stations) whilst the smaller coal stations can decommission a maximum of two (2) units per year.

The decommissioning by 2040 drives a greater need for mid-merit gas-fired capacity beyond 2040 compared to the Ambitious RE Industrialisation scenario. Further analysis on this is provided in section 3.8 where scenario outcomes are compared further.



DG = Distributed Generation; PS = Pumped Storage
NOTE: Energy share is a best estimate based on available data.
Sources: CSIR Energy Centre analysis

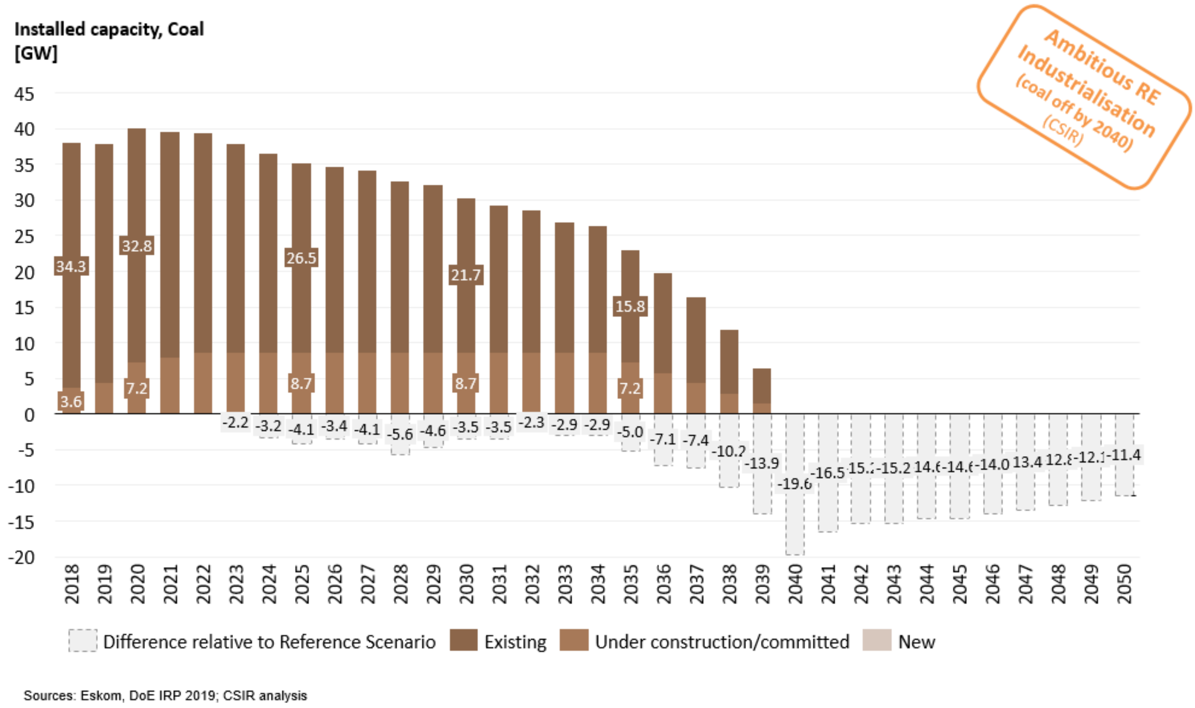
(a) Absolute (GW and TWh/yr)



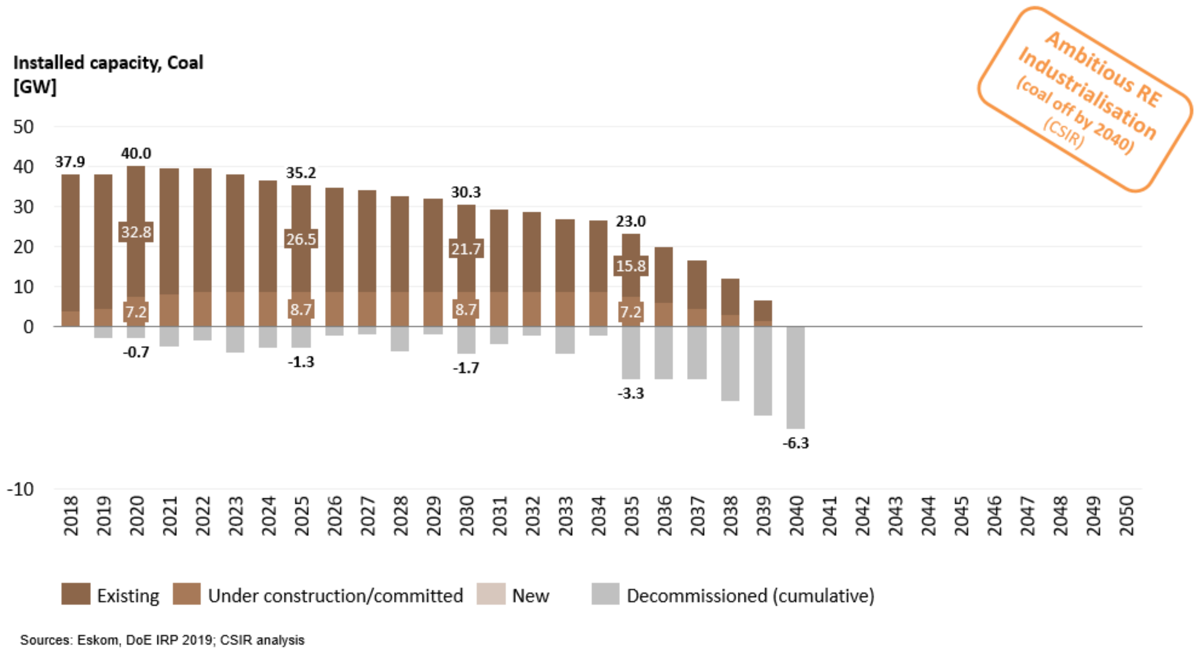
DG = Distributed Generation; PS = Pumped Storage; RE – Renewable Energy;
NOTE: Energy share is a best estimate based on available data.
Sources: CSIR Energy Centre analysis

(b) Share (%)

Figure 64. Installed capacity and energy mix for the Ambitious RE Industrialisation scenario (coal off by 2040) from 2018-2050



(a) Total installed coal capacity



(b) Existing, under construction and new coal capacity combined with cumulative decommissioned coal capacity

Figure 65. Existing, under construction and new coal capacity in the Ambitious RE Industrialisation (coal off by 2040) scenario

The electricity sector CO_2 emissions, water usage, SOx, NOx and particulate matter (PM) resulting from this scenario are shown in Figure 66 - Figure 68. A similar trend to the previous scenario is observed (as expected) with a rapid reduction in CO_2 once the coal-fleet is fully decommissioned. There is a slight uptick in CO_2 emissions in the last 2 years from increased gas-fired utilization. A total of ≈2.5 Gt of electricity sector CO_2 emissions are produced over the horizon (2020-2050).

Water usage, SOx, NOx and particulate matter (PM) emissions are also similar to that of the previous scenario but with a rapid reduction leading to 2040. Without any coal capacity after 2040, minute SOx emissions and minimal annual volumes of NOx and PM are emitted (along with water usage being almost zero). The remaining emissions contributors are dominated by natural gas fired generation capacity (with minute contributions from biomass/-gas).

The equivalent wholesale electricity tariff for this scenario is shown in Figure 69. The expectation for the equivalent wholesale tariff is higher than that of Ambitious RE Industrialisation scenario, driven by the full decommissioning of the coal fleet post 2040. The equivalent wholesale electricity tariff is 1.05 R/kWh by 2030 with an increase to 1.19 R/kWh by 2040 as accelerated levels of RE are incorporated but declines thereafter towards 1.17 R/kWh by 2050.

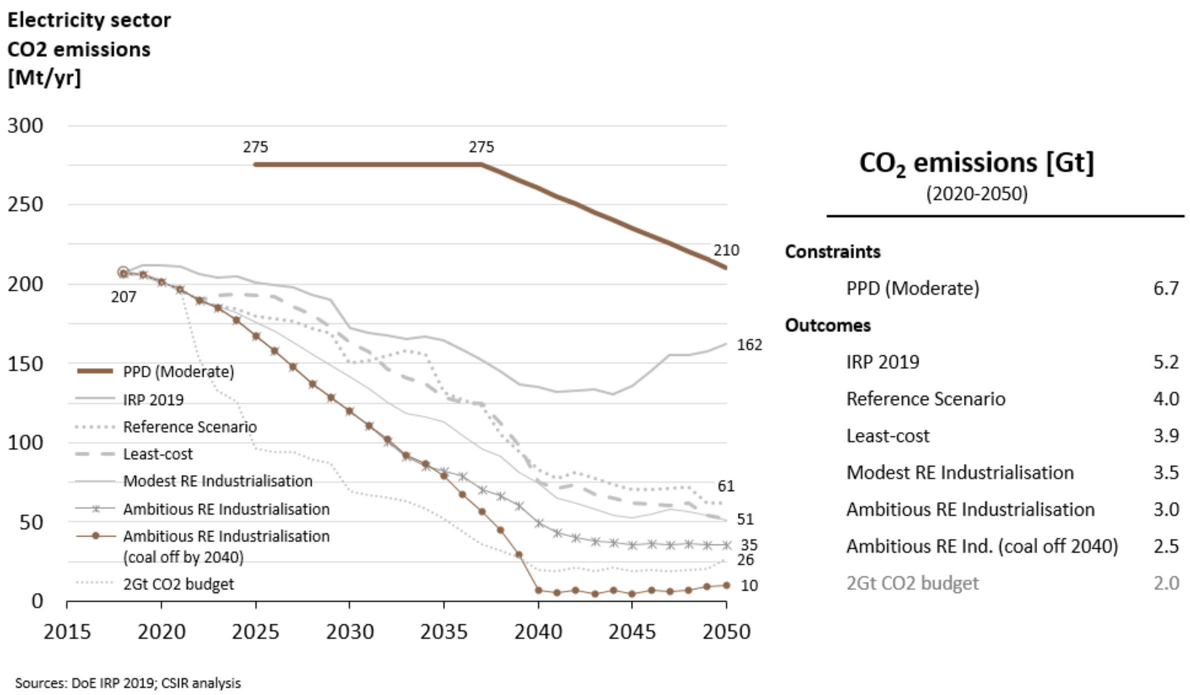


Figure 66. Electricity sector CO_2 emission for the Ambitious RE Industrialisation (coal off by 2040) scenario

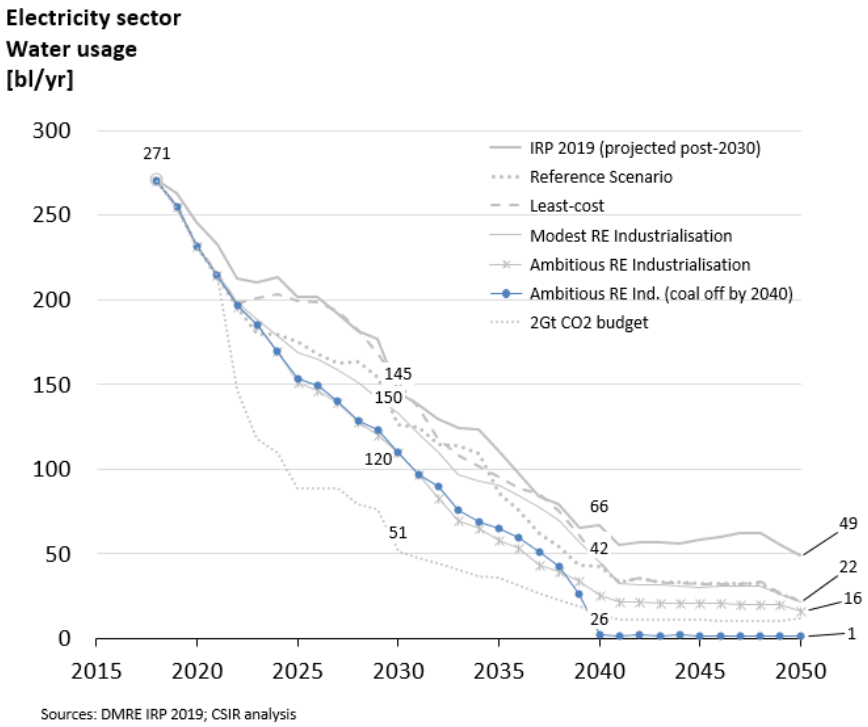


Figure 67. Electricity sector water usage for the Ambitious RE Industrialisation (coal off by 2040) scenario

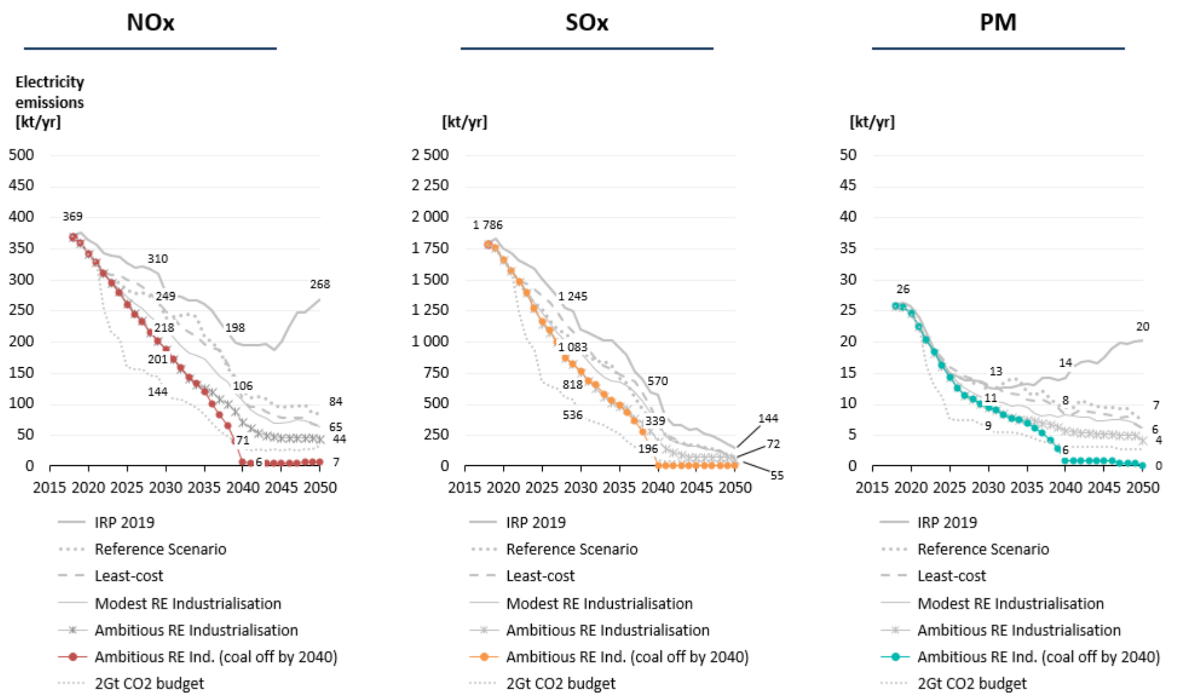


Figure 68. Electricity sector NOx, SOx and PM for the Ambitious RE Industrialisation (coal off by 2040) scenario

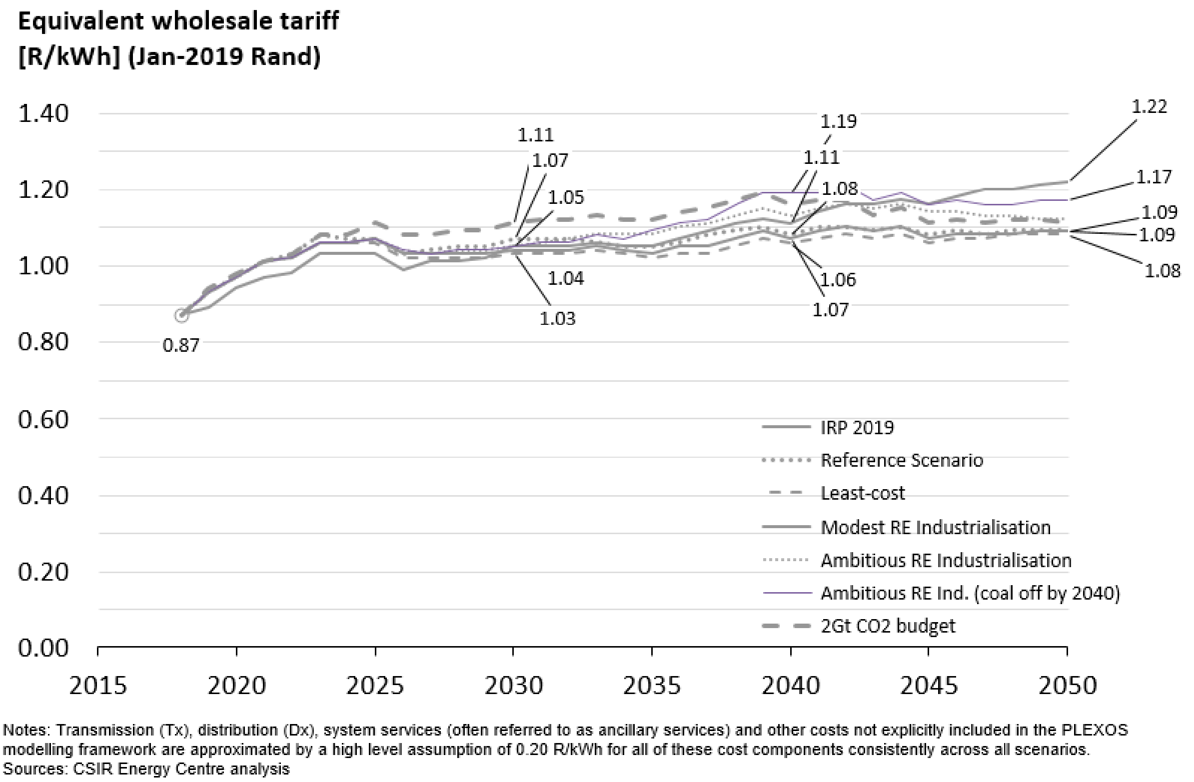


Figure 69. Equivalent average tariff for the Ambitious RE industrialisation (coal off by 2040) scenario

3.7 2 Gt CO_2 budget

As described in section 2.2, the 2Gt budget scenario assumes the same input assumptions as Least-cost scenario but with a total CO_2 budget constraint of 2 Gt applied for the period 2020 – 2050.

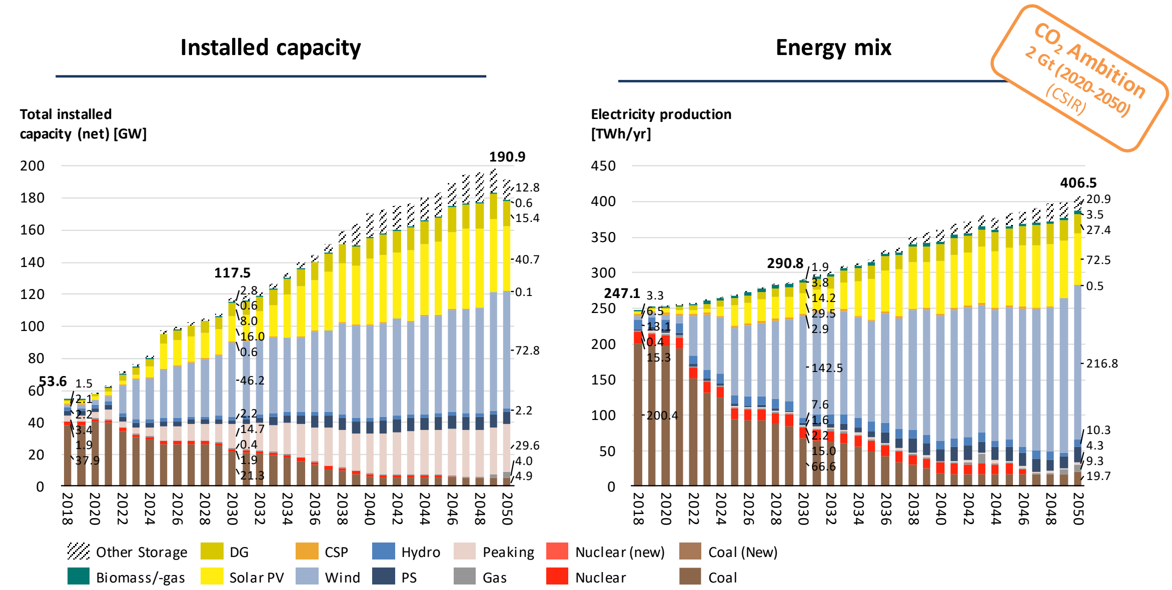
This scenario is defined by the following input assumptions:

2 Gt CO_2 budget	
Demand Forecast	*Updated demand (CSIR) (see Figure 13)*
Carbon emission constraint	*2 Gt CO_2 budget (2020 – 2050)*
Existing fleet performance	*Updated EAF (CSIR) (see Figure 18)*
Existing coal fleet decommissioning	*Endogenous decommissioning*
Short-term emergency options[11]	*Included*
Forced in new build technologies	*None*
Wind/solar PV annual new build constraints	*None*
New technology costs:	*Updated technology costs (CSIR)*

The capacity and energy contribution per technology type for this is shown in Figure 70 for the full study horizon. The energy mix is transformed from a coal heavy energy mix to one that is dominated by carbon-free electricity by 2030 already contributing 74% to the energy mix (69% renewables) and 82% renewables by 2050. The short-duration battery storage deployed throughout the time horizon is supplemented by long duration pumped storage capacity, with the maximum 5.0 GW fully deployed by as early as 2035 already. No new-build nuclear, coal or CSP capacity is built in this scenario.

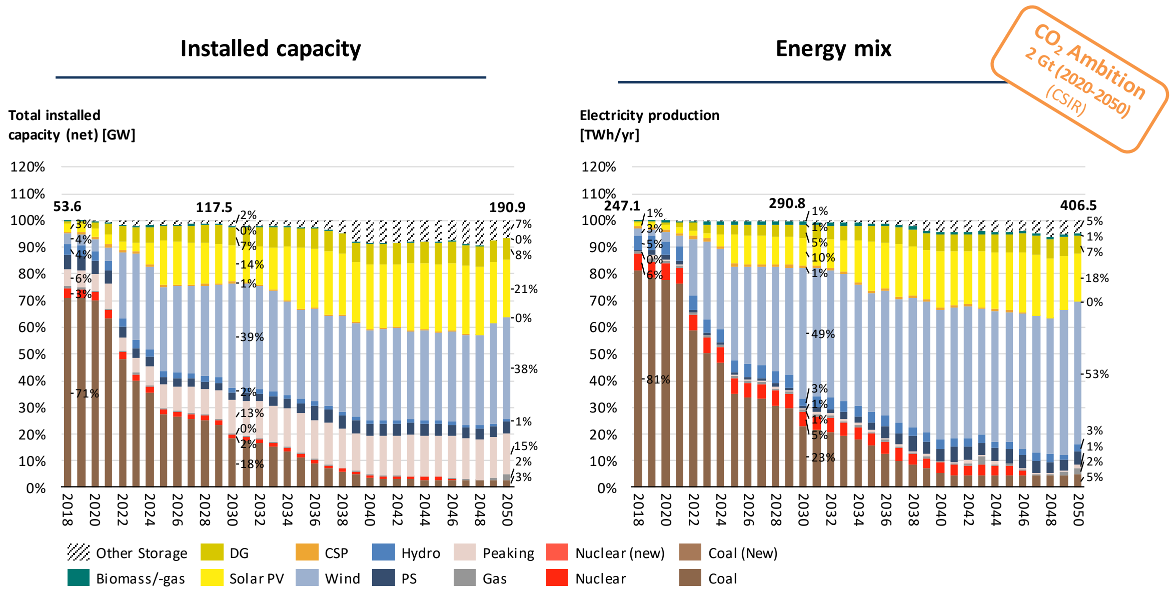
As shown in Figure 71, earlier than planned decommissioning of coal capacity occurs with 17.8 GW decommissioned by 2030 relative to 9.5-10.7 GW in the IRP 2019, Reference, Modest RE Industrialisation and Ambitious RE Industrialisation scenarios. By 2050, only 4.9 GW of coal capacity remains relative to 9.9 GW in the other scenarios. The coal capacity that is decommissioned earlier than planned (50-year life) includes Kendal, Kriel, Majuba, Matimba, Matla and Tutuka whilst Kusile is also decommissioned earlier than the planned 50 year technical life.

[11] Includes immediate customer response at scale (mostly embedded/distributed solar PV, storage) and other short-term risk mitigation capacity to ensure adequacy gap is met (portfolio of technologies/options)



DG = Distributed Generation; PS = Pumped Storage
NOTE: Energy share is a best estimate based on available data.
Sources: CSIR Energy Centre analysis

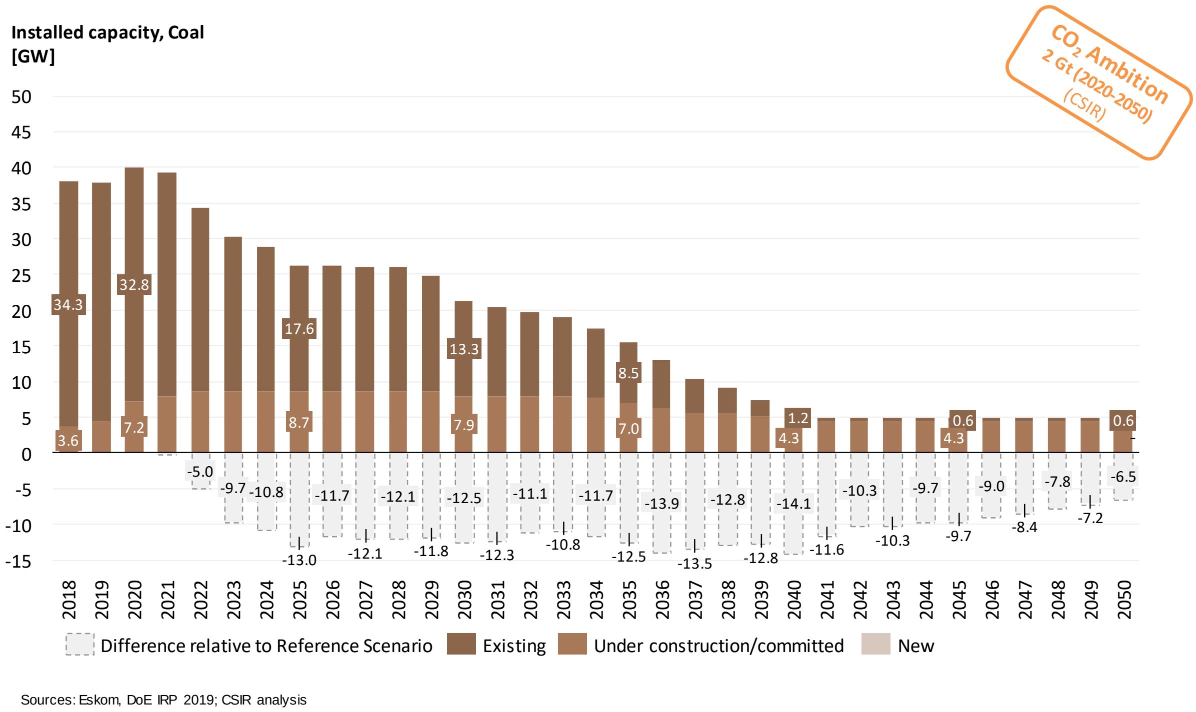
(a) Absolute (GW and TWh/yr)



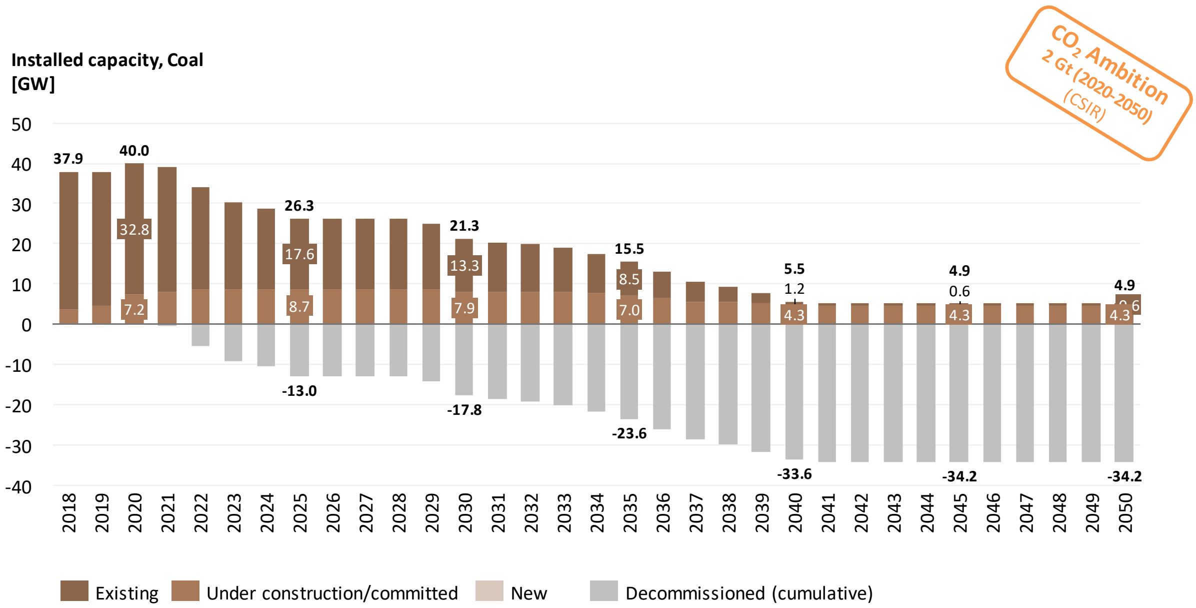
DG = Distributed Generation; PS = Pumped Storage;
NOTE: Energy share is a best estimate based on available data.
Sources: CSIR Energy Centre analysis

(b) Share (%)

Figure 70. Installed capacity and energy mix for the 2Gt CO_2 budget scenario from 2018-2050



(a) Existing, under construction and new coal capacity



(b) Existing, under construction and new coal capacity combined with cumulative decommissioned coal capacity

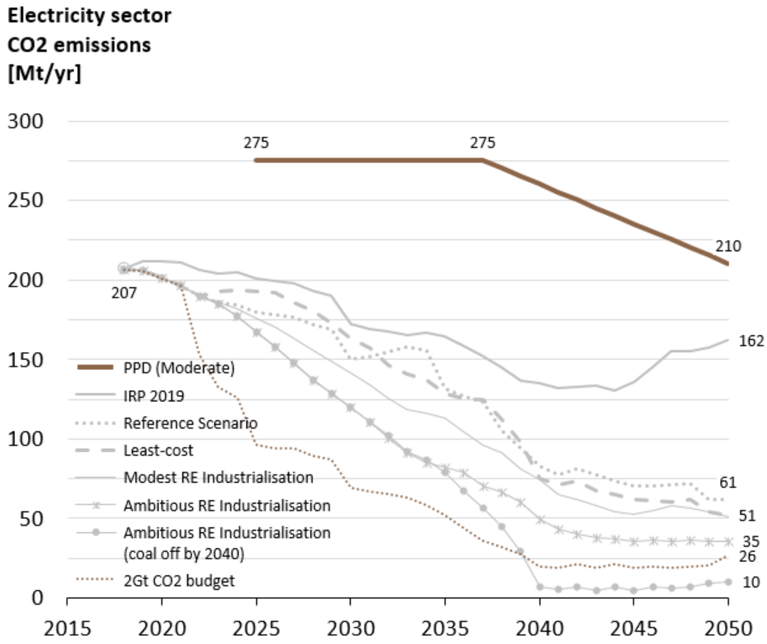
Figure 71. Existing, under construction and new coal capacity in the 2Gt CO_2 budget scenario

Electricity sector CO_2 emissions, water usage, SOx, NOx and particulate matter (PM) resulting from this scenario are shown in Figure 72 - Figure 74. The defined 2.0 Gt carbon budget constraint is adhered to for the 2020-2050 time horizon. This squeezing of electricity sector CO_2 emissions via the 2.0 Gt carbon budget results in a significant acceleration of coal fleet decommissioning as previously mentioned whilst also running the remaining existing coal capacity at lower capacity factors (average of ≈50% for 2018-2030 and ≈40% for 2031-2050). Even with such an ambitious CO_2 reduction constraint, clean coal technologies (specifically CCS and IGCC) do not form part of the least-cost energy mix. This is primarily as a result of their cost being prohibitively high relative to alternatives due to the cost premium of this technology.

Water usage is also significantly lower than other scenarios throughout the time horizon as existing coal capacity is decommissioned earlier than planned (50 year life) and remaining coal capacity runs at lower capacity factors.

SOx, NOx and particulate matter (PM) emissions show a similar trend to that of water usage with lower emissions across these emissions types throughout the time horizon.

The equivalent average wholesale electricity tariff for this scenario is shown in Figure 75. As expected, the equivalent wholesale tariff is higher than other scenarios up to 2035 whereafter reductions are realised as significant levels of solar PV and wind are deployed. The initially higher wholesale average tariff can be interpreted as the cost to decarbonize the power system early where most of the CO_2 volumes exist (pre-2035).

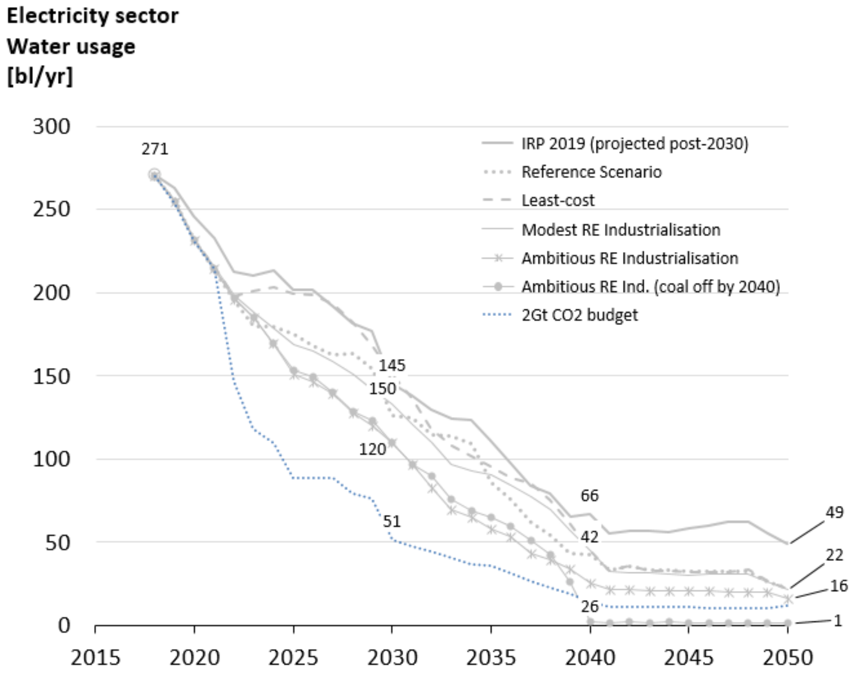


CO_2 emissions [Gt]
(2020-2050)

Constraints	
PPD (Moderate)	6.7
Outcomes	
IRP 2019	5.2
Reference Scenario	4.0
Least-cost	3.9
Modest RE Industrialisation	3.5
Ambitious RE Industrialisation	3.0
Ambitious RE Ind. (coal off 2040)	2.5
2Gt CO2 budget	2.0

Sources: DoE IRP 2019; CSIR analysis

Figure 72. Electricity sector CO_2 emission for the 2Gt CO_2 budget scenario



Sources: DMRE IRP 2019; CSIR analysis

Figure 73. Electricity sector water usage for the 2Gt CO_2 budget scenario

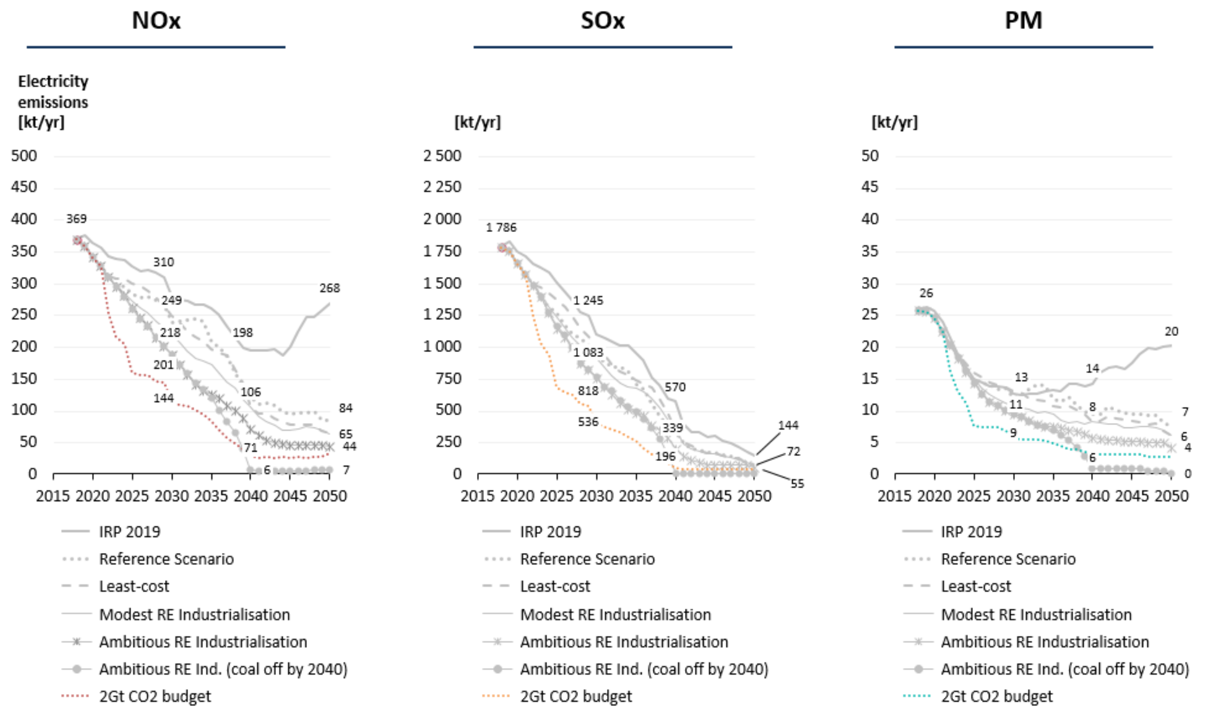
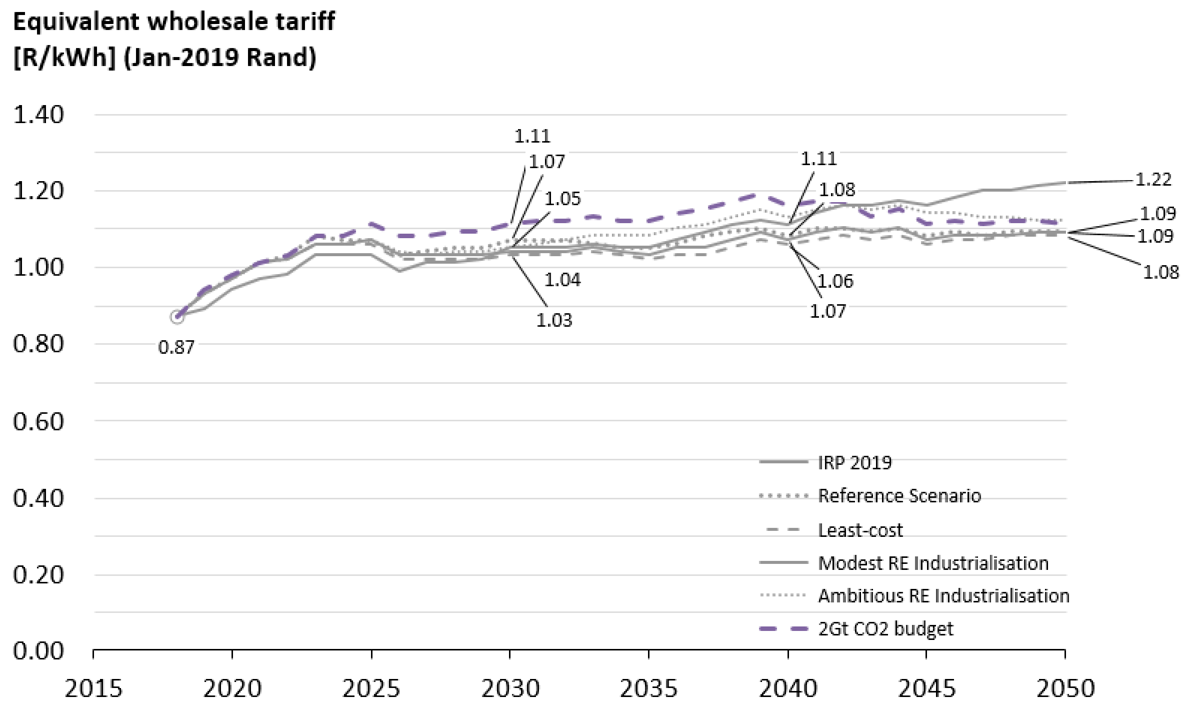


Figure 74. Electricity sector NOx, SOx and PM for the 2Gt CO_2 budget scenario



Notes: Transmission (Tx), distribution (Dx), system services (often referred to as ancillary services) and other costs not explicitly included in the PLEXOS modelling framework are approximated by a high level assumption of 0.20 R/kWh for all of these cost components consistently across all scenarios.
Sources: CSIR Energy Centre analysis

Figure 75. Equivalent average tariff for 2Gt CO_2 budget scenario

3.8 Synthesis

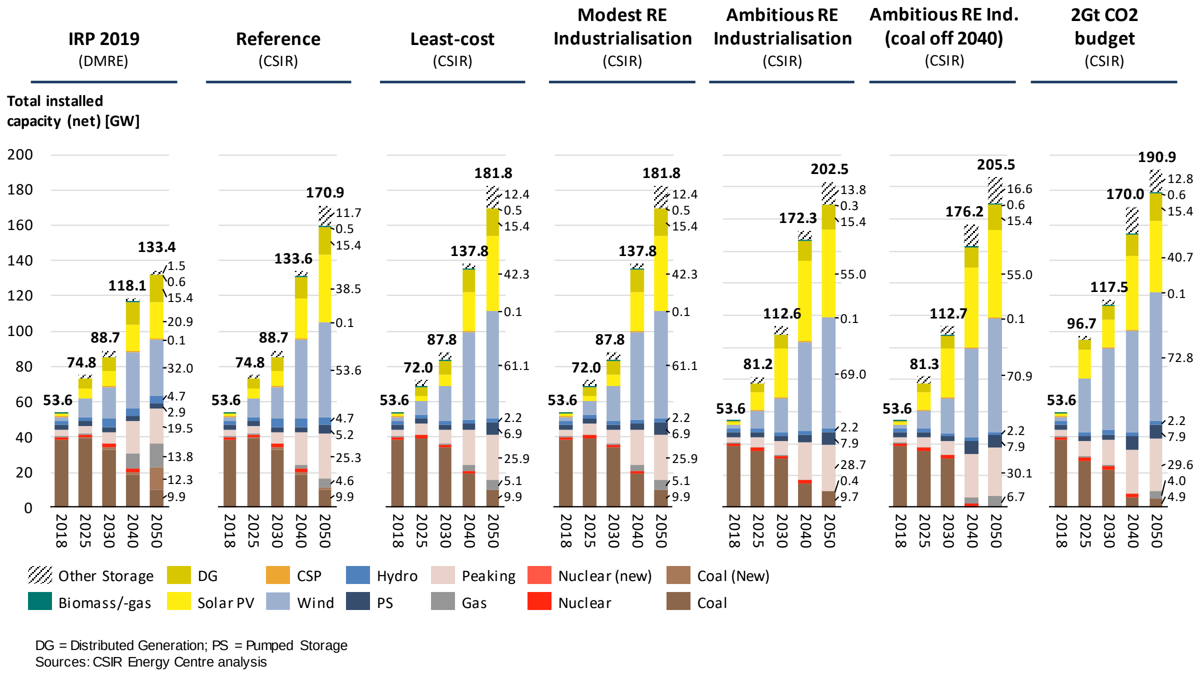
Total installed capacity and electricity production across all scenarios is shown in Figure 76 whilst the share of installed capacity and electricity production is shown Figure 77.

New-build coal capacity is only built when either forced-in (as part of the IRP 2019 and Reference scenarios) or when annual new-build constraints are placed on other technologies. Even when ambitious CO_2 reduction constraints are considered, clean coal technologies included as part of this study do not form part of the least-cost energy mix due to the cost premium of this technology.

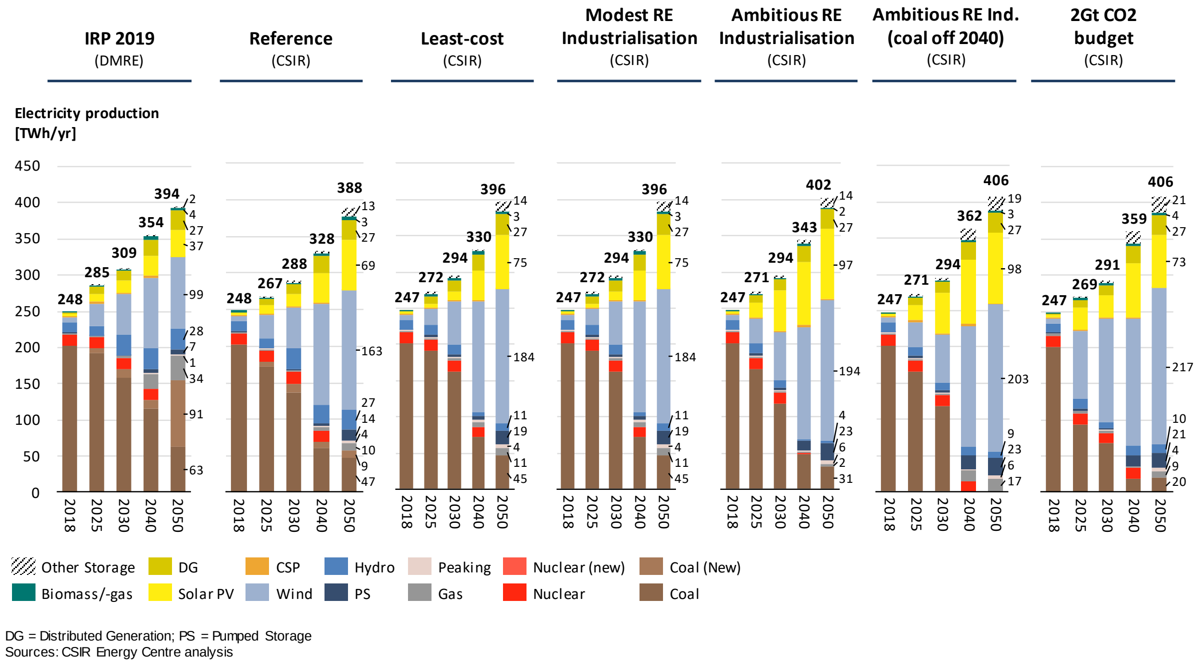
Across all scenarios, no new-build nuclear generation capacity is built as part of a least-cost energy mix. This may seem counterintuitive as the imperative for reduced CO_2 emissions is explored as part of this study. However, upon examining the techno-economic characteristics of new-build nuclear capacity (capital intensive), it becomes clear why it is not part of a least-cost energy mix in South Africa. The power system requires increased flexible and dispatchable capacity operating to provide system capacity but lower levels of energy dispatch (lower capacity factors) as variable renewable energy penetration levels increase. Thus, cheap to build and flexible capacity would be preferred in an optimised power system to supplement the already least-cost variable nature of capacity. The cost characteristics of nuclear capacity are exactly the opposite of this requirement (capital intensive). Thus, even though nuclear generation capacity can technically provide flexibility as has been demonstrated in a number of jurisdictions [40]–[43], it is not part of a least-cost mix into the future in South Africa.

New-build solar PV and wind capacity is consistently part of all scenarios albeit with different absolute deployment levels. The Modest and Ambitious RE Industrialisation scenarios aimed to smooth the wind and solar PV annual new build over the planning horizon. This is intended to represent a more sustainable and achievable build-out programme considering the already known outcomes from the Least-cost scenario.

The deployment of flexible and cheap to build generation capacity in the form of OCGTs/GEs and CCGTs/GEs is almost always consistently part of the energy mix. This capacity is fueled by natural gas and mostly dominated by peaking capacity (OCGTs/GEs) with some scenarios including CCGTs/GEs. Although significant capacity is deployed as flexible resources, they do not form a dominant part of the energy mix (only 1-5% by energy except in IRP 2019 with 9%). This is as a result of this capacity being utilized for capacity during exceptional periods to ensure sufficient system adequacy.

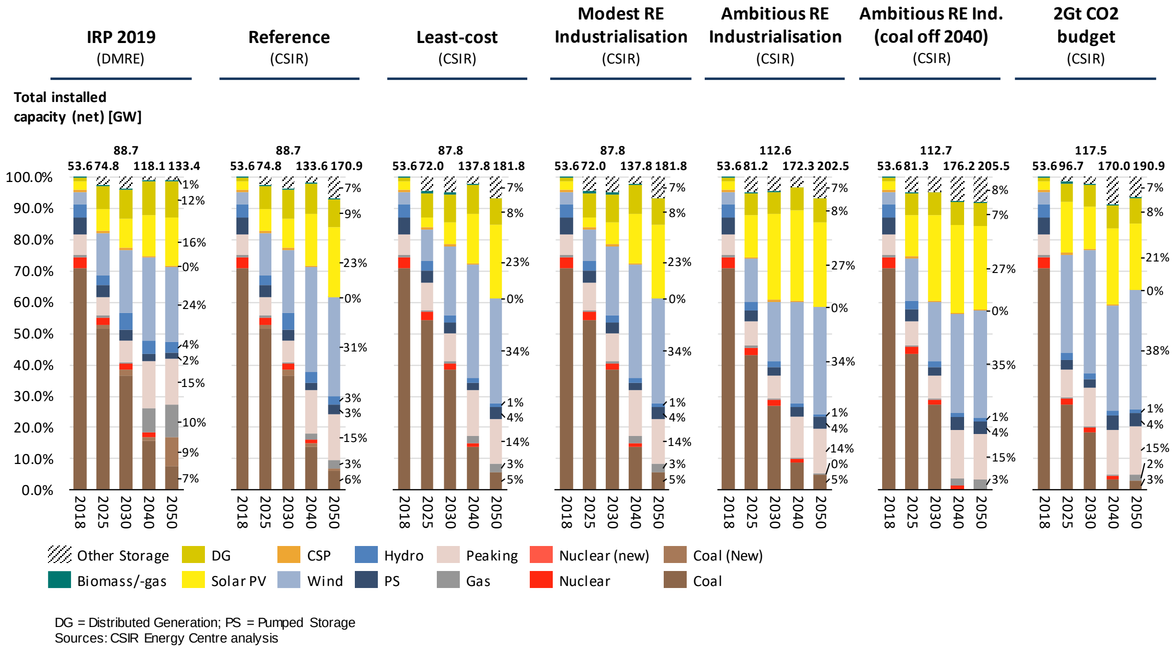


(a) Installed capacity (MW)

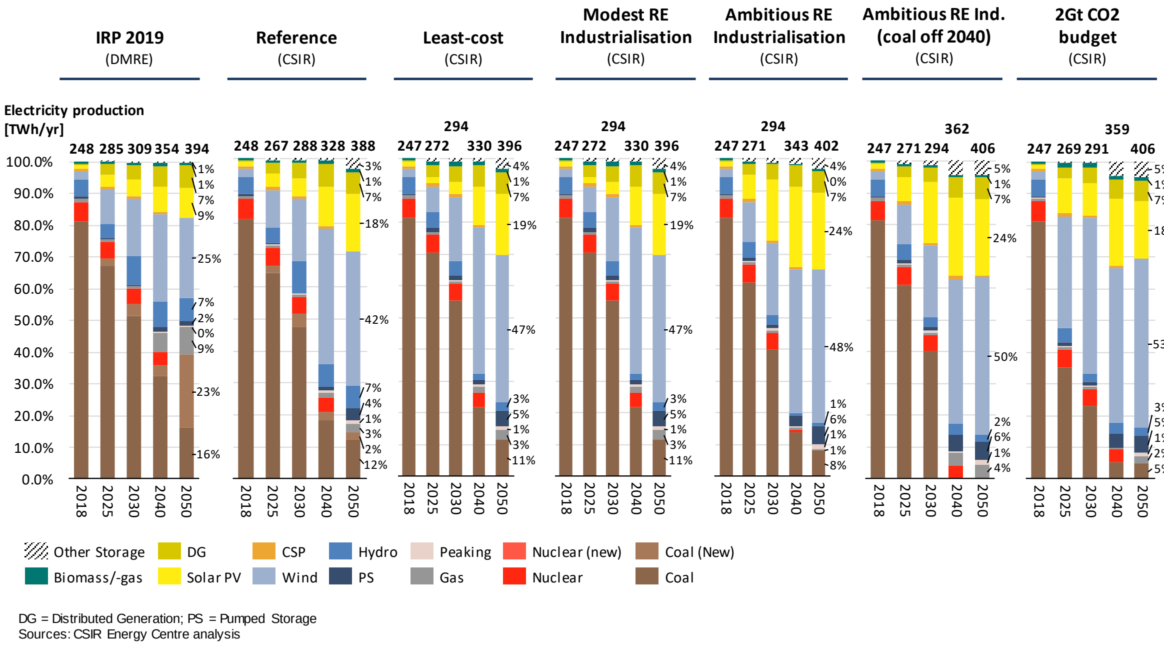


(a) Electricity production (TWh/yr)

Figure 76. Comparison of installed capacity and electricity production across range of scenarios



(a) Installed capacity share (%)



(b) Electricity production share (%)

Figure 77. Comparison of installed capacity and electricity production share across range of scenarios

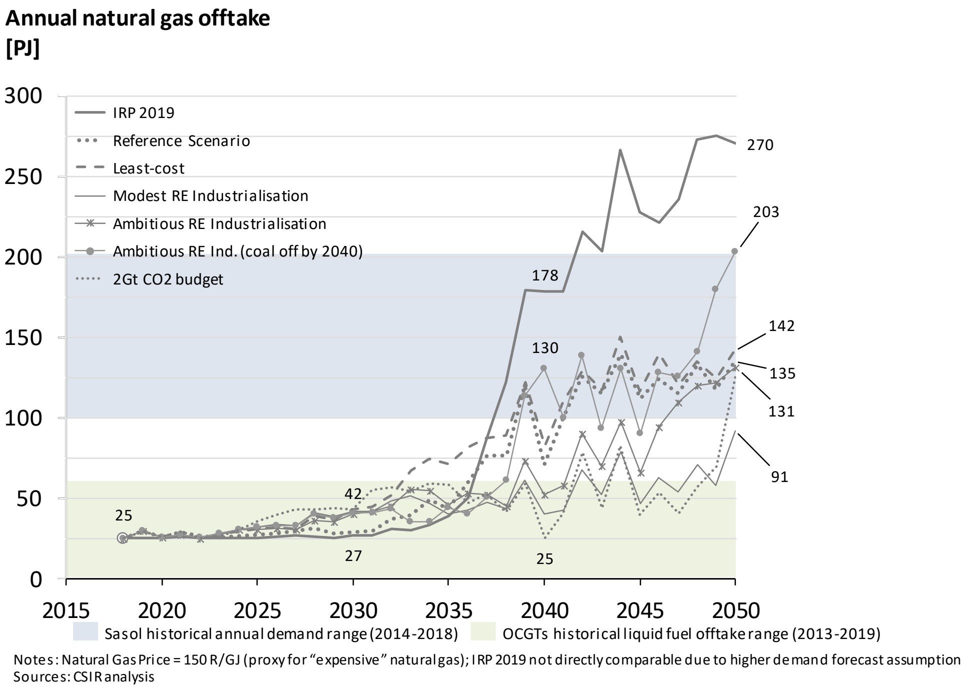
The absolute capacity of flexible natural gas-fired capacity built across scenarios is reduced relative to previous analyses undertaken by CSIR in this domain [44], [45] as increased levels of stationary storage is deployed as a result of adjusted cost trajectories for stationary storage. The stationary storage deployed is via both short duration battery storage throughout the time horizon (1-hour and 3-hour) and long-duration stationary storage in the form of pumped storage capacity towards the end of the time horizon (with the exception of the IRP 2019 scenario where no new-build pumped storage capacity is built). Additional pumped storage capacity is brought earlier across the scenarios as increased amounts of variable renewable energy are deployed and the existing coal fleet is decommissioned (range of 2035-2045 and 2.2-5.0 GW deployed).

Annual natural gas offtake expected in each scenario is shown in Figure 78. This includes existing natural gas demand at Sasol (electricity only) as well as new natural gas demand from new build capacity (based on relatively expensive natural gas described in section 2.3.3). Across all scenarios, the average annual capacity factor of the gas fleet is <30% whilst that of the peaking capacity utilizing natural gas is <5%. This finding is consistent with previous analyses conducted by CSIR [44], [45] which showed that with relatively expensive natural gas price assumptions, the demand for new gas capacity is mostly driven by flexible capacity requirements (not energy). For a relative comparison, Sasol's total natural gas demand (not just for electricity production) in 2018 was 102 PJ (relative to 102-202 PJ between 2014-2017) [46] whilst the current Mozambique-South Africa Sasol gas pipeline has a maximum capacity of 197 PJ per annum [47].

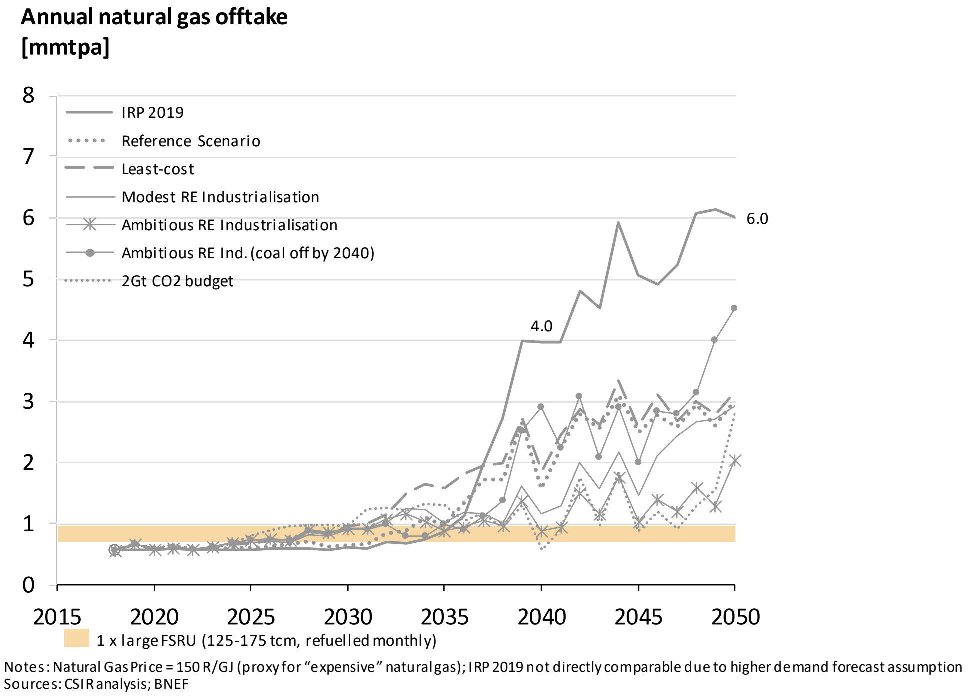
Annual natural gas demand is expected to remain relatively low, increasing from ≈25 PJ to ≈30-40 PJ by 2030. Thus, additional annual natural gas demand of ≈5-15 PJ is expected by 2030. With the exception of the IRP 2019, annual natural gas demand after 2030 begins to grow but only to ≈40-90 PJ by 2040 (≈15-65 PJ excluding Sasol) and ≈90-140 PJ by 2050 (≈65-115 PJ excluding Sasol).

The exception across these scenarios with respect to natural gas offtake is the scenario within which coal is decommissioned by 2040. This early decommissioning forces an increased annual demand for natural gas of up to ≈130 PJ by 2040 and ≈200 PJ by 2050.

In the IRP 2019, projections indicate that natural gas annual demand is expected to rise towards 180 PJ by 2040 (≈165 PJ excluding Sasol) and 270 PJ by 2050 (≈245 PJ excluding Sasol). The IRP 2019 scenario does represent a slightly higher demand forecast relative to other scenarios but a constrained deployment of new-build energy providers in the form of wind and solar PV (albeit variable) does drive the relative increased need for natural gas in the energy mix.



(a) Annual natural gas offtake for electricity - existing and new-build (PJ)

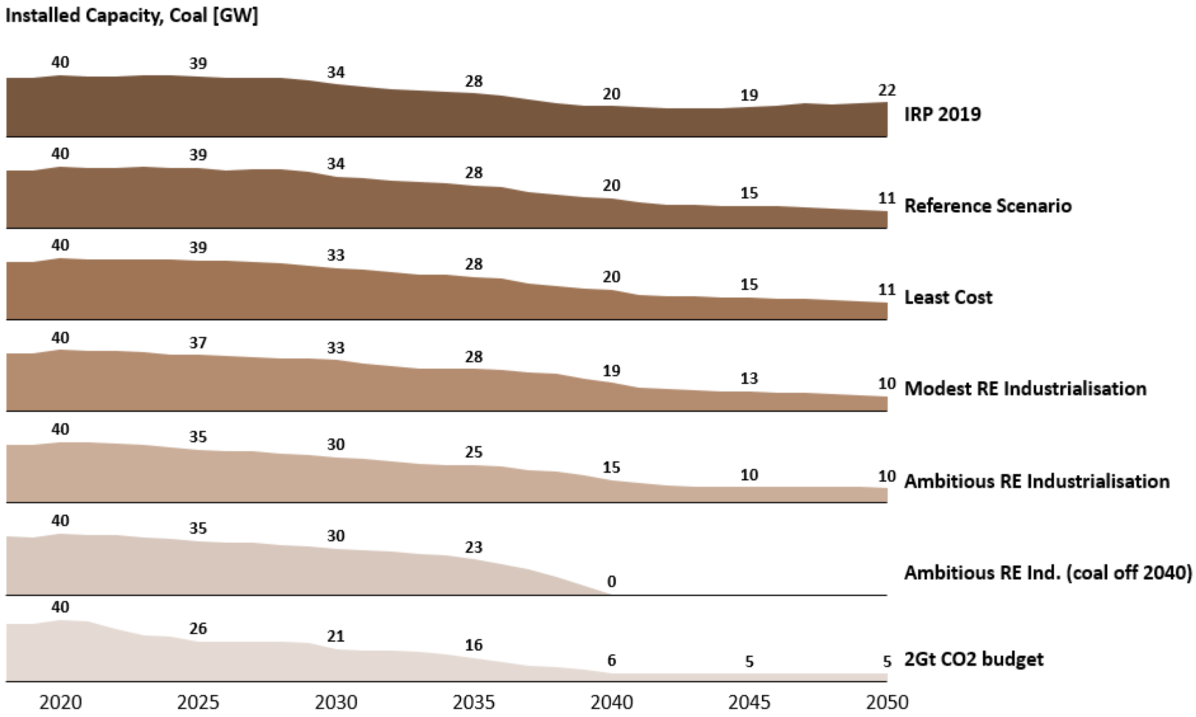


(b) Annual natural gas offtake for electricity - existing and new-build (mmtpa)

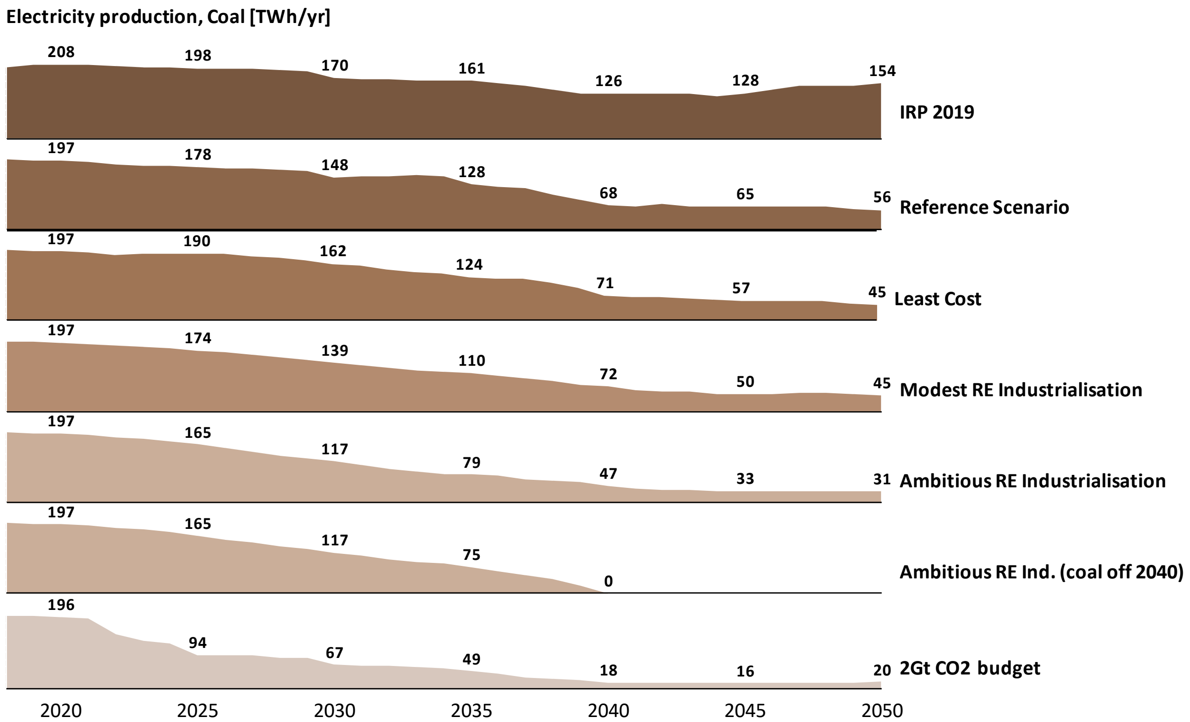
Figure 78. Natural gas offtake across range of scenarios considered

A focus on the installed coal capacity and electricity production across all scenarios is provided in Figure 79. Only the IRP 2019 scenario builds new coal capacity beyond 2030 as part of the optimal mix and this is driven by annual new-build limits on solar PV and wind being imposed throughout the time horizon. This is over and above the already committed 1.5 GW of coal capacity before 2030 included in the IRP 2019 and Reference scenario. The Reference scenario demonstrates how the removal of these annual new-build limits removes the need for new-build coal capacity. Only when a significantly ambitious renewable energy deployment (Ambitious RE Industrialisation scenario) or deep CO_2 emission reductions are pursued (coal off by 2040 and 2Gt CO_2 budget scenarios) does the existing coal capacity decommission notably earlier than planned 50 year life. However, existing coal fleet refurbishment costs to ensure a 50 year life of plant is attainable was not included in this analysis and could be substantial. These costs could influence the phasing and decommissioning schedules of the coal fleet.

The most ambitious CO_2 reduction scenarios explored in this analysis showed that coal, nuclear and CSP were not part of least-cost optimal energy mixes. With a particular focus on coal, even clean coal technologies included as expansion candidates (specifically coal with CCS and IGCC) do not form part of least-cost energy mixes. This is primarily as a result of their investment cost being prohibitively high (capital intensive). This can also be further appreciated when considering coal technology cost assumptions in Appendix A. New-build pulverised fuel (PF) and fluidized bed combustion (FBC) coal investment costs (the dominant cost) is ≈43 500-52 450 R/kW whilst coal PF with CCS is ≈R84 000 R/kW (in 2018) and ≈70 900 R/kW (by 2030). Thus, a cost premium of 1.93 (in 2018) and 1.63 (by 2030). Supplementing this information with the known expected future low utilization of the coal fleet (see Figure 80) as well as other cheaper to build energy and capacity expansion candidates, it is easy to appreciate why coal with CCS is not part of least-cost energy mixes as CO_2 ambition increases. Similarly, IGCC is very capital intensive (≈67 500 R/kW) revealing a similar reason as to why IGCC is also not part of least-cost energy mixes with increasing CO_2 ambition.



(a) Coal installed capacity (GW)



(b) Coal electricity production (TWh/yr)

Figure 79. Coal installed capacity and electricity production across range of scenarios considered

The capacity factor of the coal fleet (existing, under construction and new-build) is shown in Figure 80. The minimum capacity factor constraint placed on coal generation is clearly visible in a number of the scenarios. This is indicative of the need for increased flexibility from existing coal capacity as the low capacity factor constraint becomes binding (but does not always necessitate earlier than planned decommissioning – relative to 50-year life). Increased flexibility from the existing coal capacity can take the form of increased run-up/down rates, increased ramp-up/down rates, lower minimum stable levels and lower minimum up/down times.

Flexibility becomes increasingly important in scenarios where increased levels of solar PV and wind are integrated. This is especially notable in earlier years of the time horizon (pre-2030) as significant levels of coal capacity still exists and should be utilized as much as technically feasible but no more than economically optimal. The feasibility as well as cost implications of an increasingly flexibilised coal fleet will need to be carefully considered as increased variable renewable energy is deployed as part of the least-cost energy mix in South Africa.

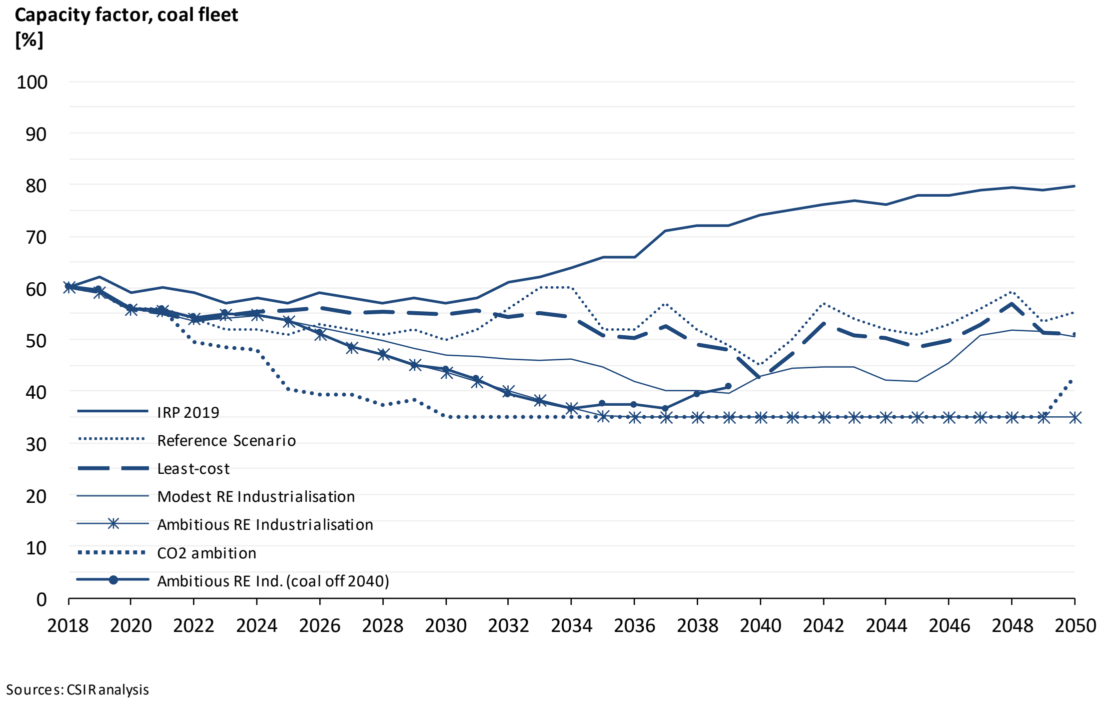


Figure 80. Capacity factor of coal fleet across range of scenarios considered

Water usage across all scenarios is compared in Figure 81 where it is clear that water usage is expected to decline across all scenarios. This is as a result of existing wet-cooled coal capacity being decommissioned whilst any new-build coal capacity is assumed to be dry-cooled. Dramatic declines in water usage before 2030 are visible in the 2Gt CO_2 budget scenario where water usage drops to ≈50 bl/yr relative to 120-150 bl/yr in all other scenarios by 2030. This is driven by the earlier than planned (50 year life) decommissioning of coal capacity in the 2Gt CO_2 budget scenario combined with the remaining coal capacity thereafter also running at lower capacity factors.

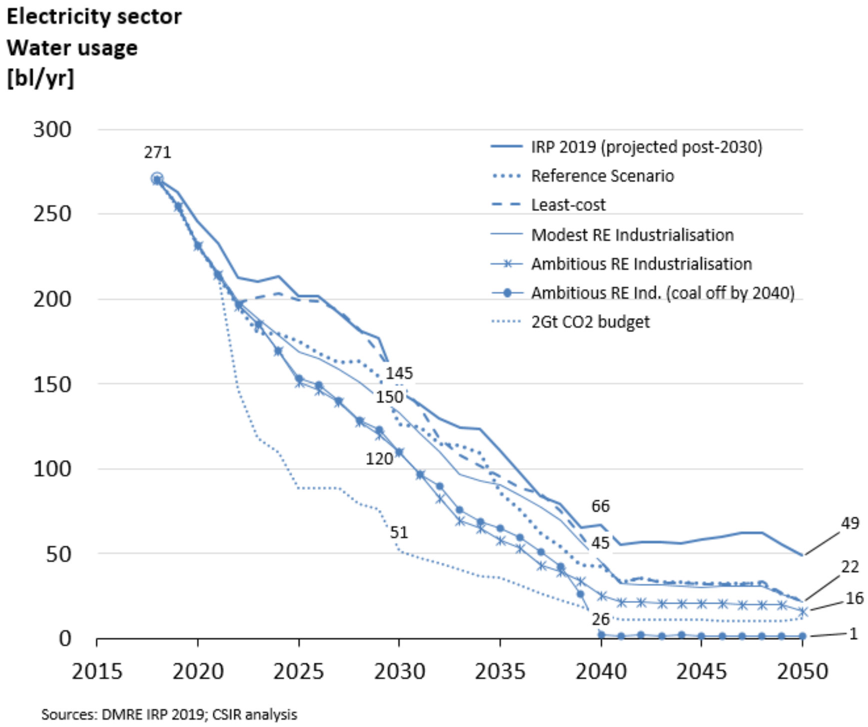
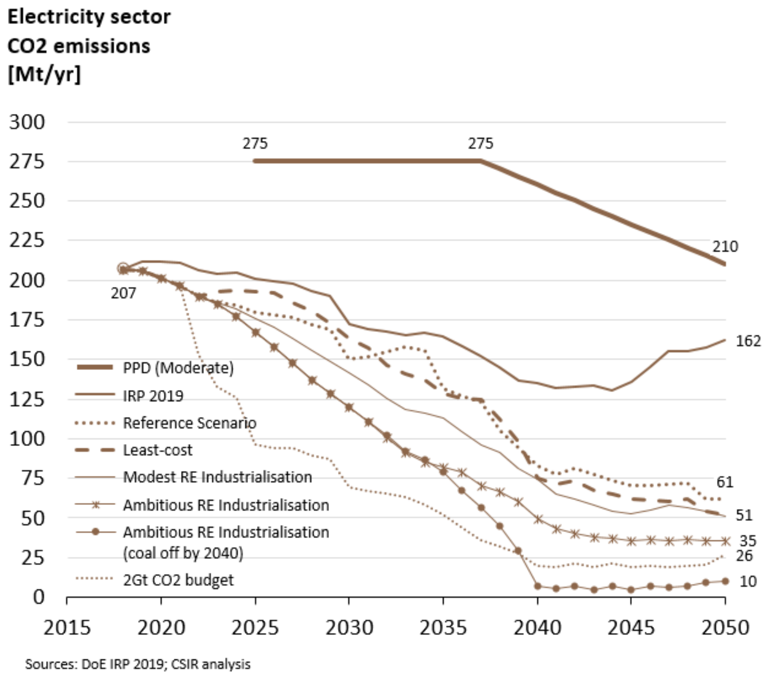


Figure 81. Power sector water usage across range of scenarios considered

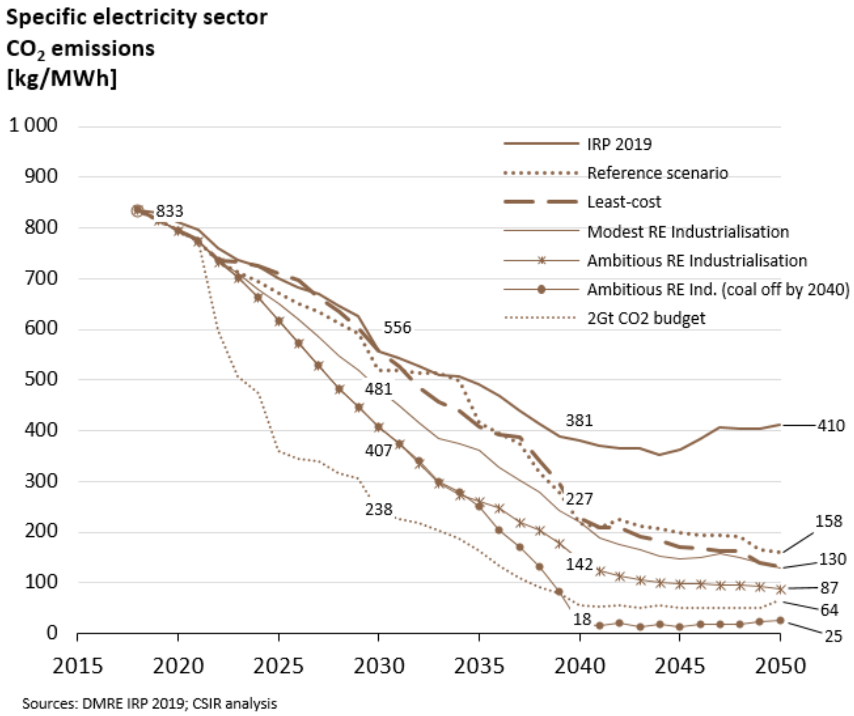
Absolute electricity sector CO_2 emissions (Mt/yr) as well as specific electricity sector CO_2 emissions ($kgCO_2$/MWh) are compared across scenarios in Figure 82 where it is clear that the PPD (Moderate) trajectory is never binding as all scenarios remain below this trajectory. A range of 2.0-5.2 Gt of power sector CO_2 emissions have been explored, with the IRP 2019 scenario being on the upper range (5.2 Gt) and the 2Gt CO_2 budget scenario being on the lower end (2.0 Gt). In all scenarios, power sector CO_2 emissions have already reached their peak and are expected to decline to ≈70-170 Mt by 2030 and ≈25-60 Mt by 2050 (with the exception of the IRP 2019 where CO_2 emissions are expected to be ≈160 Mt by 2050).



CO_2 emissions [Gt]
(2020-2050)

Constraints		
	PPD (Moderate)	6.7
Outcomes		
	IRP 2019	5.2
	Reference Scenario	4.0
	LC	3.9
	Modest RE Industrialisation	3.5
	Ambitious RE Industrialisation	3.0
	Ambitious RE Ind. (coal off 2040)	2.5
	2Gt CO2 budget	2.0

(a) Electricity sector CO_2 emissions (Mt/yr)



(b) Specific electricity sector CO_2 emissions (kg/MWh)

Figure 82. Power sector CO_2 emissions across range of scenarios considered

Electricity sector SOx, NOx and PM emissions are summarised in Figure 83 across all scenarios considered. As described in section 2.3.2.2, retrofitting of existing coal capacity for compliance with MES standards does allow for some level of reduced SOx, NO and PM emissions where these retrofits do happen and could be considered as a movement towards cleaner electricity production from coal. With the exception of the IRP 2019 scenario where new-build coal is built beyond 2030, it is clear that declines are expected across all of these emissions categories into the future. Increased NOx and PM emissions in the IRP 2019 scenario as a result of the post-2030 new-build coal capacity is clearly evident as the initial decline (as existing coal capacity decommissions) is reversed once new capacity is built post-2030. Without any coal capacity after 2040 in one of the scenarios, it is clear to see how minute SOx emissions and minimal annual volumes of NOx and PM are emitted (along with water usage being almost zero). The result of these findings is reduced localized air pollution and improved air quality for surrounding communities in close proximity to coal generation capacity as NOx and PM emissions are expected to decline.

The expected equivalent wholesale electricity tariff from the range of scenarios considered are compared in Figure 84 whilst total system costs are shown in Figure 85 (discounted for the period 2020-2050). The cost of power sector CO_2 ambitions is shown in Figure 86 where total discounted system cost over the time horizon relative to power sector CO_2 emissions is shown.

The Reference scenario is R 65 billion more expensive than Least-cost. The Ambitious RE Industrialisation and 2 Gt CO_2 budget scenarios are expected to be R 96 billion and R 189 billion more expensive than Least-cost over the time horizon. Similarly, these scenarios are also expected to be R 31 billion (+1%) and R 124 billion (+3.5%) more expensive than the Reference scenario. Hence, even when imposing an earlier than least-cost optimal or smoothed renewable energy build out program or when an ambitious power sector CO_2 constraint is considered, CO_2 emissions mitigation comes at very little relative increase in costs.

It is also clear from Figure 85 that coal plays a dominant role in total system costs ranging from 30-44% of total system costs (whether via existing fuel and operations & maintenance costs or new-build capital costs). The relatively small contribution to total system cost of the flexible gas-fired capacity built is also evident (4-6%). The implicit assumption that costs excluded from the analysis are captured consistently across scenarios at ≈19% of total system costs is also visible (see section 2.1.3).

The cost of power sector CO_2 ambition is shown in Figure 86 where a non-linear trend is evident but the expected increase in system costs as CO_2 emissions reduce is clear. However, a more interesting finding is that the cost to decarbonize the power sector in South Africa is not as steep as expected. An increase of only 3.5% (R124-billion) enables a move from 4.0 Gt (Reference scenario) to 2.0 Gt (CO_2 Ambition scenario) over the time horizon. Similarly, as an intermediate step, to move from 4.0 Gt (Reference scenario) towards 3.5 Gt (Modest RE Industrialisation) would actually save costs with a system costs reduction of 1.1% (R39-billion) whilst a further move towards 3.0 Gt (Ambitious RE Industrialisation) would only result in an increase in systems costs of 1% (R31-59 billion).

It is important to note that these findings are also consistently conservative with respect to the relative cost comparisons across scenarios. This is as a result of the asymmetrical nature of cost assumptions made where costs for technologies not yet part of the existing energy mix being made quite conservative i.e. costs for stationary storage, solar PV and wind could be significantly cheaper. If further cost reductions beyond those expected are realised, the scenarios where more of these technologies are deployed would become cheaper whilst others would get slightly cheaper but with a lower sensitivity to further cost reductions (IRP 2019 and Reference scenario).

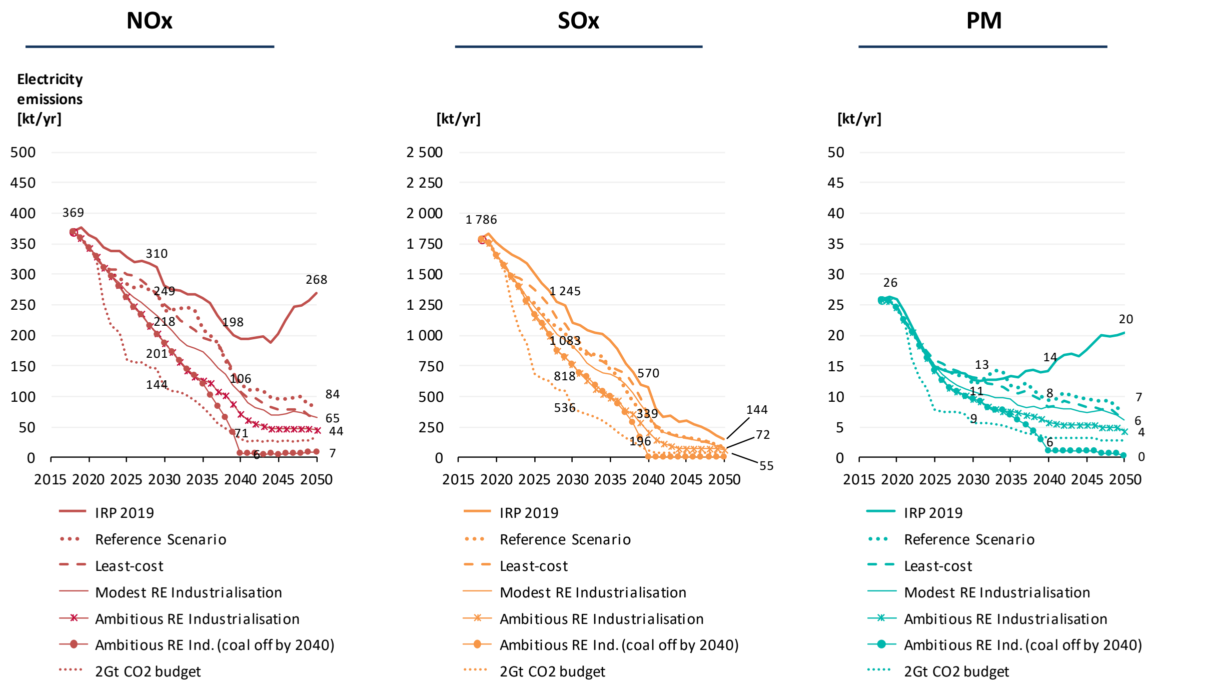
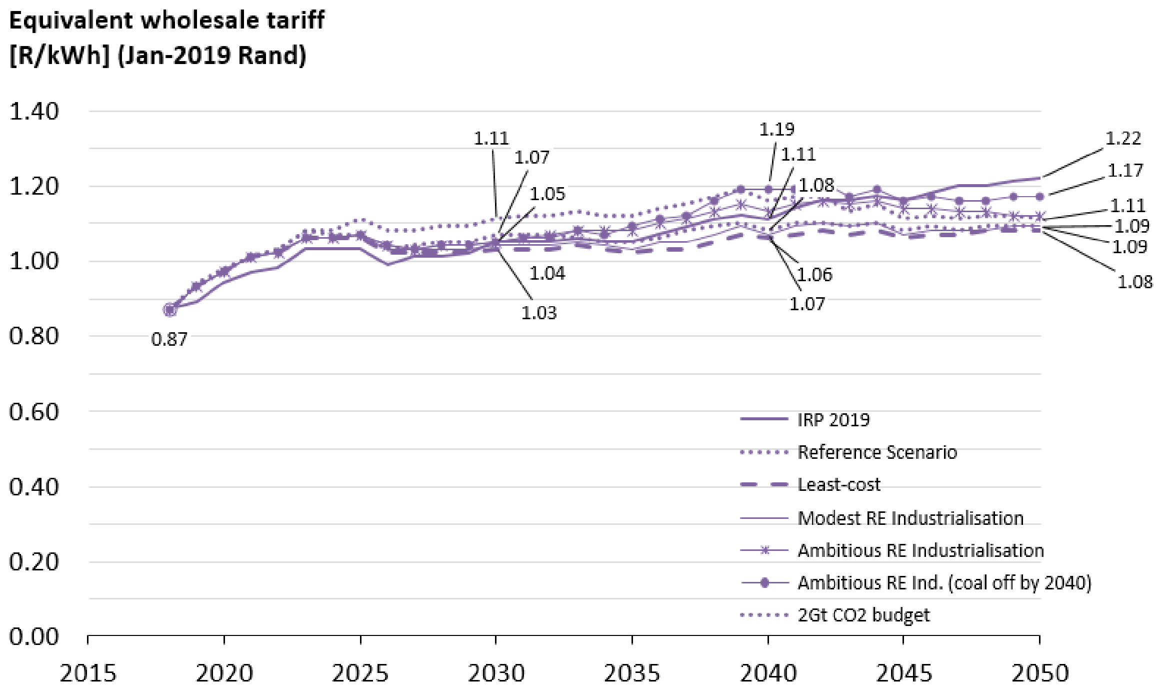
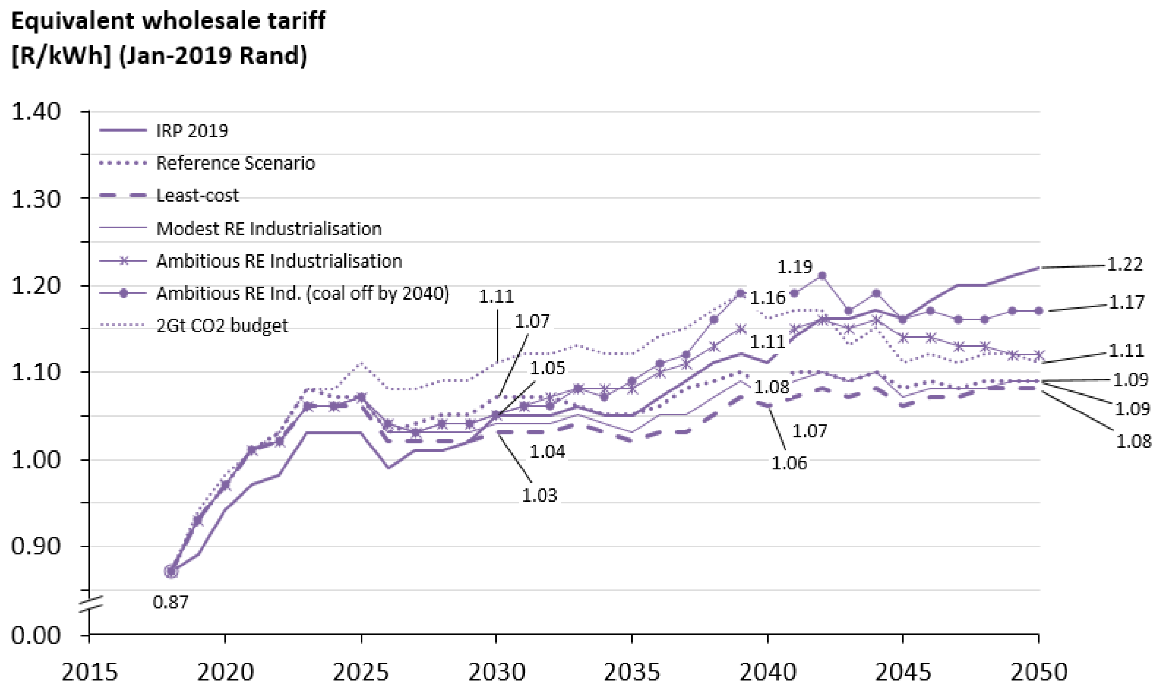


Figure 83. Electricity sector NOx, SOx and PM across range of scenarios considered



Notes: Transmission (Tx), distribution (Dx), system services (often referred to as ancillary services) and other costs not explicitly included in the PLEXOS modelling framework are approximated by a high level assumption of 0.20 R/kWh for all of these cost components consistently across all scenarios.
Sources: CSIR Energy Centre analysis

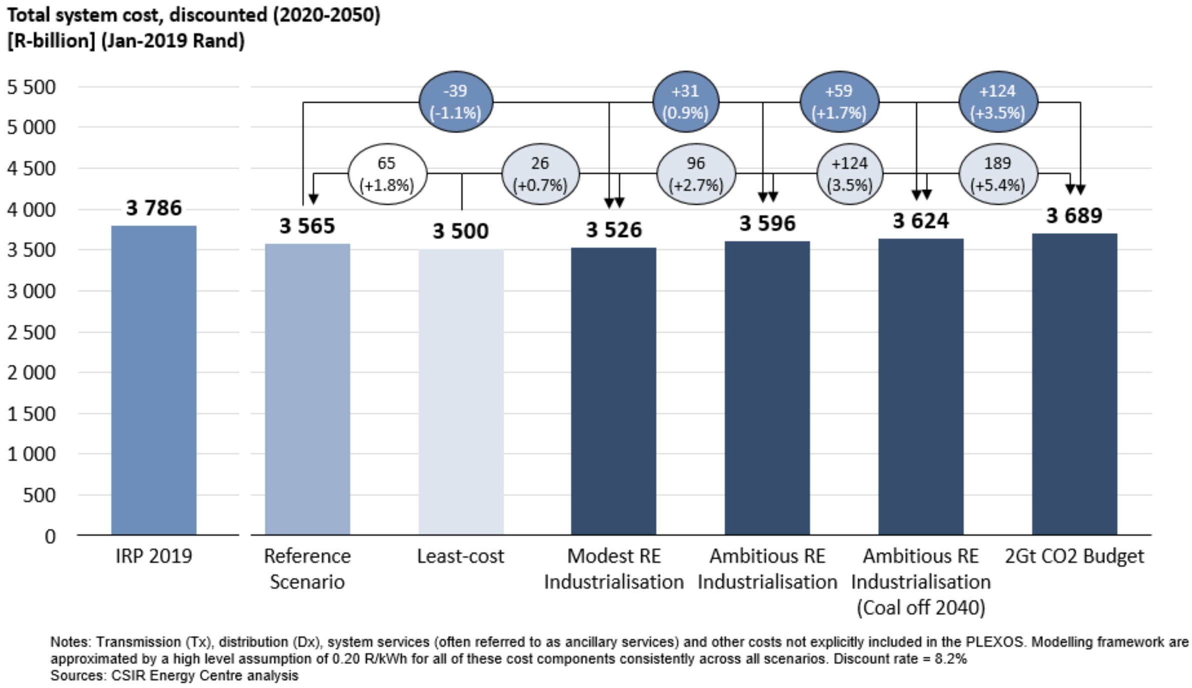
(a) Equivalent wholesale tariff



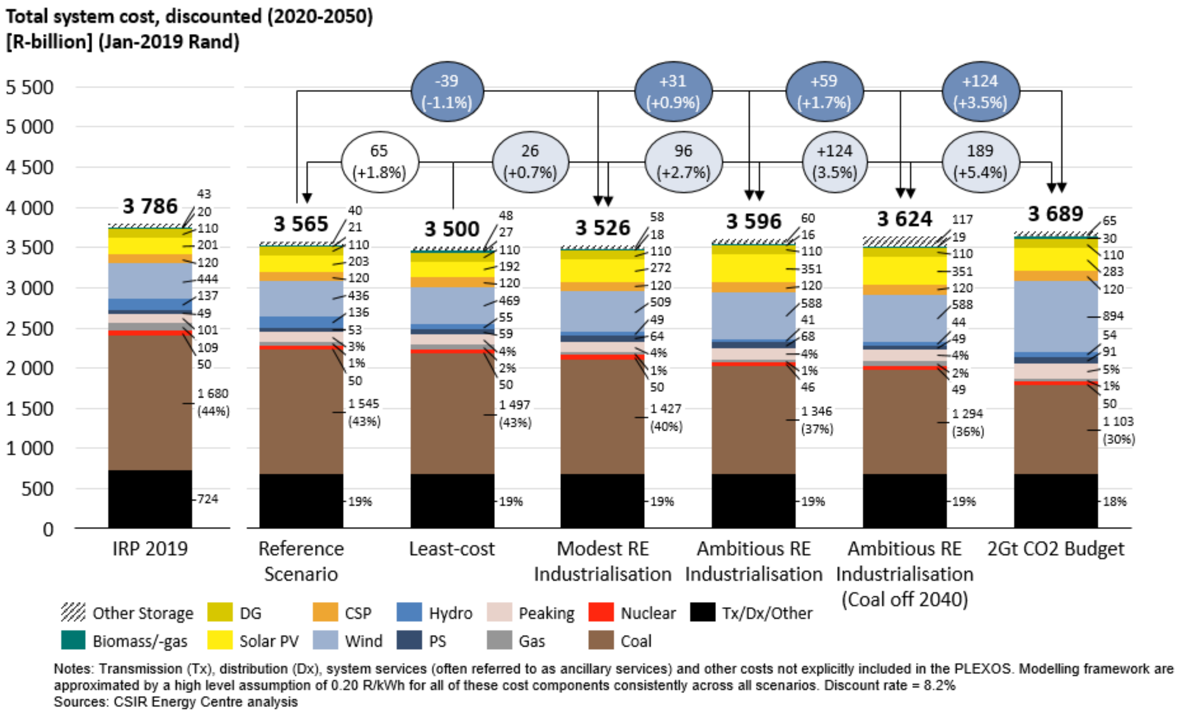
Notes: Transmission (Tx), distribution (Dx), system services (often referred to as ancillary services) and other costs not explicitly included in the PLEXOS modelling framework are approximated by a high level assumption of 0.20 R/kWh for all of these cost components consistently across all scenarios.
Sources: CSIR Energy Centre analysis

(b) Equivalent wholesale tariff (zoomed)

Figure 84. Equivalent average tariff across range of scenarios considered

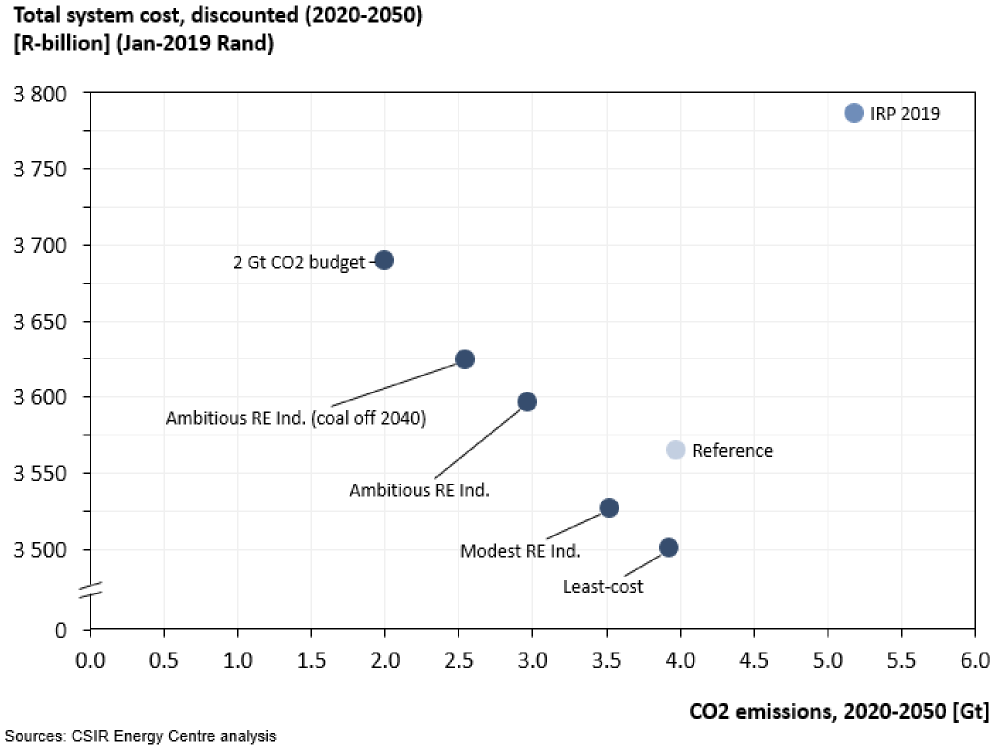


(a) Discounted total system cost

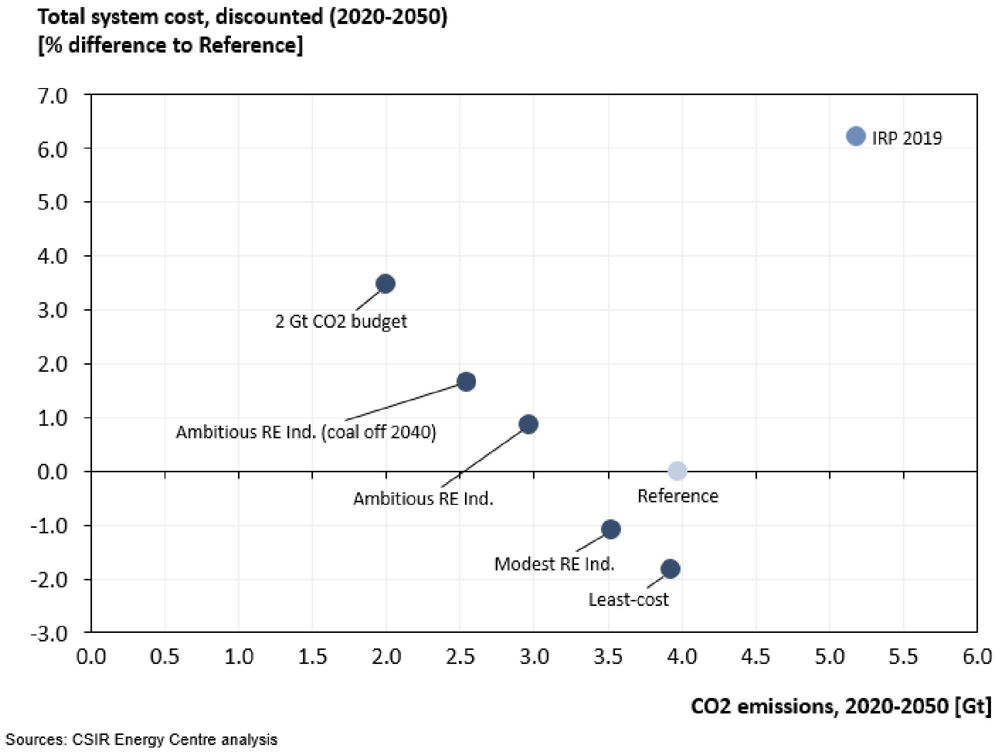


(b) Discounted total system cost (breakdown by technology)

Figure 85. Total system cost (discounted) and equivalent wholesale tariff (discounted) for 2020-2050 across range of scenarios considered



(a) Discounted total system cost (R-billion)



(b) Discounted total system cost (% difference relative to Reference)

Figure 86. Cost of power sector CO_2 ambitions in South Africa

4 Brief assessment of Covid-19 impact

During the course of this study, the outbreak of a novel coronavirus began in Hubei, a city in Wuhan Province of China in December 2019. This severe acute respiratory syndrome coronavirus 2 (SARS-CoV-2) causes coronavirus disease 2019 (Covid-19). South Africa's first imported case of Covid-19 was on 5 March 2020 whilst at almost the same time (by 11 March 2020), the World Health Organisation (WHO) declared Covid-19 a global pandemic [48]. Soon thereafter, by 26 March 2020, South Africa entered into a national lockdown and started implementing a risk adjusted strategy incorporating 5 alert levels [49]. By 14 July 2020, globally recorded Covid-19 cases was over 13-million with daily new cases averaging more than 200 00 cases and total known deaths just over 550 000 whilst South Africa had recorded 276 242 cases with deaths due to Covid-19 reaching 4 079 [50], [51].

One of the primary impacts of the national lockdown is significantly reduced electricity demand to an unprecedented extent. Globally, countries that went into similar lockdowns (35% of the global population) experienced average weekly reduced electricity demand of more than 20% whilst overall energy demand reductions of 25% have been seen [52]. For 2020 calendar year, the IEA expects reductions in global demand for coal (-8%), oil (-9%) and electricity (-5%) as global energy demand overall reduces by 6% [52]. This would be the largest reduction in global energy demand in 70 years and seven times larger than the impact of the 2008/09 global financial crisis.

The South African hourly residual demand profile from 23 March 2020 to 3 July 2020 is shown in Figure 87 [53] whilst the 2020 weekly residual demand is shown in Figure 88 [54]. Peak residual demand dropped by up to 11.0 GW during L5[12] (average 5.7 GW), by 8.7 GW during L4 (average 3.3 GW) and 7.3 GW during L3 lockdown conditions (average 0.9 GW). During the 5 weeks of L5 lockdown, a 23-26% reduction in weekly energy demand occurred relative to expectations at the beginning of 2020. Similarly, energy demand up to beginning July 2020 dropped by 10.5 TWh from 64.5 TWh to 54.0 TWh (-16%). For 2020, Eskom expects electricity demand to contract by 13.6 TWh (-6.2%) in 2020 depending on the extent to which there is repeated enforcement of higher levels of lockdown as a response to Covid-19.

As the economy began re-opening notably in L3, the return of electrical demand was near immediate and expectations are that weekly deviations will be lower than 5% by August 2020 already. This shows the acute and transient nature of the national lockdown on electricity demand. Thus, although demand is expected to be significantly lower in 2020, demand is expected to return towards the levels assumed as part of this study very soon (as taken from the MTSAO 2019) [27] albeit adjusted for the

[12] L5 = Level 5 of the national lockdown

absolute reduction expected during 2020). This effect had already been seen by early July 2020 as the return of electrical demand resulted in Eskom having to resort to rotational load shedding again [5].

For 2020, the IEA estimates a reduction in global CO_2 emissions of ≈8% relative to 2019 translating into 2.6 Gt less CO_2 emissions [52]. For perspective, across all scenarios considered in this study, the entire power sector CO_2 emissions for 2020-2050 is 2.0-5.2 Gt. Although not yet quantified, South African CO_2 emissions are expected to follow a similar downward trend in 2020 as a result of the national lockdown but this is not envisioned to be structural as electricity, mobility and heating/cooling energy demand returns in 2021 and beyond.

A range of other impacts are expected in the power sector but will not be extensively addressed here. Amongst others, these would include [55]:

- Increased focus on ensuring the health and safety of the workforce.
- Resource availability to ensure essential services can be provided (system operations and maintenance).
- A shifted demand profile towards residential demand as a significant component of the workforce has begun to work remotely which could become structural whilst also stressing existing distribution network infrastructure (away from commercial demand).
- Supply chain disruptions for maintaining existing network infrastructure and power stations as well as those which are under construction and planned. These are expected to reduce post Covid-19 but it is unclear when this will be the case and should be strongly considered as a key risk to implementation of large-scale under construction and new-build electricity infrastructure.

Concern has also been raised around the risk of an extended global recession affecting innovation and funding of clean energy technologies in the short-term and long-term [56]. However, long-term effects would highly depend on the speed of bringing the pandemic under control. A longer duration pandemic will result in structural changes in behavior mostly affecting energy demand in mobility and buildings whilst other effects could include reduced investment in niche clean energy technologies required for long-term CO_2 ambitions trajectories. The deferral of new investments in clean energy and related research as a result of expected economic recessions could see the reduced emissions during 2020 quickly outweighed in a very short time period thereafter.

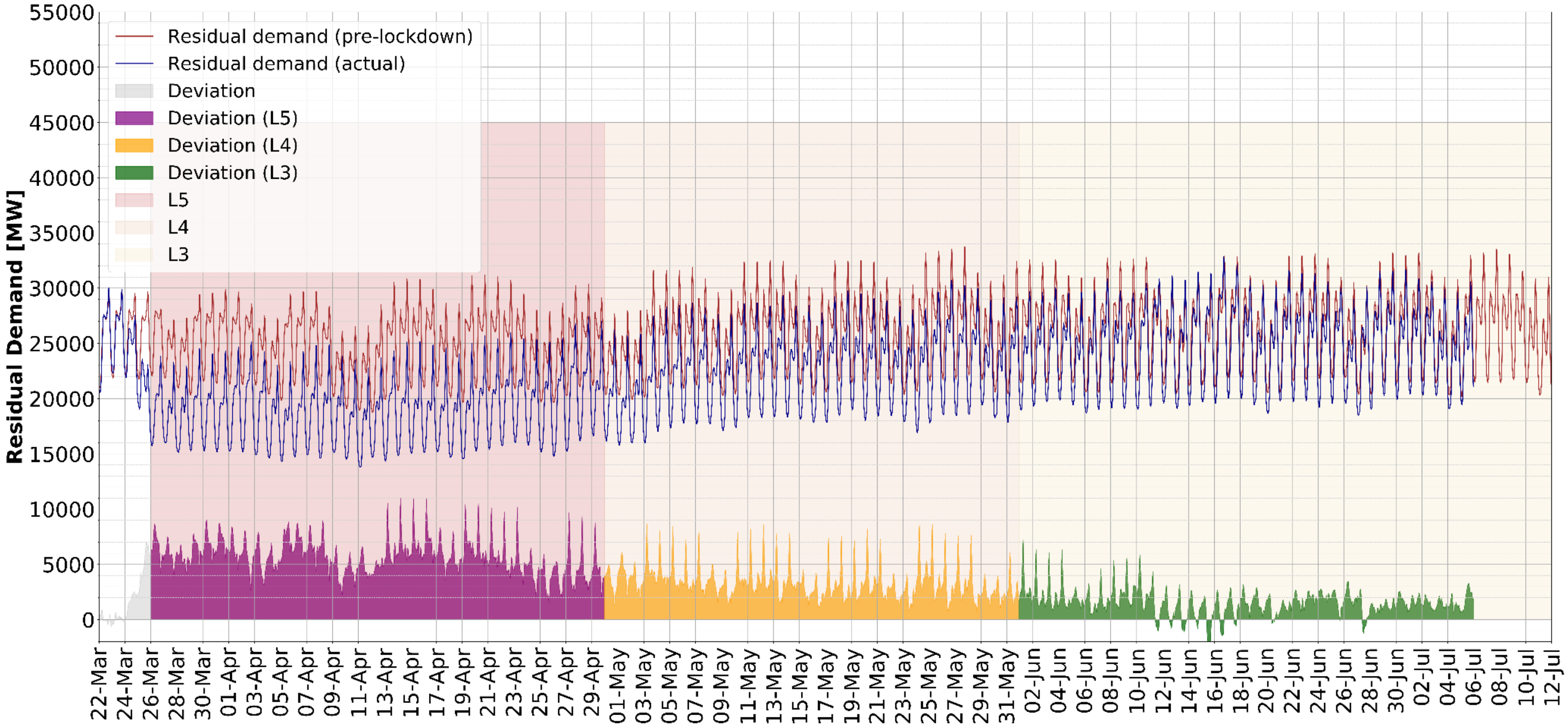
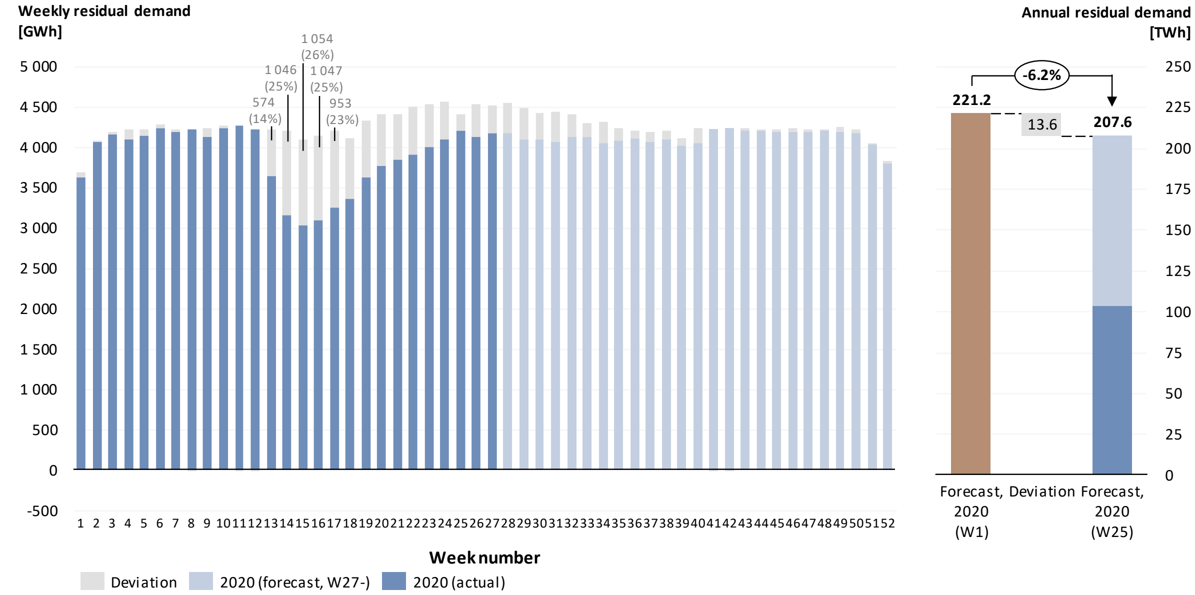


Figure 87. Hourly residual demand (23 March 2020 – 7 July 2020) highlighting the effect of the South African national lockdown on hourly electricity demand



Sources: Eskom; CSIR Energy Centre analysis

Figure 88. Weekly residual electricity demand for 2020 highlighting the effect of the South African national lockdown (deviations during Level 5 highlighted)

5 Summary and conclusions

The South African power system is in a crisis with urgent action required to ensure system adequacy whilst simultaneously ensuring a cleaner and more diversified energy mix

Following historical periods of supply-demand imbalance over more than 10 years, 2019 and the first half of 2020 have seen the most intensive load shedding thusfar with ≈1.3 TWh and ≈1.2 TWh of load shed respectively. Instantaneously - up to 6000 MW was shed in 2019 and 4000 MW thusfar in 2020. This has been driven by a combination of factors including delayed commissioning and underperformance of new-build coal generation capacity at Medupi and Kusile as well as the degradation of the existing Eskom coal fleet energy availability factor (EAF) declining from ≈94% in 2002 to 67% in 2019.

A systems level approach utilizing long-term capacity expansion planning and optimisation has been applied incorporating all major cost drivers

Utilising a high temporal resolution systems level approach in a modelling tool widely applied globally and in South Africa (PLEXOS), a range of scenarios are explored extracting scenario specific outputs across important dimensions. These dimensions include capacity and dispatch of existing generators, timing of new power generators, CO_2 emissions, other emissions (NOx, SOx and PM), water usage and total system costs.

The IRP 2019 time horizon is expanded beyond 2030 to 2050 where it is found that a large portion of the existing coal fleet is re-built but a more diversified energy mix is expected

The IRP 2019 represents current policy where first new build capacity (beyond short-term emergency options) occurs in 2022 and consists of 1.6 GW of wind, 1.0 GW of solar PV and 0.5 GW of stationary storage. New coal capacity (0.75 GW) is planned for 2023 (and another 0.75 GW by 2027) as per DMRE policy adjustment process, followed by 1.0 GW of new gas capacity in 2024 (and further gas capacity from 2027 onwards). Imported hydro-based electricity of 2.5 GW from Inga is also included in 2030. After 2030, annual new-build limits on solar PV and wind combined with a non-ambitious CO_2 constraint, result in 12.3 GW of new coal capacity being built by 2050 (driving increased CO_2 emissions). Gas-fired capacity operated as peaking capacity is built pre-2030 (3.9 GW of OCGTs/GEs) whilst considerable mid-merit capacity and further peaking capacity is built thereafter (6.0 GW CCGT/GEs and 21.7 GW OCGT/GEs).

A Reference scenario considers an updated demand forecast and EAF expectation more aligned with the latest information whilst also removing annual new-build constraints

As in the IRP 2019 scenario, new build capacity was forced in as per current policy to 2030 where after the least-cost new build mix consists of solar PV, wind, storage and natural gas-fired capacity, with no further coal capacity being built. New-build storage capacity is dominated by short duration battery storage and only late in the time horizon is additional pumped storage built. Reductions of CO_2, NOx, SOx and PM emissions are observed as the existing coal fleets decommissions and is mostly replaced by renewable energy.

The South African electrical energy mix is currently 81% coal but is expected to diversify as a least-cost future comprises 55% coal by 2030 and 11% coal by 2050

It is least-cost to shift from a coal dominated energy mix to an increasingly diversified energy mix made up of 55% coal by 2030 and 11% coal by 2050. The least-cost new build mix consists of solar PV, wind, storage and natural gas fired capacity supported by an existing fleet of generation capacity including coal, nuclear and imports. It is least-cost to have a 41% carbon-free (36% renewables) energy mix by 2030 and 76% carbon-free (76% renewables) by 2050. Other already existing zero-carbon energy providers which would decommission over the time horizon include nuclear, CSP and biomass/-gas.

Regardless of CO_2 ambition, renewable energy is expected to play an increasingly important role whilst other new-build low-carbon energy providers like nuclear, CSP and coal (with CCS) are not part of the least-cost energy mix

Across all scenarios, in order to meet increasingly ambitious power sector CO_2 mitigation in South Africa, wind and solar PV technologies play a dominant role. By 2030, these technologies are expected to comprise 29-64% of the energy mix depending on CO_2 ambition whilst by 2050 the energy mix would be 67-81% solar PV and wind. This means solar PV and wind installed capacity of ≈15-40 GW and ≈20-45 GW by 2030. By 2050, installed capacity of wind and solar PV is expected range from ≈30-75 GW and ≈35-70 GW respectively. Regardless of CO_2 ambition level, no new-build nuclear, coal (with/without CCS) or CSP capacity are part of least-cost optimal energy mixes.

The role of coal-fired power stations is expected to shift towards providing flexibility in a future South African power system with increased variable renewable energy part of the energy mix

Flexibility becomes increasingly important in scenarios where increased levels of solar PV and wind are integrated. This is especially notable in earlier years of the time horizon (pre-2030) as significant levels of coal capacity still exists and should be utilized as much as technically feasible but no more than economically optimal. The finding that individual coal plants are utilized at very low capacity factors suggests opportunity for medium to long-term strategic decision-making to save costs. The feasibility as well as cost implications of an increasingly flexibilised coal fleet to operate at low capacity factors will need to be carefully considered as increased variable renewable energy is integrated.

With increasing CO_2 ambition, system costs increase but not as much as initially expected –clearing a path for power sector decarbonization with minimal tradeoffs and substantial power sector benefits

The total discounted system cost for an Ambitious RE Industrialisation scenario with 3.5 Gt of CO_2 emissions (for 2020-2050) is R 9-11-billion more than the Reference whilst a 2.0 Gt CO_2 budget scenario cost R 75-billion more. This represents a less than 3% increase in total system cost for substantial CO_2 mitigation gains of 0.4 Gt and 1.9 Gt of CO_2 respectively. Hence, even when imposing an earlier than optimal and smoothed renewable energy build out program or when an ambitious power sector CO_2 constraint is considered, CO_2 emissions mitigation comes at a relatively small premium. Furthermore, conservative technology costs assumed for renewable energy technologies further strengthens this finding in scenarios with increased levels of CO_2 ambition and resulting renewable energy penetration.

The South African electrical energy mix is currently 81% coal but is expected to diversify as a least-cost future comprises 55% coal by 2030 and 11% coal by 2050

It is least-cost to shift from a coal dominated energy mix to an increasingly diversified energy mix made up of 55% coal by 2030 and 11% coal by 2050. The least-cost new build mix consists of solar PV, wind, storage and natural gas fired capacity supported by an existing fleet of generation capacity including coal, nuclear and imports. It is least-cost to have a 41% carbon-free (36% renewables) energy mix by 2030 and 76% carbon-free (76% renewables) by 2050. Other already existing zero-carbon energy providers which would decommission over the time horizon include nuclear, CSP and biomass/-gas.

Gas-fired generation capacity is considered as a proxy for an increased need for flexible capacity but limited energy provision

The absolute capacity of flexible natural gas-fired capacity built across scenarios is reduced relative to previous analyses undertaken by CSIR in this domain as increased levels of stationary storage is deployed. The average annual capacity factor of the gas fleet is <30% across all scenarios whilst that of peaking capacity utilizing natural gas is <5%. Thus, demand for new gas capacity is mostly driven by flexible capacity requirements (not energy). Annual natural gas offtake is expected to remain relatively low, increasing from ≈25 PJ to ≈30-40 PJ by 2030 (additional annual natural gas demand of ≈5-15 PJ). Thereafter, increased natural gas offtake of ≈40-90 PJ by 2040 (≈15-65 PJ excluding Sasol) and ≈90-140 PJ by 2050 (≈65-115 PJ excluding Sasol). An exception is when all coal capacity is decommissioned by 2040 forcing an increased annual natural gas offtake of up to ≈130 PJ by 2040 and ≈200 PJ by 2050. Similarly, in the IRP 2019 scenario, projections indicate natural gas annual offtake is expected to rise towards 180 PJ by 2040 (≈165 PJ excluding Sasol) and 270 PJ by 2050 (≈245 PJ excluding Sasol).

Water usage in the power sector across scenarios is expected to continually decline with all new technologies being deployed exhibiting low water intensity

Water usage in the power sector is expected to drop significantly in all scenarios even when new-build coal capacity is built in the IRP 2019. This trend is expected as a result of new-build coal capacity being assumed to be dry-cooled and the least-cost technology mix consisting of renewable energy, storage and gas-fired capacity with relatively low water usage. In a scenario where all coal capacity is decommissioned by 2040, water usage becomes negligible from 2040 onwards whilst other scenarios water usage is expected to drop from ≈270 bl/yr in 2018 to ≈120-150 bl/yr by 2030, ≈25-65 bl/yr by 2040 and ≈15-50 bl/yr by 2050.

Other power sector emissions (NOx, SOx and PM) reduce rapidly across most scenarios, with potential immediate emissions air quality impact for local communities

With the exception of the IRP 2019 scenario where further new-build coal is built after 2030, NOx and PM emissions are expected to decline significantly as the existing coal fleet decommissions. SOx emissions decline across all scenarios as a result of any new-build coal being assumed to be fitted with FGD. The result of these findings is reduced localized air pollution and improved air quality for surrounding communities in close proximity to coal generation capacity as NOx and PM emissions are expected to decline.

The impact of the South African national lockdown to mitigate Covid-19 on the South African electricity sector has been wide-ranging but largely seen as acute reduced demand which quickly returned resulting in the return of load shedding

A novel coronavirus outbreak in Wuhan Province of China occurred in December 2019 called severe acute respiratory syndrome coronavirus 2 (SARS-CoV-2) which causes coronavirus disease 2019 (Covid-19). In response, South Africa enforced a national lockdown with a risk-adjusted strategy from 27 March 2020. One of the impacts of this is substantially reduced electricity demand. During Level 5 (5 weeks), a 23-26% weekly demand reduction occurred whilst energy demand to 7 July 2020 dropped by 10.5 TWh (-16%). For 2020, expectations are for demand to contract by 14 TWh (-6.2%). As the economy began re-opening in Level 3, electrical demand returned near immediately revealing the acute and transient effect of the lockdown on demand. This has also already manifested in July 2020 as Eskom again resorted to rotational load shedding.

This study has provided insights on a range of dimensions including cost, energy mix, water use and emissions from more ambitious CO_2 mitigation in the South African power system. To further enhance value, additional (but not exhaustive) research on a number of topics is suggested

Whether planned or accelerated coal fleet decommissioning occurs, further analysis on the socio-economic impact of these scenarios would prove valuable as a contribution to the ongoing just transition discussion and planning currently underway in South Africa. This would include energy sector specific transition opportunities (especially with increased ambition on renewable energy deployment) as well as economy-wide interventions required to plan for the expected shifting economic activities in regions where coal capacity is decommissioned.

The scale of power sector infrastructure deployment including renewable energy (solar PV and wind) was well as gas-fired capacity, storage and network infrastructure could spur an opportunity for increased localisation of supply chains. The necessary scale of investment and consistency required to justify increased levels of localisation and resulting industrialisation should be further investigated to enable increased economic benefits for South Africa and potential export markets into Southern Africa and Sub-Saharan Africa.

Future electricity demand is still uncertain in South Africa as previous forecasts have not been realised. Although previous research has shown that the demand forecast would only change the pace and scale of investment, it would not change the energy mix i.e. new-build capacity is always comprised of solar PV, wind, natural gas fired capacity and storage [31], [57]–[60]. A finding of this study has been that with increasing CO_2 ambitions, it becomes more about how fast South Africa can deploy the least-cost mix dominated by solar PV and wind. In the context of this uncertainty, additional research into the impact of a more accurate or range of expected demand forecasts is necessary.

Refurbishment costs for the existing South African coal fleet was not included in this study. These costs could be substantial but are currently unknown. Large refurbishment costs at individual coal units or coal stations will influence timing of coal capacity decommissioning (if not at 50-year life) and should be investigated for specific coal power stations if information is made available.

There is a requirement to better understand transmission grid infrastructure required to enable the substantial new supply capacity expected across all scenarios that would mostly be located in very different locations relative to existing supply capacity. Existing processes plan periodically to integrate official IRP 2019 new supply capacity including the Transmission Development Plan (TDP) [61] and Strategic Grid Plan (SGP) [62] within Eskom. Other processes led by the Department of Environment, Forestry and Fisheries (DEFF) include Strategic Environmental Assessments (SEAs) to streamline EIA processes for investments in electricity grid infrastructure, renewable energy development and gas network infrastructure. However, an improved understanding of the expected locations of supply capacity across scenarios in this study (as well as others) will allow for improved utilisation of existing network infrastructure and as much as possible appropriate and well timed network investments.

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Appendix A Technology cost assumptions

Table 6. IRP 2019 technology cost assumptions (conventional technologies) [6]

Property			Conventionals							
			Coal (PF)	Coal (FBC)	Coal (PF with CCS)	Coal (IGCC)	Nuclear (DoE)	OCGT	CCGT	CC-ICE
Rated capacity (net)		*[MW]*	4 500	250	4 500	644	1 600	132	732	230
Overnight cost per capacity	*2019*	*[ZAR/kW]*	43 453	52 450	84 054	67 454	75 728	10 015	10 997	10 833
Construction time		*[a]*	9	4	9	4	6	2	3	1
Capital cost (calculated)[1]	*2019*	*[ZAR/kW]*	48 188	58 023	90 632	74 622	93 964	10 754	12 199	10 833
	2030	*[ZAR/kW]*	48 188	58 023	76 435	74 622	91 968	10 754	12 199	10 833
	2050	*[ZAR/kW]*	48 188	58 023	76 435	74 622	91 968	10 754	12 199	10 833
Fuel cost		*[ZAR/GJ]*	34	17	34	34	10	147	147	147
Heat rate		*[GJ/kWh]*	9 812	10 788	14 106	9 758	10 657	11 519	7 395	7 300
Fixed O&M		*[ZAR/kW/a]*	1 133	762	1 932	1 743	1 187	196	203	183
Variable O&M		*[ZAR/MWh]*	98	212	181	92	45	3	27	80
Load factor (typical)		*[./.]*	85%	85%	85%	85%	90%	8%	36%	55%
Economic lifetime		*[a]*	30	30	30	30	60	30	30	30
			2%		2%					
			6%		6%					
			13%		13%					
			17%		17%		15%			
Capital phasing		[%/a]	17%		17%		15%			
			16%	10%	16%	10%	25%			
			15%	25%	15%	25%	25%		40%	
			11%	45%	11%	45%	10%	90%	50%	
			3%	20%	3%	20%	10%	10%	10%	100%

[1] *From capital phasing, discount rate and economic lifetime.*
All costs in Jan-2019 Rands

Table 7. IRP 2019 technology cost assumptions (renewable technologies) [6]

Property			Renewables														
			Wind	**Solar PV (tracking)**	**Solar PV (fixed)**	**CPV**	**CSP (trough, 3h)**	**CSP (trough, 9h)**	**CSP (tower, 3h)**	**CSP (tower, 9h)**	**Biomass (forestry)**	**Biomass (MSW)**	**Landfill Gas**	**Biogas**	**Bagasse (Felixton)**	**Bagasse (gen)**	**Inga**
Rated capacity (net)		*[MW]*	100	10	10	10	125	125	125	125	25	25	5	5	49	53	2 500
Overnight cost per capacity	*2019*	*[ZAR/kW]*	15 016	16 371	15 582	61 724	105 988	160 519	94 574	63 862	61 945	175 224	19 468	94 700	19 700	37 768	50 156
Construction time		*[a]*	4	2	1	1	4	4	4	4	4	4	1	1	2	3	8
Capital cost (calculated)[1]	*2019*	*[ZAR/kW]*	14 652	15 845	9 937	61 724	103 649	156 976	92 487	62 453	68 527	193 842	19 468	94 700	20 233	39 342	74 340
	2025	*[ZAR/kW]*	12 708	14 030	8 619	61 724	101 386	153 548	90 467	61 089	68 527	193 842	19 468	94 700	20 233	39 342	74 340
	2030-2050	*[ZAR/kW]*	12 708	14 030	8 619	61 724	101 714	154 046	90 760	61 287	68 527	193 842	19 468	94 700	20 233	39 342	74 340
Fuel cost		*[ZAR/GJ]*	-	-	-	-	-	-	-	-	39	-	-	-	90	90	-
Heat rate		*[GJ/kWh]*	-	-	-	-	-	-	-	-	14 243	18 991	12 302	11 999	26 874	19 327	-
Fixed O&M		*[ZAR/kW/a]*	742	347	328	384	1 253	1 320	1 153	1 236	2 028	7 927	2 907	2 378	190	431	484
Variable O&M		*[ZAR/MWh]*	-	-	-	-	1	1	1	1	81	140	76	62	10	30	0
Load factor (typical)		*[./.]*	36%	25%	20%	22%	32%	46%	38%	60%	85%	85%	74%	85%	55%	50%	67%
Economic lifetime		*[a]*	20	25	25	25	30	30	30	30	30	30	30	30	30	30	60
																	20%
																	25%
																	25%
Capital phasing		*[%/a]*															10%
			5%				10%	10%	10%	10%	10%	10%					5%
			5%				25%	25%	25%	25%	25%	25%				10%	5%
			10%	10%			45%	45%	45%	45%	45%	45%			33%	30%	5%
			80%	90%	100%	100%	20%	20%	20%	20%	20%	20%	100%	100%	67%	60%	5%

[1] From capital phasing, discount rate and economic lifetime
All costs in Jan-2019 Rands

Table 8. IRP 2019 technology cost assumptions (stationary storage) [6]

Property			Storage technologies			
			Pumped Storage	**Battery (Li-Ion, 1h)**	**Battery (Li-Ion, 3h)**	**CAES (8h)**
Rated capacity (net)		*[MW]*	333	3	3	180
Overnight cost per capacity	*2019*	*[ZAR/kW]*	24 680	12 119	29 777	30 009
	2030-2050	*[ZAR/kW]*	24 680	5 757	14 144	30 009
Construction time		*[a]*	8	1	1	4
Capital cost (calculated)[1]	*2019*	*[ZAR/kW]*	30 777	11 141	27 372	33 906
	2030-2050	*[ZAR/kW]*	30 777	5 757	14 144	33 906
Fuel cost		*[ZAR/GJ]*	-	-	-	147
Heat rate		*[GJ/kWh]*	-	-	-	4 465
Round-trip efficiency		*[%]*	78%	89%	89%	81%
Fixed O&M		*[ZAR/kW/a]*	222	757	757	261
Variable O&M		*[ZAR/MWh]*	0	4	4	3
Load factor (typical)		*[./.]*	33%	4%	12%	22%
Economic lifetime		*[a]*	50	10	10	40
			1%			
			1%			
			2%			
			9%			
Capital phasing		*[%/a]*	16%			
			22%			25%
			24%			25%
			20%			25%
			5%	100%	100%	25%

All costs in Jan-2019 Rands

[1] *From capital phasing, discount rate and economic lifetime.*

Table 9. CSIR technology cost assumptions (renewable technologies) [6]

Property			Renewables													
			Wind	**Solar PV (tracking)**	**Solar PV (fixed)**	**CPV**	**CSP (trough, 3h)**	**CSP (trough, 9h)**	**CSP (tower, 3h)**	**CSP (tower, 9h)**	**Biomass (forestry)**	**Biomass (MSW)**	**Landfill Gas**	**Biogas**	**Bagasse (Felixton)**	**Bagasse (gen)**
Rated capacity (net)		*[MW]*	100	10	10	10	125	125	125	125	25	25	5	5	49	53
Overnight cost per capacity	*2019*	*[ZAR/kW]*	14 514	14 031	10 140	61 724	105 988	160 519	159 546	110 576	47 645	175 224	19 468	94 700	19 700	37 768
Construction time		*[a]*	4	2	1	1	4	4	4	4	4	4	1	1	2	3
Capital cost (calculated)[1]	*2019*	*[ZAR/kW]*	14 691	12 202	8 746	61 724	103 649	156 976	168 877	117 044	52 708	193 842	19 468	94 700	20 233	39 342
	2025	*[ZAR/kW]*	13 131	9 307	6 671	61 724	101 386	153 548	132 771	92 019	52 708	193 842	19 468	94 700	20 233	39 342
	2030	*[ZAR/kW]*	11 831	7 165	5 136	61 724	101 714	154 046	114 230	79 169	52 708	193 842	19 468	94 700	20 233	39 342
	2040	*[ZAR/kW]*	10 544	5 363	3 844	61 724	101 714	154 046	97 535	67 598	52 708	193 842	19 468	94 700	20 233	39 342
	2050	*[ZAR/kW]*	9 238	4 517	3 238	61 724	101 714	154 046	92 382	64 027	52 708	193 842	19 468	94 700	20 233	39 342
Fuel cost		*[ZAR/GJ]*	-	-	-	-	-	-	-	-	36	-	-	-	90	90
Heat rate		*[GJ/kWh]*	-	-	-	-	-	-	-	-	12 386	18 991	12 302	11 999	26 874	19 327
Fixed O&M		*[ZAR/kW/a]*	742	347	328	384	1 253	1 320	1 153	1 236	2 028	7 927	2 907	2 378	190	431
Variable O&M		*[ZAR/MWh]*					1	1	1	1	81	140	76	62	10	30
Load factor (typical)		*[./.]*	36%	25%	20%	22%	32%	46%	38%	60%	85%	85%	74%	85%	55%	50%
Economic lifetime		*[a]*	20	25	25	25	30	30	30	30	30	30	30	30	30	30
Capital phasing		*[%/a]*														
			5%				10%	10%	10%	10%	10%	10%				
			5%				25%	25%	25%	25%	25%	25%				10%
			10%	10%			45%	45%	45%	45%	45%	45%			33%	30%
			80%	90%	100%	100%	20%	20%	20%	20%	20%	20%	100%	100%	67%	60%

[1] From capital phasing, discount rate and economic lifetime
All costs in Jan-2019 Rands

Table 10. CSIR technology cost assumptions(stationary storage) [6]

Property			Storage technologies			
			Pumped Storage	**Battery (Li-Ion, 1h)**	**Battery (Li-Ion, 3h)**	**CAES (8h)**
Rated capacity (net)		*[MW]*	333	3	3	180
Overnight cost per capacity	*2019*	*[ZAR/kW]*	24 680	5 000	12 286	30 009
Construction time		*[a]*	8	1	1	4
Capital cost (calculated)[1]	*2019*	*[ZAR/kW]*	30 777	5 000	12 286	33 906
	2025	*[ZAR/kW]*	30 777	3 495	8 588	33 906
	2030	*[ZAR/kW]*	30 777	2 927	7 192	33 906
	2040	*[ZAR/kW]*	30 777	2 561	6 293	33 906
	2050	*[ZAR/kW]*	30 777	2 196	5 394	33 906
Fuel cost		*[ZAR/GJ]*				147
Heat rate		*[GJ/kWh]*				4 465
Round-trip efficiency		*[%]*	78%	89%	89%	81%
Fixed O&M		*[ZAR/kW/a]*	222	757	757	261
Variable O&M		*[ZAR/MWh]*	0	4	4	3
Load factor (typical)		*[./.]*	33%	4%	12%	22%
Economic lifetime		*[a]*	50	10	10	40
			1%			
			1%			
			2%			
			9%			
Capital phasing		*[%/a]*	16%			
			22%			25%
			24%			25%
			20%			25%
			5%	100%	100%	25%

All costs in Jan-2019 Rands

[1] From capital phasing, discount rate and economic lifetime.