Rev 1.2

Formal comments on the Draft Integrated Resource Plan (IRP) 2018

by Jarrad G. Wright[1] , Joanne Calitz[2] , Ntombifuthi Ntuli[3] , Ruan Fourie[4] , Mpeli Rampokanyo[5] , Pam Kamera[6] ,

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[1] jwright@csir.co.za

[2] jrcalitz@csir.co.za

[3] PNtuli@csir.co.za

[4] RFourie@csir.co.za

[5] MRampokanyo@csir.co.za

[6] PKamera@csir.co.za

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APPROVAL PAGE

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Prepared for	South African Department of Energy (DoE)		
By	Jarrad G. Wright	**Signature**	**Date**
	Joanne Calitz	**Signature**	**Date**
	Ntombifuthi Ntuli	**Signature**	**Date**
	Ruan Fourie	**Signature**	**Date**
	Mpeli Rampokanyo	**Signature**	**Date**
	Pam Kamera	**Signature**	**Date**
Approved for	CSIR, Energy Centre		
By	C. Carter-Brown	**Signature**	**Date**
Designation	Centre Head: Energy Centre		
Approved for	CSIR, Energy Centre		
By	Crescent Mushwana	**Signature**	**Date**
Designation	Research Group Leader: Energy Systems		
Approved for	CSIR, Energy Centre		
By	Robbie van Heerden	**Signature**	**Date**
Designation	Specialist: System Operations		

Distribution List

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EXECUTIVE SUMMARY

Background

As described in the Electricity Regulation Act No. 4 of 2006 and regulations in the Electricity Regulations for New Generation Capacity published in 2009; **the Department of Energy (DoE), the system operator (Eskom) and National Energy Regulator of South Africa (Nersa)** are responsible for the **development, publication and updating of the national level long-term electricity sector plan known as the Integrated Resource Plan (IRP)**, which includes adoption of the planning assumptions, determination of the electricity load forecast, modelling and scenario planning based on planning assumptions, determination of a base plan derived from a **least-cost** generation investment requirement, risk adjustment of the base plan and approval/gazetting of the plan. Although not explicit, due to the broad implications of the IRP, it is typically **consulted on via various engagement cycles** (including public consultations). As part of the IRP update process, the DoE engages in a multi-stage stakeholder engagement process (including public engagements) to ensure all affected stakeholders are consulted including national and local government, business, organised labour and civil society.

The most recent **approved and gazetted version of the IRP is the IRP 2010-2030**. An update to the IRP 2010-2030 was published in 2013 but this was never approved or gazetted. The input assumptions and base case of a further updated revision of the IRP **(the "Draft IRP 2016") was published by the DoE for comment in October 2016**. This revision included updated input assumptions including demand forecasts, existing plant performance, supply technology costs, decommissioning schedules and newly commissioned/under construction as well as preferred bidder power generation capacity. The time horizon for the Draft IRP 2016 was 2050. Some preliminary results were also shared in the form of a proposed Base Case and two other selected scenarios.

As part of the **Draft IRP 2016, the CSIR engaged in the public consultation** and submitted comments primarily related to establishing a **Least-cost Base Case, technology new-build limits (on solar PV and wind) and aligning costs to the latest Renewable Energy Independent Power Producer Programme (REIPPPP) Bid Window outcomes**.

As part of the Draft IRP 2018 update process, building on the Draft IRP 2016 and comments received, the DoE has requested for inputs from the public. Similar to the previous submission made by the CSIR, **this submission is a contribution to better understanding and improving on the current Draft IRP 2018**.

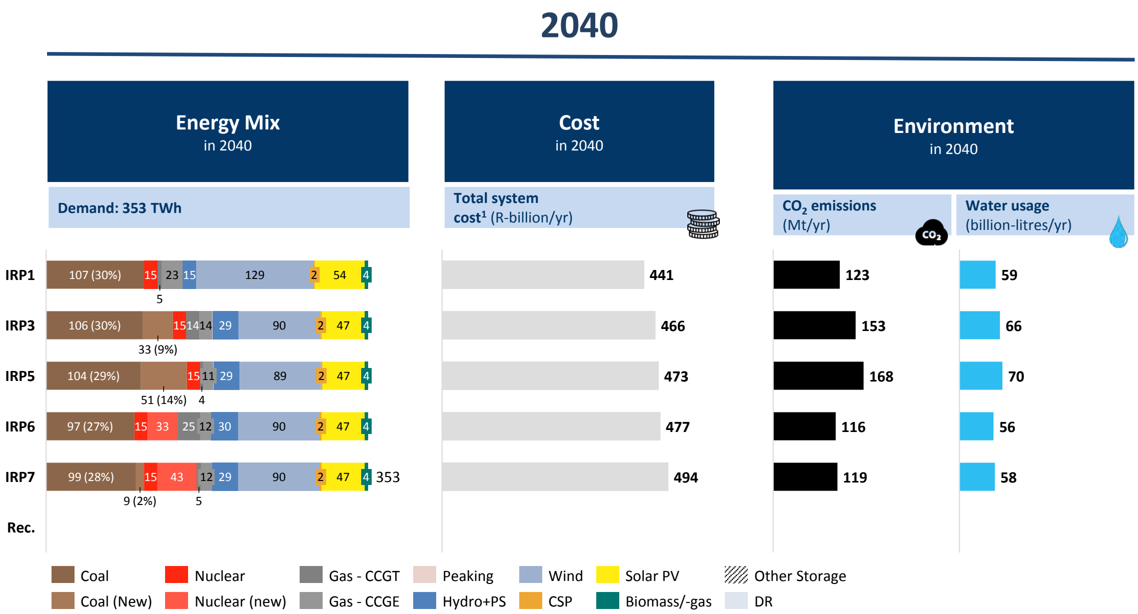
Key Messages

- Draft IRP 2018 is a **very different plan** to the Draft IRP 2016 and establishes solid principles based on the existing framework within which it is developed.
- It has now been **confirmed through the IRP1 scenario that Variable Renewable Energy (VRE) (solar PV and wind) combined with flexibility** in the form of natural gas fired generation capacity **are the least-cost combination of new-build options** as the existing coal fleet decommissions. This results in a power system that is 25% renewables-based (dominated by solar PV and wind) / 30% CO_2 free (incl. nuclear) by 2030 and 70% renewables-based by 2050.
- **By 2030 - the least-cost** IRP1 scenario is ≈**R10 bn/yr cheaper than the next best** IRP3 scenario. It is **also** ≈**R15-bn/yr cheaper than the Recommended Plan** by 2030.
- **By 2040 - the least-cost** IRP1 scenario continues to deploy solar PV, wind and flexible capacity and is ≈**R15-55 bn/yr cheaper than all other scenarios**. It also exhibits **similar** CO_2 **emissions and water usage** to that of the IRP6 and IRP7 where the combination of a strict CO_2 emissions trajectory and annual new-build limits on VRE results in significantly increased total costs.
- **By 2050 - the least-cost** IRP1 scenario is ≈**R30-60 bn/yr cheaper than all other scenarios**. This scenario **also exhibits the least** CO_2 **emissions and least water usage by 2050**.
- Thus, it is important to reiterate again that **South Africa has the unique opportunity to decarbonise its electricity sector without pain**. A **clean and cheap power system are no longer trade-off anymore** in South Africa.
- The deployment of **solar PV, wind and flexibility** is also consistent across all scenarios and thus deploying these new-build options is adaptable and **resilient to changes in a range of input assumptions**.
- **Notable energy planning risks and opportunities** have been identified including the Energy Availability Factor (EAF) of the existing Eskom coal fleet (and decommissioning schedule), completion of under construction coal capacity (Medupi/Kusile), expected cost trajectories of stationary storage and Demand Side Response (DSR).
- When incorporating these energy planning risks and opportunities into **a risk-adjusted scenario**, **increased levels of new-build solar PV and wind** are deployed along with some **stationary storage**. There is also a shift in timing of new-build capacity to 2023. The deployment of stationary storage also results in a notable **decreased deployment of flexible natural gas-fired capacity** and reduced natural gas fuel offtake.
- Demand growth expectations impact only the timing of new-build capacity whilst the energy mix remains largely unchanged as a combination of solar PV, wind and flexible gas-fired capacity.

- **New-build coal** capacity is only built **post-2030** if CO_2 **emissions are not too restrictive (PPD Moderate) and new-build VRE is limited annually**.
- **New-build nuclear** capacity is only built **post-2030** if CO_2 **emissions are very restrictive (Carbon Budget) and new-build VRE is limited annually**.
- If the **DoE Recommended Plan** of the Draft IRP 2018 is implemented - there is an expectation of **net employment increases** (as the power system grows) driven by employment in natural gas (≈55 000 jobs by 2030), solar PV (≈50 000 jobs by 2030), wind (≈60 000 jobs by 2030), nuclear (≈44 000 jobs) **but a net reduction in the coal sector** of ≈100 000 jobs by 2030.
- **The national energy security risk (cost and volumes) of imported natural gas is relatively small** as it only contributes 2-5% of the energy mix by 2030 and up to 15% by 2050. The natural gas-fired flexible capacity could also be replaced by appropriate domestic flexibility sources or stationary storage (if costs decline sufficiently).
- **Post 2030** - the **key drivers for new-build** technology choices are **VRE new build limits, decommissioning** of the existing coal fleet, **stationary storage** and to a lesser extent **demand growth**.
- A brief analysis has been included on **network infrastructure**. The inclusion of **shallow grid integration costs is a welcome development** as part of the Draft IRP 2018. The least-cost (as demonstrated by IRP1) remain largely unchanged even with these inclusions. Periodic processes including the Transmission Development Plan (TDP) and Strategic Grid Plan (SGP) inform these deep transmission network costs and it has been demonstrated that **deep transmission network costs do not influence the generation mix**. Localised network integration issues and focus areas will emerge but these will be managed by the periodic updating of the TDP and SGP (or equivalent).
- A brief analysis has been included on **system services** in future (transient stability (and associated "system strength"), reactive power and voltage control, frequency stability (with a particular focus on system inertia) and variable resource forecasting). **No system integration issues are foreseen pre-2030** but an informed and co-ordinated work program is necessary to prepare for post-2030 increased VRE penetration levels. The **cost of ensuring system sufficient system inertia** has been quantified considering the worst-case of using state-of-the-art technology (very high costs, no further technology and/or cost advancements) nor further improved engineering solutions to deal with low-inertia systems. In all scenarios, the **worst-case costs are ≈1% of total system costs by 2050**.

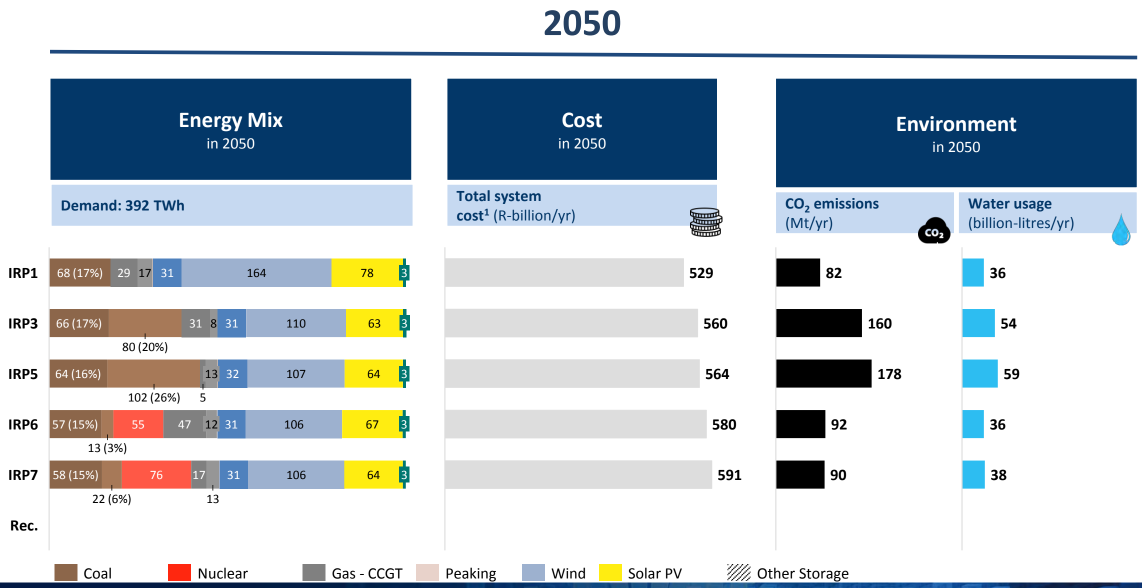
Energy mix by 2030 similar across scenarios as coal still dominates while IRP1 is ≈R10bn/yr cheaper than IRP7, IRP7 lowest CO_2 emissions

Least-cost mix confirmed as new-build solar PV, wind and flexible capacity (NG) - ≈R15-55 bn/yr cheaper than alternative scenarios



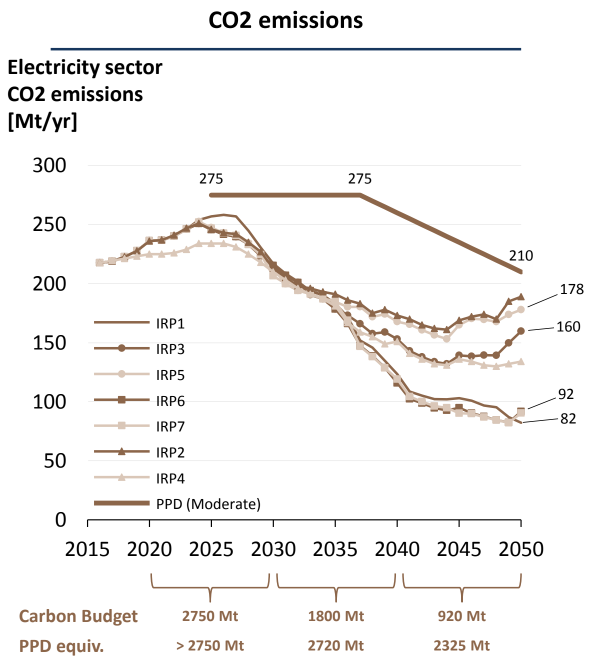
56 Sources: DoE Draft IRP 2018; Eskom on Tx, Dx costs; CSIR analysis; flaticon.com

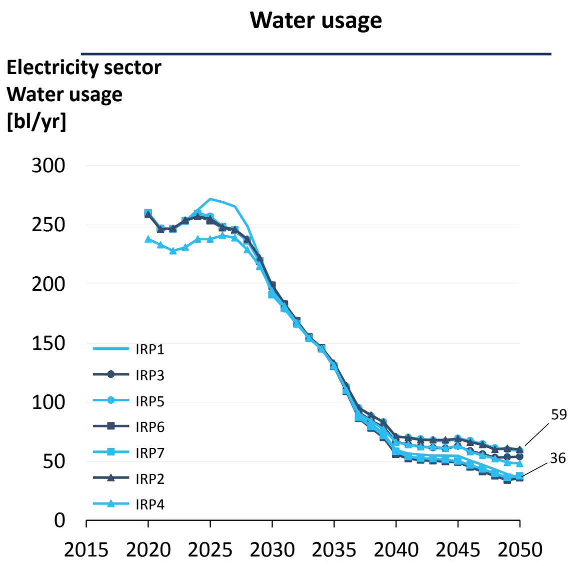
By 2050 - Least-cost mix is 70% solar PV and wind, ≈R30-60 bn/yr cheaper than alternatives, least CO_2 emissions and least water usage



CO2 emissions trajectories for PPD Moderate never binding (only CB) while water use declines as expected as coal fleet decommissions

Scenarios from Draft IRP 2018





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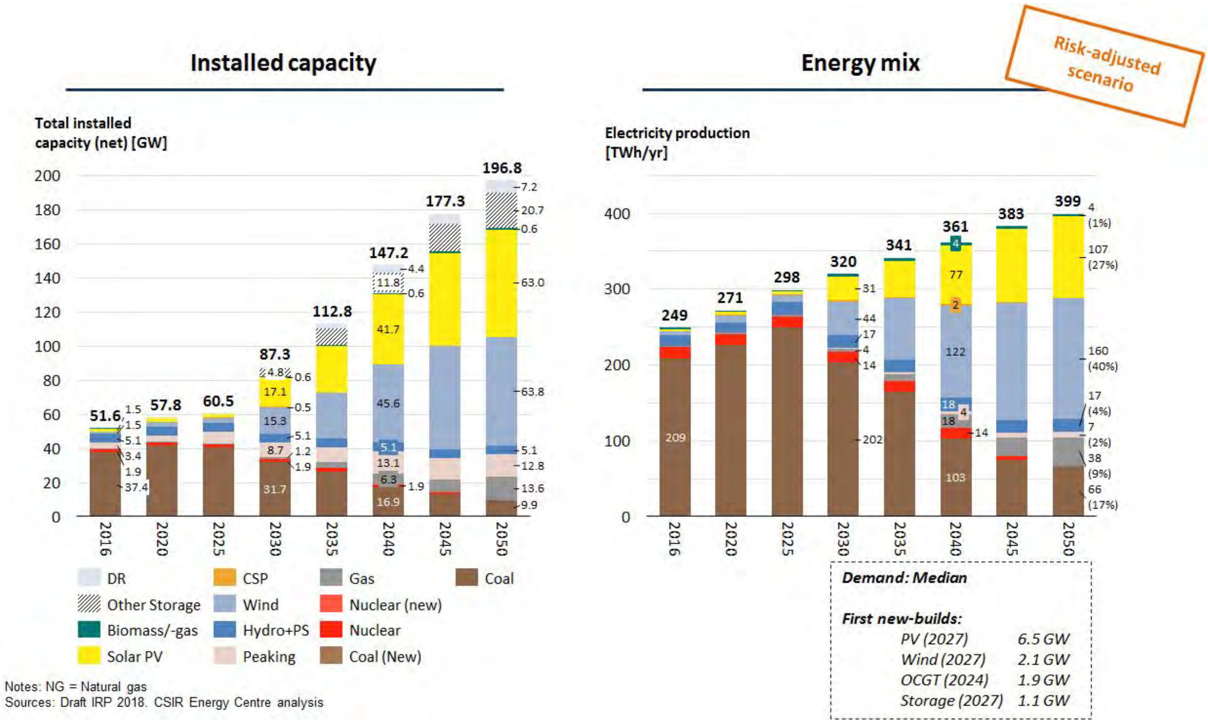
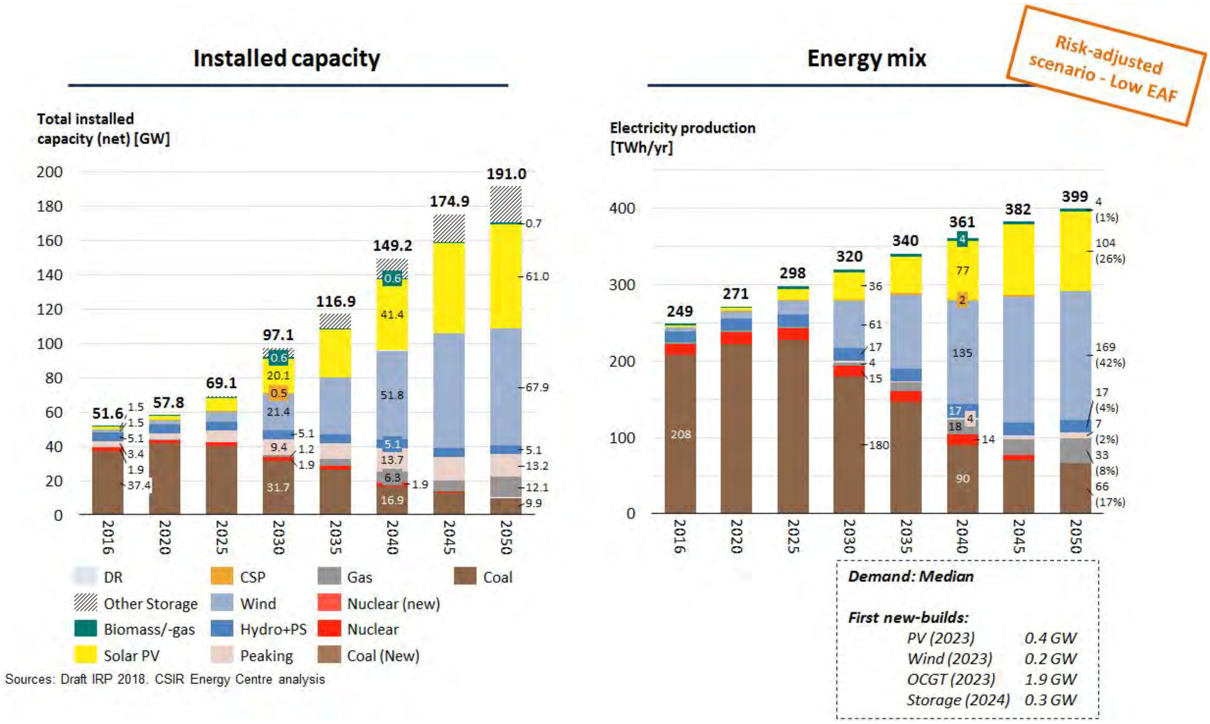
Risk-adjusted scenarios

(accounting for key energy planning risks and opportunities - stationary storage, DSR, further VRE learning)



(accounting for key energy planning risks and opportunities - low coal fleet EAF, stationary storage, DSR, further VRE learning)



Recommendations: Future IRPs

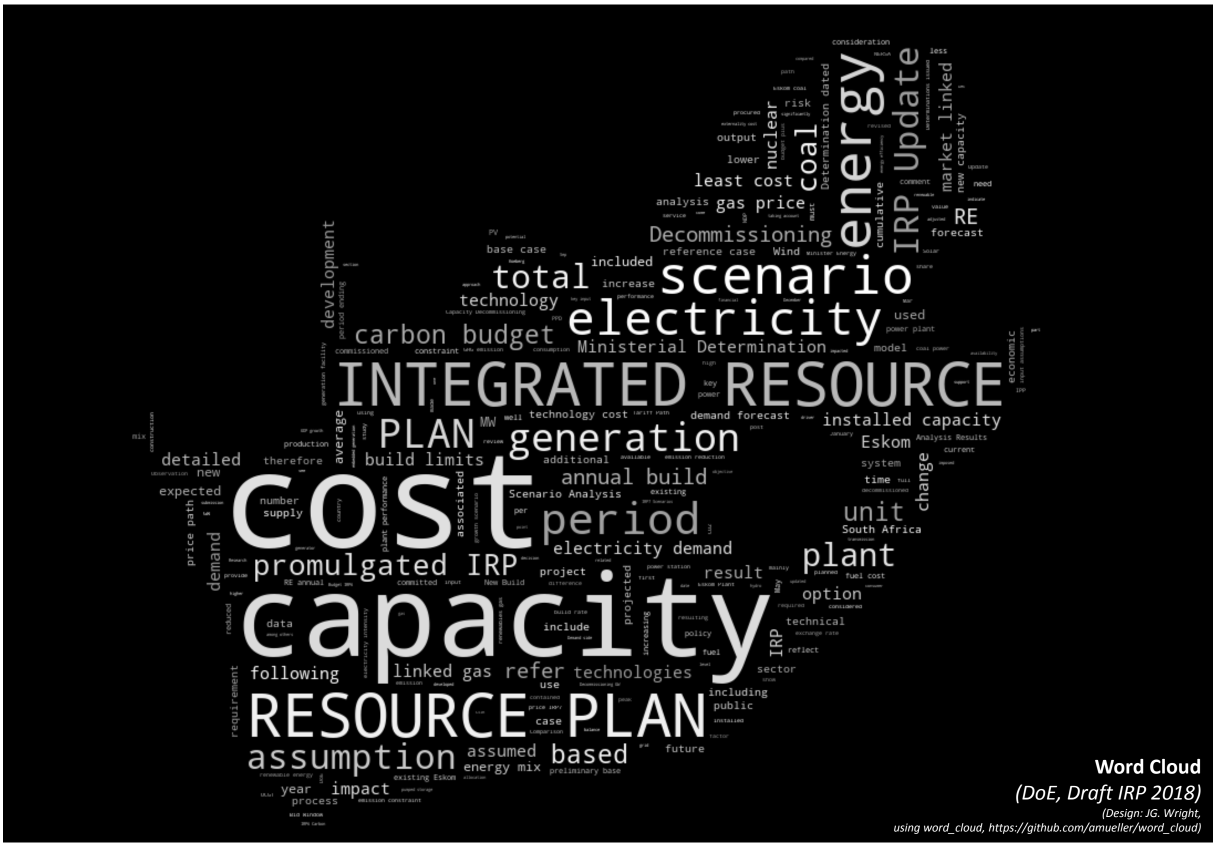
- There is a distinct need to have transparency in all input assumptions, models and outcomes comprehensively and consistently published.
- Investigate and establish the need for annual technology new-build limits. In the interim, remove annual new-build limits on any new-build technologies until further investigations establish the need for them (solar PV and wind are currently being constrained).
- Inclusion of economic impacts of scenarios in future IRP iterations should be explicit. At the very least, employment impacts should be analysed and published.
- Optimise the existing coal fleet while remaining cognisant of opportunity cost of capital expenditure on older assets (retrofitting for improved reliability, efficiency and flexibility).
- Improved approaches are critical to better understanding the demand-side (sector shifts, load profile shape, price elasticity of demand).
- Better understanding all technology cost trajectories for domestic application (periodic).
- Develop and implement an integrated program of work on long-term power system integration and system services topics i.e. stability, system strength, reactive power/voltage control and variable resource forecasting.
- Focussed attention should be placed on further investigating and leveraging domestic flexibility sources and/or storage including e.g. Domestic fuels (UCG, CBM, shale gas, offshore gas, hydrogen), DSR, biomass/-gas, CSP, storage (pumped, batteries).

Recommendations: Long-term structural and strategic

- Formally establishing links/triggers between IRP and Medium-term System Adequacy Outlook (MTSAO) processes (or equivalent). Periodic IRP updating should be prioritised to address the dynamic planning environment within which the energy sector is operating.
- Further understanding the just transition to address labour and socio-economic impacts in the energy sector. A particular focus on the coal sector is needed as a significantly affected incumbent sector.
- Integrate national and local level energy planning for improved co-ordination and leveraging of opportunities.
- Full sector-coupling opportunities (not just electricity) with IEP further informing this.
- Continue further to investigate approaches that include geospatial components of the IRP – supply/network/demand (co-optimisation)
- Further investigations into impacts/opportunities of new/emerging technologies e.g. stationary storage, e-vehicles, DSR.

Word Clouds - IRP trends

Word Cloud - Draft IRP 2018



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ABBREVIATIONS

AMPS	All Media and Products Survey
BW	Bid Window
CAES	Compressed Air Energy Storage
CBM	Coal Bed Methane
CC-GE	Combined Cycle Gas Engine
CCT	Critical Clearence Time
CCGE	Combined Cycle Gas Engine
CCGT	Combined Cycle Gas Turbine
CLN	Customer Load Network
COMELEC	Comité Maghrébin de l'Electricité
COUE	Cost of Unserved Energy
CPI	Consumer Price Inflation
CSIR	Council for Scientific and Industrial Research
CSP	Concentrated Solar Power
DoE	Department of Energy
DSR	Demand Side Response
EAF	Energy Availability Factor
EAPP	Eastern African Power Pool
EIUG	Energy Intensive User Group of Southern Africa
EE	Energy Efficiency
EG	Embedded Generation
EMS	Energy Management System
ENTSO-E	European Network of Transmission System Operators for Electricity
ERCOT	Electricity Reliability Council of Texas
EV	Electric Vehicle
EWH	Electric Water Heating
FCEH	Final Consumption Expenditure of Households

FOM	Fixed Operations and Maintenance
FTE	Full-time Equivalent
GCCA	Grid Connection Capacity Assessment
GHG	Greenhouse Gas
GDP	Gross Domestic Product
HVDC	High Voltage Direct Current
ICE	Internal Combustion Engine
IEA	International Energy Agency
INDC	Intended Nationally Determined Contribution
IPP	Independent Power Producer
IRP	Integrated Resource Plan
I-JEDI	International Jobs and Economic Development Impacts
JEDI	Jobs and Economic Development Impacts
LCOE	Levelised Cost of Electricity
LDC	Load Duration Curve
LNG	Liquified Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MAE	Mean Absolute Error
MTS	Main Transmission Substation
MTSAO	Medium-term System Adequacy Outlook
NDC	Nationally Determined Contribution
Nersa	National Energy Regulator of South Africa
NREL	National Renewable Energy Laboratory
openmod	Open Energy Modelling Initiative
OCGT	Open Cycle Gas Turbine
OPSD	Open Power System Data
OnSSET	OpeN Source Spatial Electrification Toolkit

OSeMOSYS	Open Source Energy Modelling System
PLDV	Private Light-Duty Vehicle
PM	Particulate matter
PPD	Peak Plateau Decline
PSAT	Powerflow and Short-Circuit Analysis Tool
PyPSA	Python for Power Systems
RE	Renewable Energy
REIPPPP	Renewable Energy Independent Power Producer Programme
RoCoF	Rate of Change of Frequency
SAARF	South African Audience Research Foundation
SALGA	South African Local Government Association
SAPP	Southern African Power Pool
SciGRID	Scientific GRID
SCO	Synchronous Condensor
SGP	Strategic Grid Plan
SNSP	System Non-Synchronous Penetration
SO	System Operator
SSAT	Small-Signal ATool
STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
TDP	Transmission Development Plan
TSAT	Transient Security Assessment Tool
TSO	Transmission System Operator
UCG	Underground Coal Gasification
UFLS	Under Frequency Load Shedding
UNFCCC	United Nations Framework Convention on Climate Change
VoLL	Value of Lost Load
VSAT	Voltage Security Assessment Tool

WSAT Wind Security Assessment Tool

VOM Variable Operations and Maintenance

VRE Variable Renewable Energy

WAPP Western African Power Pool

WECC Western Electricity Coordinating Council

1 Background

1.1 The IRP process and new supply capacity in South Africa

1.1.1 General IRP process overview

As described in the Electricity Regulation Act No. 4 of 2006 [1] and regulations in the Electricity Regulations for New Generation Capacity published in 2009 [2]; the DoE, the system operator (Eskom) and Nersa are responsible for the development, publication and updating of the national level long-term electricity sector plan known as the IRP, which includes:

a) Adoption of the planning assumptions;

b) Determination of the electricity load forecast;

c) Modelling and scenario planning based on planning assumptions;

d) Determination of a base plan derived from a least-cost generation investment requirement;

e) Risk adjustment of the base plan, which shall be based on:

   i) The most probable scenarios;

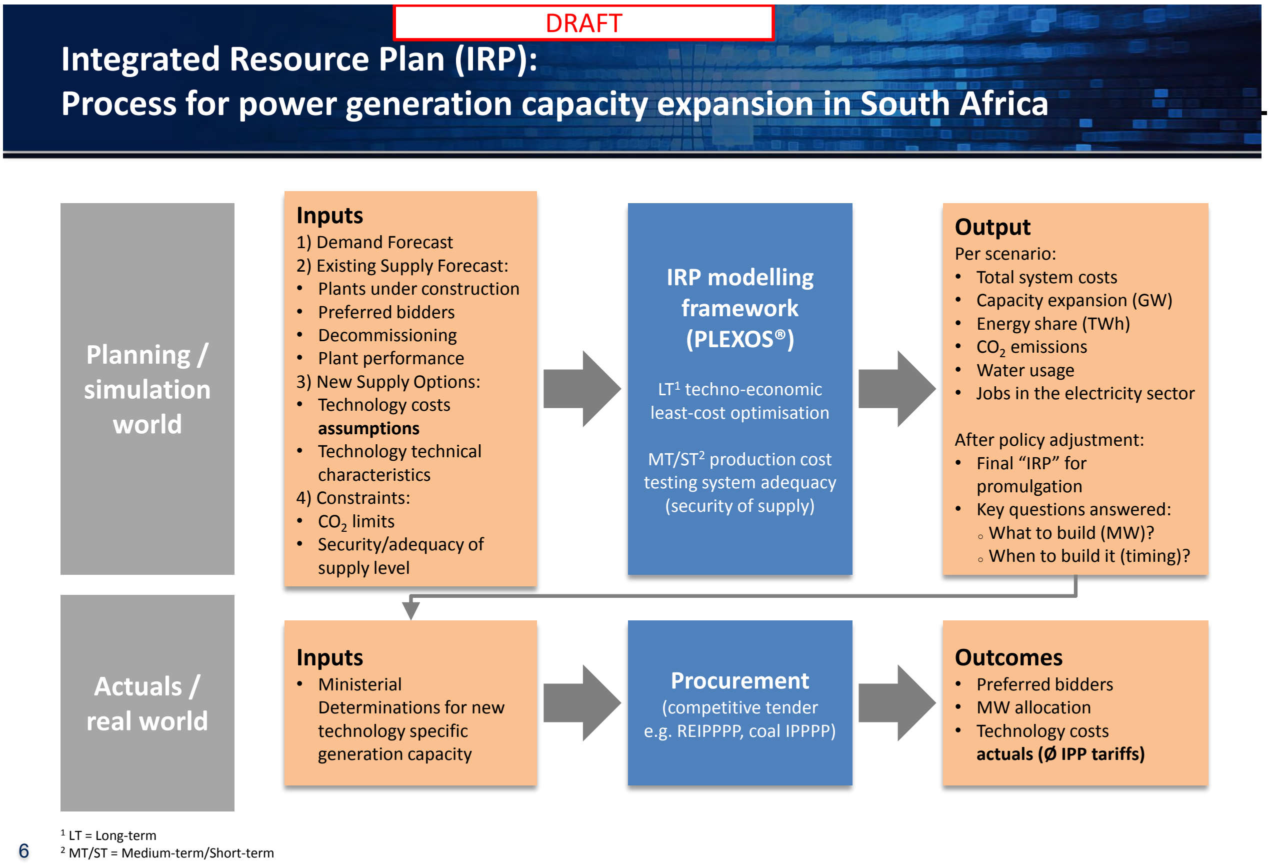
   ii) Government policy objectives for a diverse generation mix, including renewable and alternative energies, demand side management and energy efficiency; and

f) Approval and gazetting of the integrated resource plan.

Although not explicit above, due to the broad implications of the IRP for various stakeholders, it is typically consulted on via various engagement cycles (including public consultations). As part of the IRP update process, the DoE engages in a multi-stage stakeholder engagement process (including public engagements) to ensure all affected stakeholders are consulted including national and local government, business, organised labour and civil society.

The IRP is a living plan that is planned to be updated periodically in order to ensure future generation capacity investments are made on an informed basis considering the latest trends and developments both locally and internationally in supply technology costs, demand forecasts for electricity and existing generation fleet performance and lifetime. The primary result from the IRP is the identification of the generation capacity required (per technology) and the requisite timing in the long-term based on a set of input assumptions and pre-defined constraints. The primary responsibility for energy policy objectives and priorities are provided by the DoE but guided by policy priorities from other national departments.

Following this process, the plan is approved by the Minister of Energy and gazetted in the Government Gazette. The Minister then makes Determinations informed by the gazetted IRP on generation capacity to be procured. This process is shown graphically in Figure 1 with the scenario based approach taken in this process shown graphically in Figure 2.



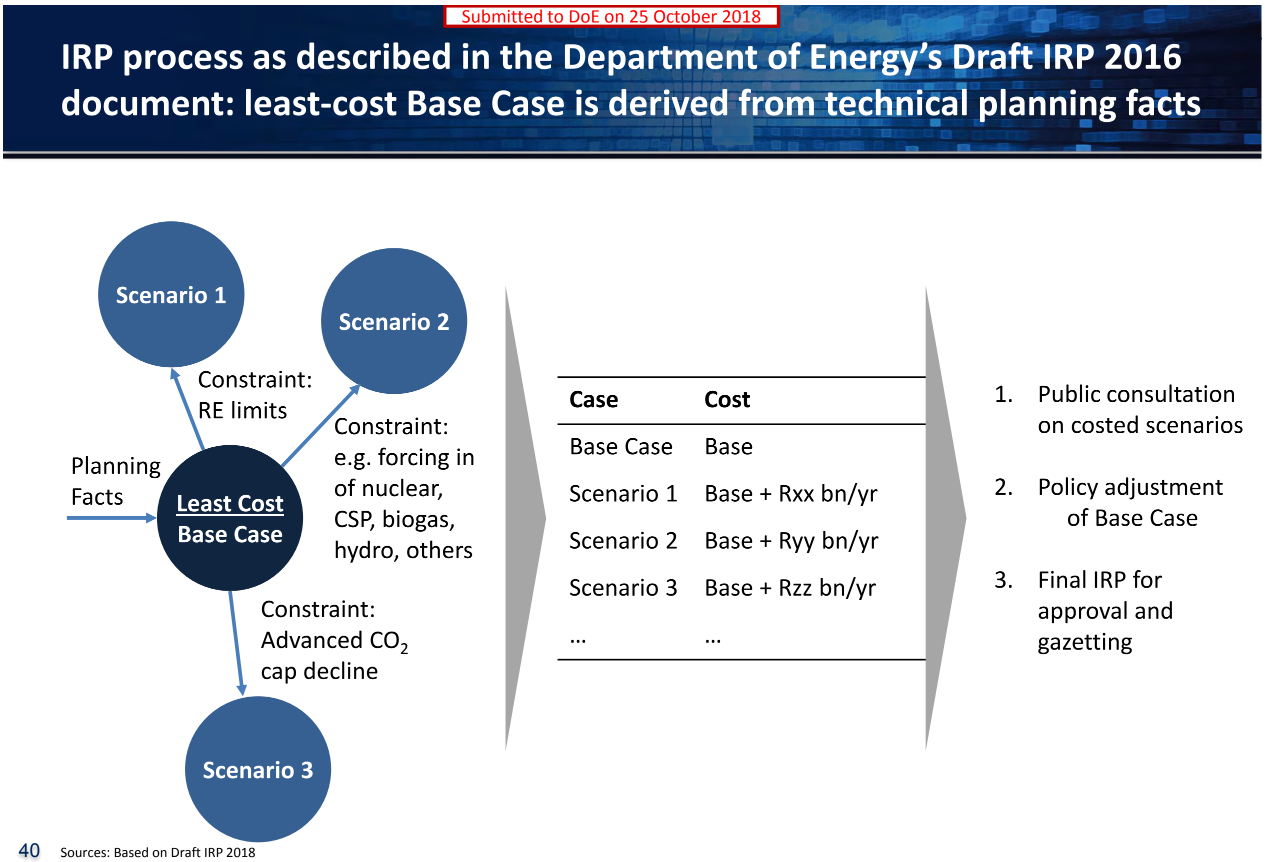


Figure 2: Scenario based planning as adopted in the IRP planning process to establish the least-cost Base Case

1.1.2 IRP 2010-2030

The most recent version of the IRP that has been approved and gazetted is the IRP 2010-2030 [3]. The Policy Adjusted Scenario from the IRP 2010-2030 is currently being implemented and is summarised in Figure 3. An update to the IRP 2010-2030 was published in 2013 but this was never approved or

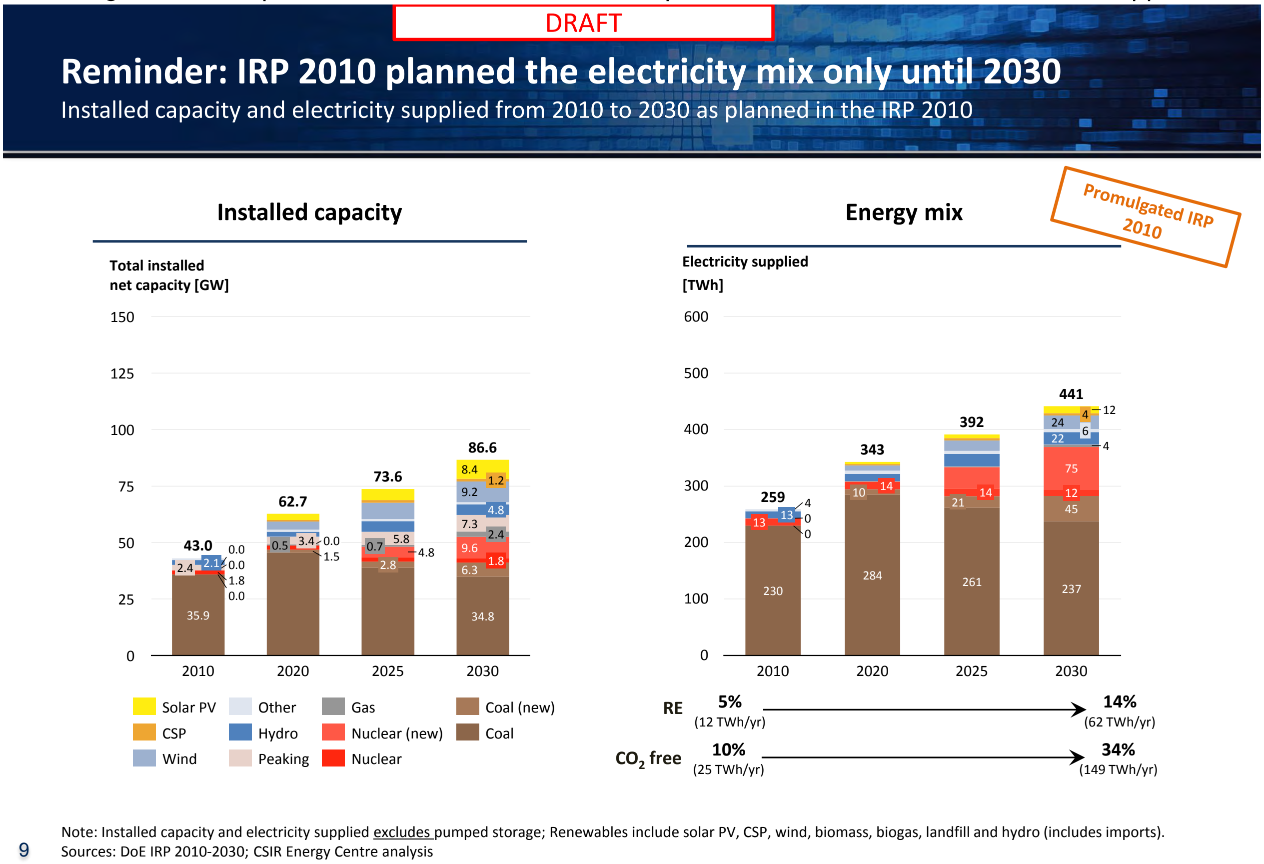


Figure 3: Installed capacity (GW) and energy mix (TWh) to 2030 from the IRP 2010 (Policy adjusted)

1.1.3 Draft IRP 2016

The input assumptions and base case of a further updated revision of the IRP (the "Draft IRP 2016") was published by the DoE for public comment in October 2016. This revision included updated input assumptions including demand forecasts, existing plant performance, supply technology costs, decommissioning schedules and newly commissioned/under construction as well as preferred bidder power generation capacity (as part of the REIPPPP and base-load coal Independent Power Producers (IPPs)). The time horizon for the Draft IRP 2016 is 2060 (but only up to 2050 is reported on). Some preliminary results are also shared in the form of a proposed Base Case (as shown in Figure 4) and two other selected scenarios [5, 6].

As part of this Draft IRP 2016, the DoE engaged publicly with a range of written comments received (from November 2016 to March 2017). The Council for Scientific and Industrial Research (CSIR) engaged in this public consultation and submitted comments [7, 8].

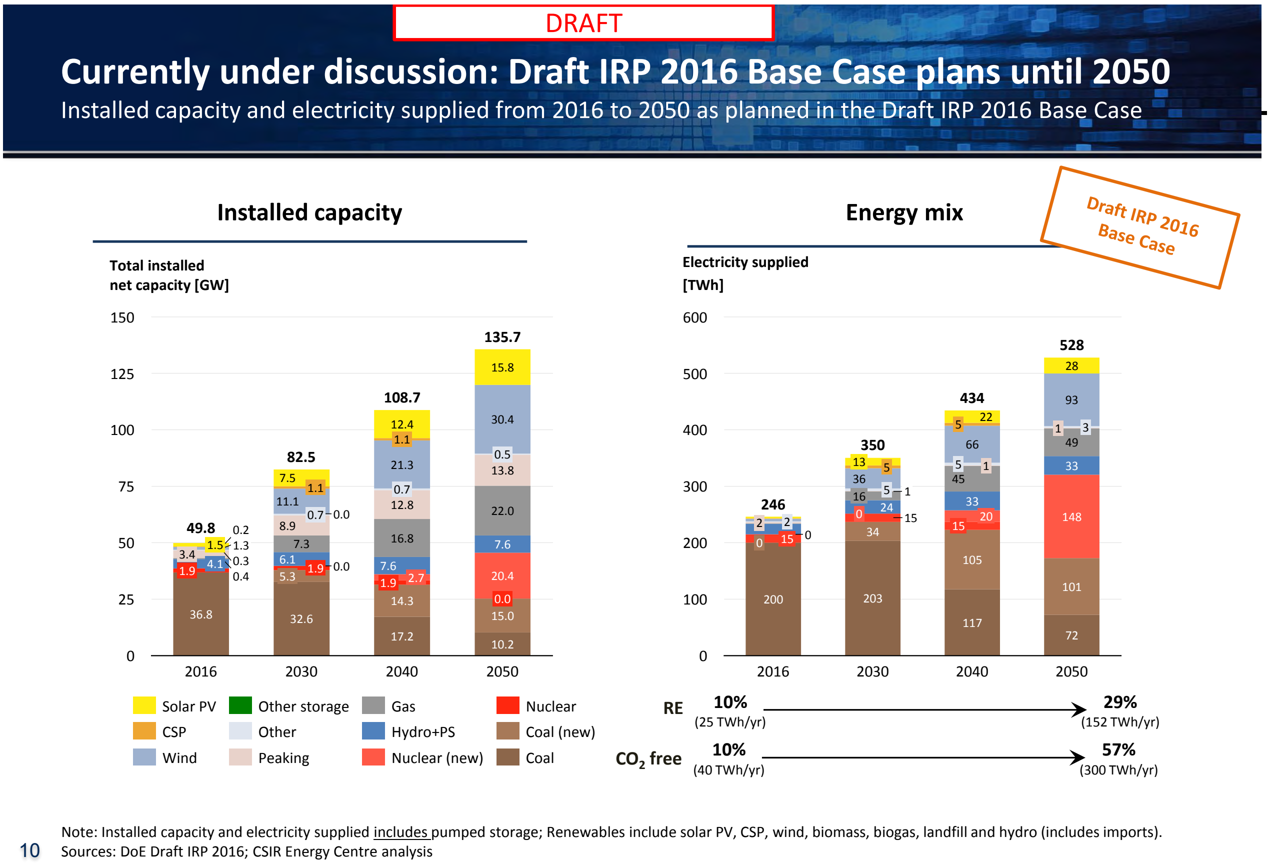


Figure 4: Installed capacity (GW) and energy mix (TWh) to 2050 from the Draft IRP 2016

1.2 CSIR mandate and this submission

The global energy industry is transitioning, driven by the need for more efficient end-use of energy enabled by the proliferation of recently realised low-cost Renewable Energy (RE) and new technologies (electric vehicles, hydrogen, batteries). The CSIR's energy research responds to these global mega-trends whilst addressing national research priorities. The objective of the CSIR is to become a leading research institution on the African continent in energy and to be globally recognised.

The formal comments provided as part of this submission is undertaken as part of the energy research agenda fulfilled under two of the research groups at the CSIR Energy Centre - *"Energy Systems"* and *"Energy Industry"*.

The CSIR was established in 1945 and is mandated by the Scientific Research Council Act of 1988 (updated in 1990) [9] section (3) as follows:

> *The objects of the CSIR are, through directed and particularly multi-disciplinary research and technological innovation, to foster, in the national interest and in fields which in its opinion should receive preference, industrial and scientific development, either by itself or In co-operation with principals from the private or public sectors, and thereby to contribute to the improvement of the quality of life of the people of the Republic, and to perform any other functions that may be assigned to the CSIR by or under this Act.*
> *- THE SCIENTIFIC RESEARCH COUNCIL ACT No 46 of 1988*

As part of the Draft IRP 2018 update process, building on the Draft IRP 2016 and comments received, the DoE has requested for inputs from the public. Similar to the previous submission made as part of the Draft IRP 2016 by the CSIR [8, 7], this submission is a contribution to better understanding and improving on the current Draft IRP 2018 as it relates to public discussion, peer-review and scrutiny of energy data, models and scenarios.

As mentioned in the previous submission by the CSIR, this is has proliferated into the energy planning and operations environment with key concepts presented briefly by Pfenninger in [10] with some examples of open modelling initiatives recently cited like Open Power System Data (OPSD) [11], Open Energy Modelling Initiative (openmod) [12] and open energy data via European Network of Transmission System Operators for Electricity (ENTSO-E) [13]. Examples of modelling tools like Open Source Energy Modelling System (OSeMOSYS) [14], Balmorel [15], Calliope [16], Python for Power Systems (PyPSA) [17], the OpeN Source Spatial Electrification Toolkit (OnSSET) [18], Scientific GRID (SciGRID) [19] and Dispa-SET [20] further reveal the trend towards open, transparent and collaborative energy data and models. Of particular interest considering the modelling framework used for the IRP 2016[1] is the open publishing of PLEXOS® models in continental Europe [22], Ireland [23], Australia [24] and the USA [25]. PLEXOS® datasets for various regions including inter alia Southern African Power Pool (SAPP), Eastern African Power Pool (EAPP), Western African Power Pool (WAPP), Electricity Reliability Council of Texas (ERCOT), Western Electricity Coordinating Council (WECC), the Caribbean, Phillpines and Chile are also provided by Energy Exemplar but are commercial at this stage [21].

1.3 Structure of comments

This submission by the CSIR is part of the formal written inputs as requested by the DoE. These are informed by independent modelling and analysis performed by CSIR in order to provide additional scientific knowledge and evidence-base for the IRP public consultation process. The submission includes:

- **Report (this document):** Formal comments on the Draft Integrated Resource Plan (IRP) 2018 *(providing details of the analyses undertaken and comments provided by CSIR)*;
- **Presentation:** Formal comments on the Draft Integrated Resource Plan (IRP) 2018 *(an easy to digest presentation of the analysis undertaken in the form of a slide deck)*

More specifically, this Report is structured as follows:

- Chapter 1 is this chapter and provides context as well as background to this document as part of the Draft IRP 2018 public consultation process.
- Chapter 2 summarises the outcomes of the Draft IRP 2018 scenarios for ease of reference.
- Chapter 3 presents an analysis on the economic impacts of the technology choices made as part of the DoE Recommended Plan in the Draft IRP 2018.
- Chapter 4 provides a range of scenarios modelled by CSIR to demonstrate notable energy planning risks as well as descriptive comments on key topics.

[1] PLEXOS® Integrated Energy Model by Energy Exemplar [21]

- Chapter 5 provides commentary on the inclusion of networks into the IRP in future whilst also highlighting key the need for new approaches to system services and integration as VRE penetration levels increase.

During this public consultation period, the CSIR have formally engaged with key identified stakeholders to share some of the analyses and outcomes presented in this submission. These stakeholders included:

- Department of Energy (DoE)
- Eskom
- National Energy Regulator of South Africa (Nersa)
- Energy Intensive User Group of Southern Africa (EIUG)
- South African Local Government Association (SALGA)

1.4 Acknowledgements

The authors would like to thank CSIR Executive for continued support in preparing this submission.

This work is wholly funded internally by CSIR.

2 Draft IRP 2018 Scenarios

Summaries of the scenarios documented in the Draft IRP 2018 by the DoE are provided in the subsections that follow [26]. The key parameters considered by the DoE and how they change across these scenarios is provided in Table 1. For consistency, results from all scenarios are compared in the following dimensions:

- Net installed generation capacity (per technology) - [MW];
- Production of energy (per technology) - [TWh];
- Total system cost - [ZAR-billion];
- CO_2 emissions - [Mt/yr]; and
- Water usage - [bl/yr]

Table 1: Key scenario parameters analysed as part of the Draft IRP 2018

Parameter	IRP1	IRP2	IRP3	IRP4	IRP5	IRP6	IRP7
Demand forecast	Median	Upper	Median	Lower	Median	Median	Median
CO_2 *mitigation*	PPD	PPD	PPD	PPD	PPD	CB	CB
Annual new-build limit (RE)	-	Yes	Yes	Yes	Yes	Yes	Yes
Fuel prices	Const.	Const.	Const.	Const.	Market	Const.	Market.
Tx collector station costs	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Const. - Constant, Market - Natural gas linked to IEA expected market price
PPD - Peak Plateau Decline, CB - Carbon Budget

2.1 IRP1 (Least-cost)

The installed capacity and expected energy mix for the IRP1 scenario from the Draft IRP 2018 is summarised in Figure 5. The first new-build capacity is 2.3 GW of gas represented by Combined Cycle Gas Engines (CC-GEs) and 0.1 GW of peaking capacity in the form of Open Cycle Gas Turbines (OCGTs) in 2025. The first new-build solar PV is 2.3 GW in 2027 whilst that for wind is 2.5 GW in 2028. There is also 250 MW of landfill gas built in 2026.

By 2030, coal still dominates the energy mix supplying a similar amount of energy as it did in 2016 and comprising 64% of the energy mix ($\approx$200 TWh). Nuclear and hydro (mostly imported) also continue to play a similar notable role by 2030. The unconstrained deployment of wind and solar PV results in their energy share moving from <3% in 2016 to 20% of the energy mix by 2030. Although a seemingly considerable amount of gas-fired capacity exists by 2030 (14.4 GW comprised of 9.9 GW of CC-GEs, 4.1 GW of OCGTs), the use of this capacity results in only 3.0% of the energy mix.

Beyond 2030, as the existing coal fleet decommissions combined with the need to meet additional demand, new-build capacity in the form of flexible gas-fired capacity, solar PV and wind is deployed. Imported hydro (2.5 GW from Inga in DRC) is also deployed in 2041. By 2040, 26 GW of gas-fired gas capacity (Combined Cycle Gas Turbines (CCGTs) and CC-GE), 8 GW of OCGTs, 21 GW of solar PV and 38 GW of wind capacity exists. Only 17 GW of coal capacity still exists by 2040 and 10 GW by 2050. By 2050, 36 GW of gas-fired gas capacity, 13 GW of OCGTs, 31 GW of solar PV and 50 GW of wind capacity exists. The energy mix in 2040 is only 30% coal, 4% nuclear, 8% natural gas, 36% wind

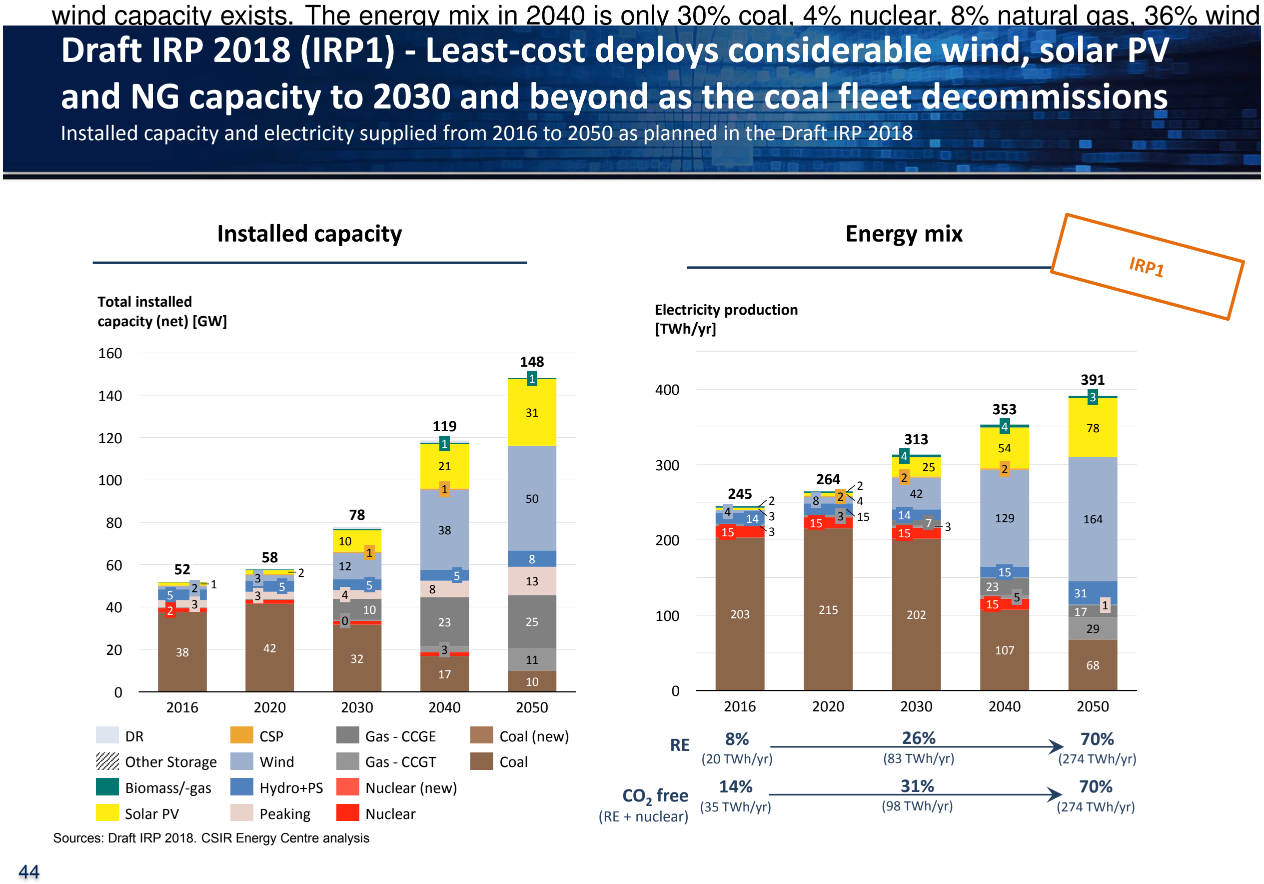


Figure 5: Installed capacity and energy mix for 2016-2050 from IRP1 in Draft IRP 2018

2.2 IRP3 (New-build limits)

The installed capacity and expected energy mix for the IRP3 scenario from the Draft IRP 2018 is summarised in Figure 6. Constrained solar PV capacity (1.0 GW) and wind capacity (1.6 GW) is first deployed in 2024 and 2025 respectively and continues similarly to 2030. This results in a total of 9.3 GW and 13.0 GW of installed solar PV and wind by 2030. Peaking OCGT capacity is first deployed in 2025 (0.1 GW) and CC-GEs (2.5 GW) in 2026. There is 250 MW of landfill gas built in 2029.

By 2030, coal again dominates the energy mix supplying a similar amount of energy as it did in 2016 and comprising 63% of the energy mix ($\approx$200 TWh). Nuclear and hydro (mostly imported) also continue to play a similar notable role by 2030. The constrained deployment of wind and solar PV results in their energy share moving from <3% in 2016 to 21% of the energy mix by 2030. Again, a seemingly considerable amount of gas-fired capacity exists by 2030 (14.3 GW comprised of 10.3 GW of CC-GEs and CCGT, 4.0 GW of OCGTs), the use of this capacity results in just less than 6% of the energy mix.

Beyond 2030, new-build capacity in the form of flexible gas-fired capacity, solar PV and wind continues to be deployed. Imported hydro (2.5 GW from Inga in DRC) is also deployed from 2033. There is new-build coal capacity deployed from 2036 (1.5 GW) resulting in total coal capacity of 22 GW by 2040 and 2050. There is 20 GW of gas-fired gas capacity (CCGTs and CC-GE), 7 GW of OCGTs, 18 GW of solar PV and 26 GW of wind capacity by 2040. By 2050, 29 GW of gas-fired gas capacity, 11 GW of OCGTs, 25 GW of solar PV and 30 GW of wind capacity exists. The energy mix in 2040 is 39% coal,

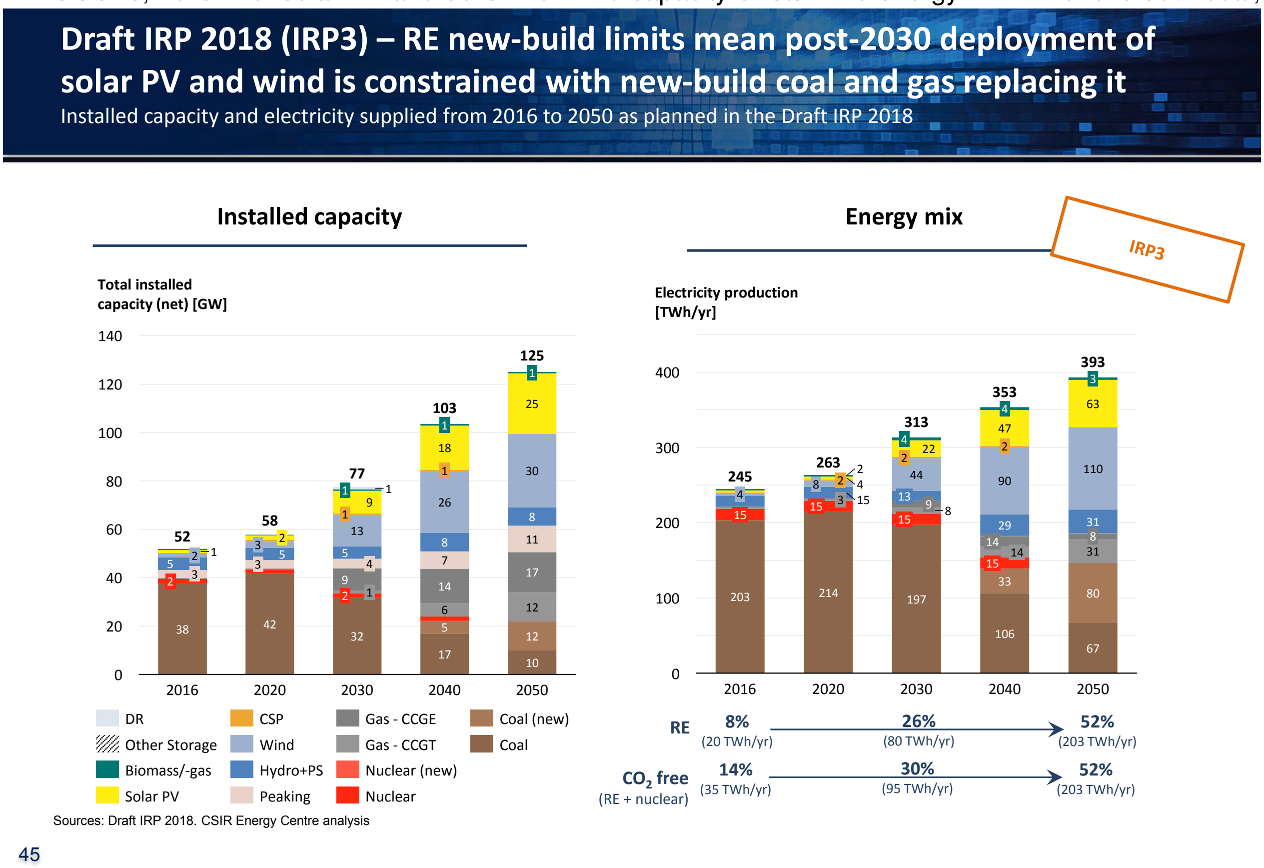


Figure 6: Installed capacity and energy mix for 2016-2050 from IRP3 in Draft IRP 2018

2.3 IRP5 (Market-linked natural gas)

The installed capacity and expected energy mix for the IRP5 scenario from the Draft IRP 2018 is summarised in Figure 7. Similar to IRP3, solar PV capacity and wind capacity is first deployed in 2024 and 2025 respectively and continues similarly to 2030. This results in a total of 8.8 GW and 13.0 GW of installed solar PV and wind by 2030. Peaking OCGT capacity is first deployed in 2025 (0.3 GW) and CC-GEs (2.3 GW) in 2026. There is 250 MW of landfill gas built in 2029.

By 2030, coal still dominates the energy mix supplying a similar amount of energy as it did in 2016 and comprising 63% of the energy mix (≈200 TWh). Nuclear and hydro (mostly imported) also continue to play a similar notable role by 2030. The constrained deployment of wind and solar PV results in their energy share moving from <3% in 2016 to 21% of the energy mix by 2030. With a market linked natural gas price, notably less natural gas capacity is deployed and utilised in this scenario - by 2030 (9.3 GW comprised of 9.3 GW of CC-GEs and CCGT, 4.0 GW of OCGTs). This use of this capacity results in just less than 5% of the energy mix by 2030.

Beyond 2030, considerable new-build coal capacity is deployed due to the increased market linked natural gas price resulting in 25 GW of coal capacity by 2040 and 2050. Although still considerable, flexible gas-fired capacity deployment is notably reduced in this scenario by 2040 (18 GWCCGTs and CC-GE, 6.4 GW of OCGTs) and 2050 (23 GWCCGTs and CC-GE, 13 GW of OCGTs). Similar solar PV and wind are still deployed to 2040 and 2050 as in IRP3. Imported hydro (2.5 GW from Inga in DRC) is also deployed from 2031. The energy mix in 2040 is 44% coal, 4% nuclear, 4% natural gas, 25% wind

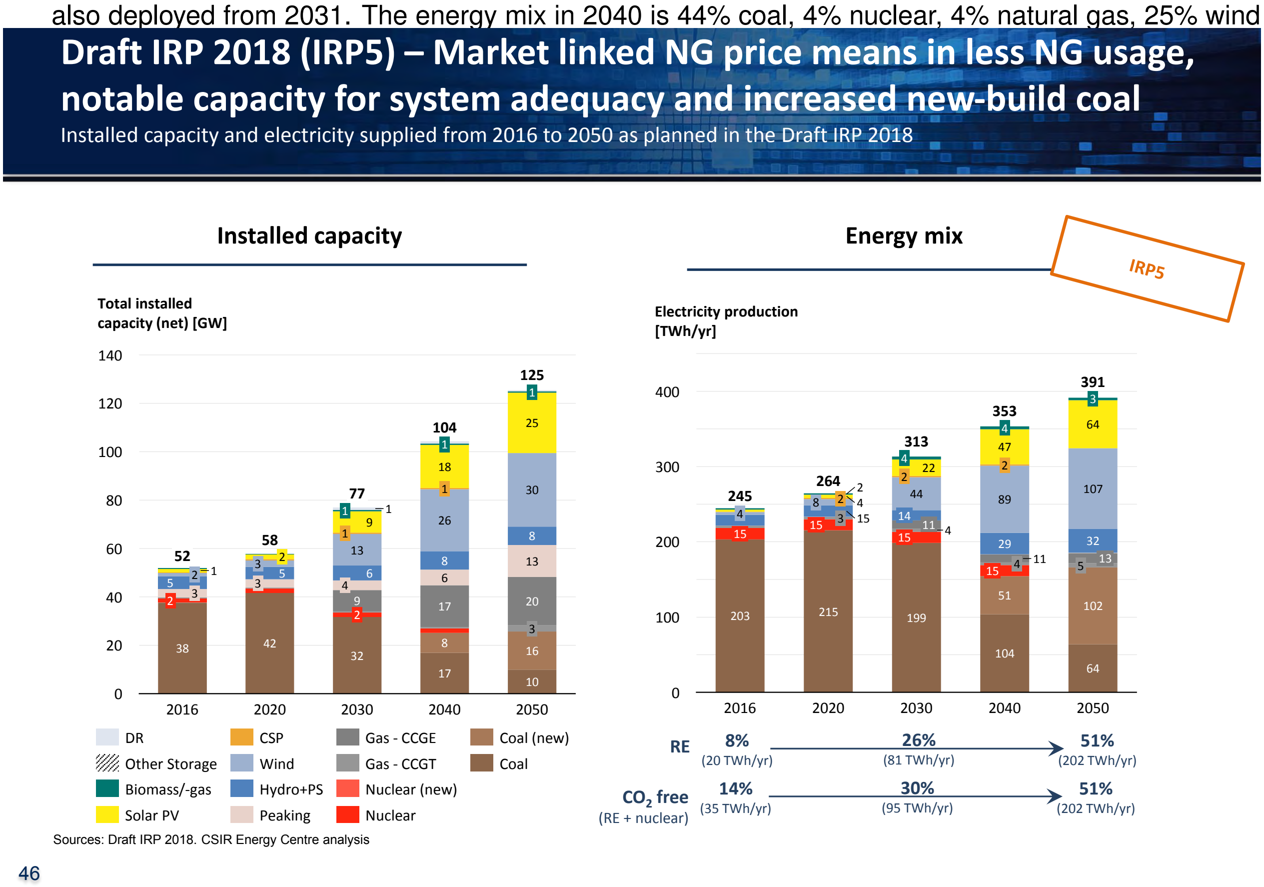


Figure 7: Installed capacity and energy mix for 2016-2050 from IRP5 in Draft IRP 2018

2.4 IRP6 (Carbon Budget)

The installed capacity and expected energy mix for the IRP6 scenario from the Draft IRP 2018 is summarised in Figure 8. Similar to IRP3 and IRP5, solar PV capacity and wind capacity is first deployed in 2024 and 2025 respectively and continues similarly to 2030 on a constrained deployment path. This results in a total of 9.3 GW and 13.0 GW of installed solar PV and wind by 2030. Flexible gas-fired capacity in the form of CC-GEs (2.3 GW) are first deployed in 2025. There is 250 MW of landfill gas built in 2029.

By 2030, coal still dominates the energy mix supplying a similar amount of energy as it did in 2016 and comprising 63% of the energy mix (≈200 TWh). Nuclear and hydro (mostly imported) also continue to play a similar notable role by 2030. The constrained deployment of wind and solar PV results in their energy share moving from <3% in 2016 to 21% of the energy mix by 2030. Natural gas capacity exists and is utilised in this scenario with 14.3 GW by 2030 (11.2 GW of CC-GEs and CCGT, 3.1 GW of OCGTs). The use of this capacity results in just less than 5% of the energy mix by 2030.

Beyond 2030, with a Carbon Budget implicitly constraining CO_2 emissions in this scenario, this is the first scenario where new-build nuclear capacity is deployed (first 1.4 GW by 2037) resulting in total capacity of 6.1 GW by 2040 and 7.0 GW by 2050. No new-build coal capacity is deployed until 2050 where 2.3 GW is deployed. Flexible gas-fired capacity deployment in this scenario is considerable by 2040 (22 GWCCGTs and CC-GE, 5.5 GW of OCGTs) and 2050 (30 GWCCGTs and CC-GE, 12 GW of OCGTs). Similar solar PV and wind are still deployed to 2040 and 2050 as in IRP3 and IRP5. Imported hydro (2.5 GW from Inga in DRC) is deployed from 2035. The energy mix in 2040 is 27% coal, 13%

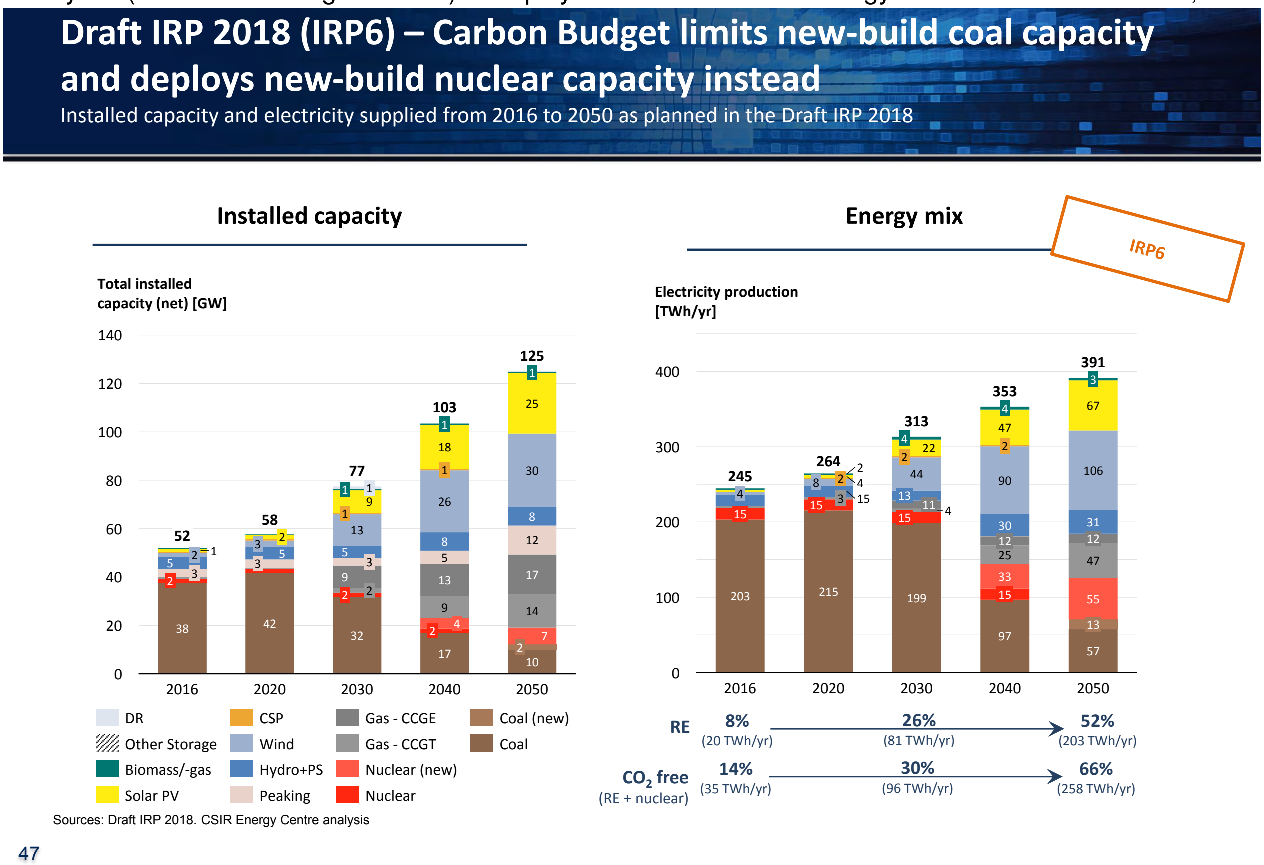


Figure 8: Installed capacity and energy mix for 2016-2050 from IRP6 in Draft IRP 2018

2.5 IRP7 (Carbon Budget and market-linked natural gas)

The installed capacity and expected energy mix for the IRP7 scenario from the Draft IRP 2018 is summarised in Figure 9. Similar to IRP3, IRP5 and IRP6; solar PV capacity and wind capacity is first deployed in 2024 and 2025 respectively and continues similarly to 2030 on a constrained deployment path. This results in a total of 8.9 GW and 13.0 GW of installed solar PV and wind by 2030. Flexible gas-fired capacity in the form of CC-GEs (2.3 GW) are first deployed in 2026 with peaking capacity in the form of OCGTs (0.1 GW) from 2028. There is 250 MW of landfill gas built in 2029. Imported hydro (2.5 GW from Inga in DRC) is deployed in 2030.

By 2030, coal still dominates the energy mix supplying a similar amount of energy as it did in 2016 and comprising 61% of the energy mix (≈190 TWh). Nuclear and hydro (mostly imported) also continue to play a similar notable role by 2030. The constrained deployment of wind and solar PV results in their energy share moving from <3% in 2016 to 21% of the energy mix by 2030. Relatively less natural gas capacity of 11.9 GW exists by 2030 (8.7 GW of CC-GEs and CCGT, 3.2 GW of OCGTs). The use of this capacity results in just less than 2% of the energy mix by 2030.

Beyond 2030, with a Carbon Budget and market linked natural gas price in this scenario, some new-build coal capacity is deployed (0.8 GW from 2033) and new-build nuclear capacity (first 1.4 GW by 2036) resulting in total coal and nuclear capacity of 18.4 GW and 7.5 GW by 2040 respectively. By 2050, coal and nuclear capacity is 14 GW and 9.8 GW respectively. Flexible gas-fired capacity deployment in this scenario is made up of 19.5 GW of CCGTs and CC-GE and 5.5 GW (OCGTs by 2040. By 2050, 24 GW of CCGTs and CC-GE and 13 GW of OCGTs are in existence in this scenario. Similar solar PV and wind are still deployed to 2040 and 2050 as in IRP3, IRP5 and IRP6. The energy mix in 2040 is

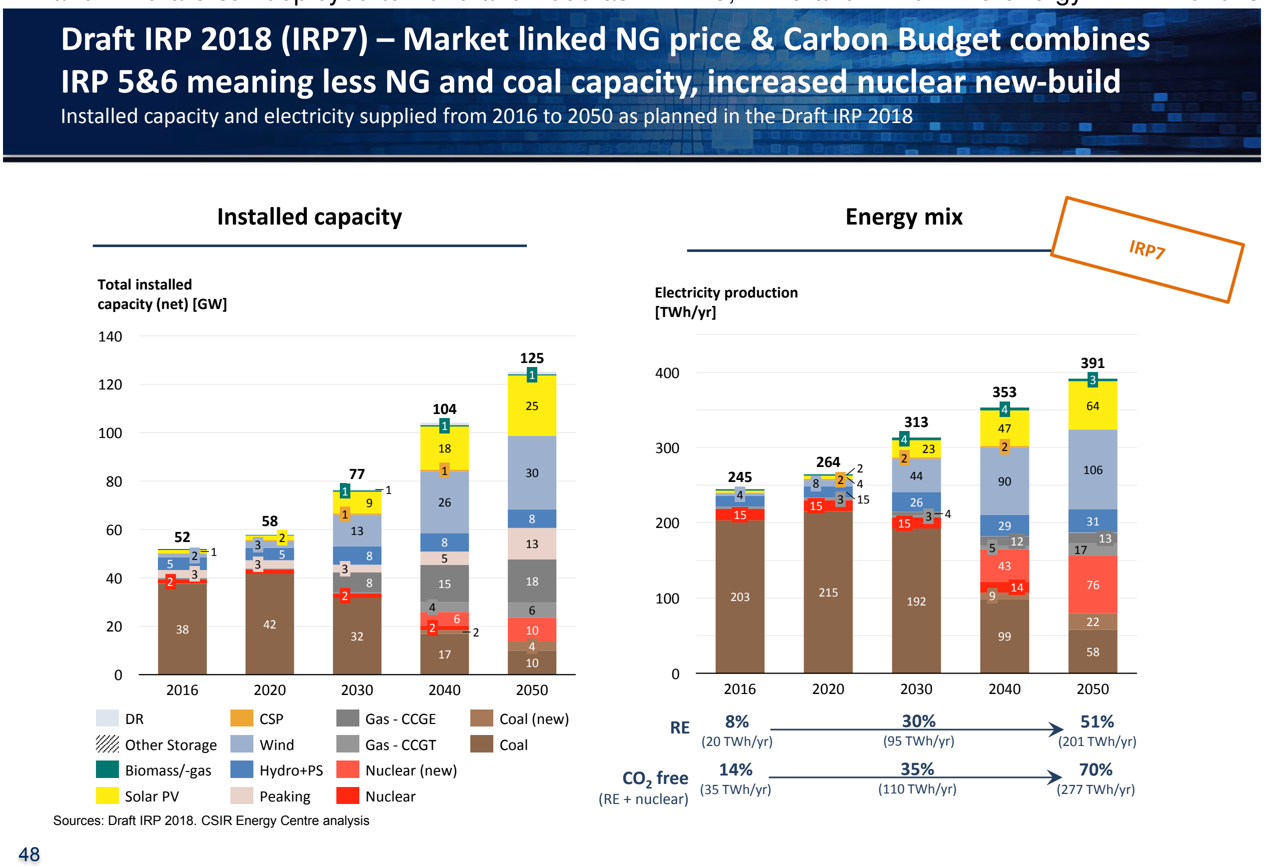


Figure 9: Installed capacity and energy mix for 2016-2050 from IRP7 in Draft IRP 2018

2.6 IRP2 (Upper demand forecast and new-build limits)

The installed capacity and expected energy mix for the IRP2 scenario from the Draft IRP 2018 is summarised in Figure 10. IRP4 is identical to IRP3 with only the demand forecast adjusted (to the IRP Upper demand forecast). New solar PV capacity and wind capacity is first deployed in 2024 and continues similarly to 2030 on a constrained deployment path. This results in a total of 9.3 GW and 13.6 GW of installed solar PV and wind by 2030. Flexible gas-fired capacity in the form of CC-GEs (1.7 GW) are first deployed in 2026 with peaking capacity in the form of OCGTs (0.3 GW) from 2030. There is 250 MW of landfill gas built in 2028. Imported hydro (2.5 GW from Inga in DRC) is deployed in 2030.

By 2030, coal still dominates the energy mix supplying a similar amount of energy as it did in 2016 and comprising 61% of the energy mix (≈200 TWh). Nuclear and hydro (mostly imported) also continue to play a similar notable role by 2030. The constrained deployment of wind and solar PV results in their energy share moving from <3% in 2016 to 20% of the energy mix by 2030. By 2030, 13.5 GW of natural gas capacity exists (10.2 GW of CC-GEs and CCGT, 3.3 GW of OCGTs). The use of this capacity results in 3% of the energy mix by 2030 being gas-fired.

Beyond 2030, some new-build coal capacity is deployed (0.8 GW from 2033) resulting in total coal capacity of 24.3 GW by 2040. By 2050, total coal capacity is 25 GW. The primary reason for the deployment of notable new-build coal capacity is as a result of the combination of a high demand forecast and annual new-build limits placed on solar PV and wind. Flexible gas-fired capacity deployment in this scenario is made up of 22 GW of CCGTs and CC-GE and 6.2 GW of OCGTs by 2040. By 2050, 33 GW of CCGTs and CC-GE and 9 GW of OCGTs are in existence in this scenario. The energy mix by 2040

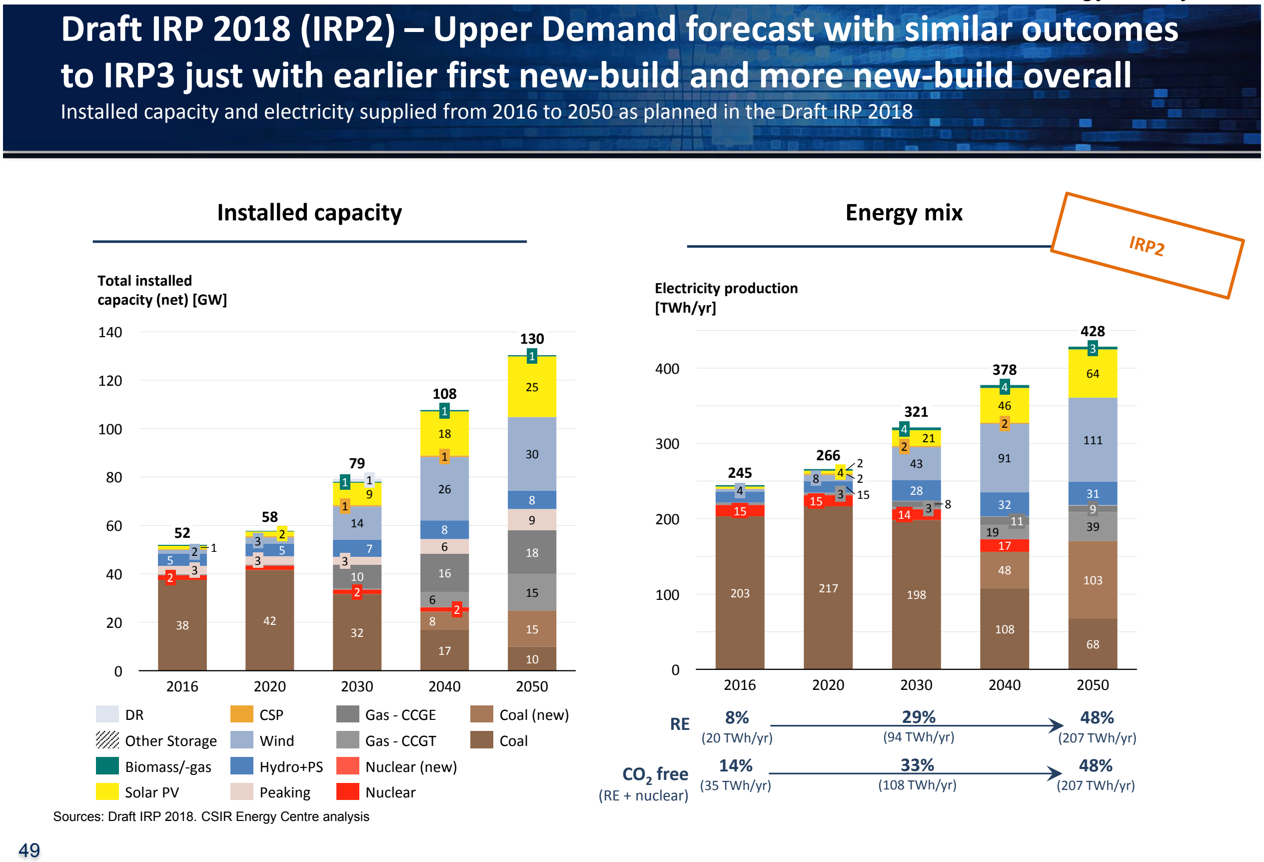


Figure 10: Installed capacity and energy mix for 2016-2050 from IRP2 in Draft IRP 2018

2.7 IRP4 (Lower demand forecast and new-build limits)

The installed capacity and expected energy mix for the IRP4 scenario from the Draft IRP 2018 is summarised in Figure 11. IRP2 is identical to IRP3 with only the demand forecast adjusted (to the IRP Lower demand forecast). New solar PV capacity and wind capacity is first deployed in 2026 and continues similarly to 2030 on a constrained deployment path. This results in a total of 9.3 GW and 13.6 GW of installed solar PV and wind by 2030. Flexible gas-fired capacity in the form of CC-GEs (0.3 GW) and OCGTs (0.3 GW) are first deployed in 2027. There is 250 MW of landfill gas built in 2029.

By 2030, coal still dominates the energy mix supplying a similar amount of energy as it did in 2016 and comprising 67% of the energy mix (≈190 TWh). Nuclear and hydro (mostly imported) also continue to play a similar notable role by 2030. The constrained deployment of wind and solar PV results in their energy share moving from <3% in 2016 to 17% of the energy mix by 2030. Also by 2030, 10.9 GW of natural gas capacity exists (7.5 GW of CC-GEs and CCGT, 3.5 GW of OCGTs). The use of this capacity results in 5% of the energy mix by 2030 being gas-fired.

Beyond 2030, some new-build coal capacity is deployed (1.5 GW from 2037) resulting in total coal capacity of 22.1 GW by 2040. By 2050, total coal capacity is 18.1 GW. The primary reason for the deployment of new-build coal capacity is as a result of the moderate Peak Plateau Decline (PPD) CO_2 emissions limit combined with the annual new-build limits placed on solar PV and wind. Flexible gas-fired capacity deployment in this scenario is made up of 22 GW of CCGTs and CC-GE and 6.2 GW of OCGTs by 2040. By 2050, 33 GW of CCGTs and CC-GE and 9 GW of OCGTs are in existence in this

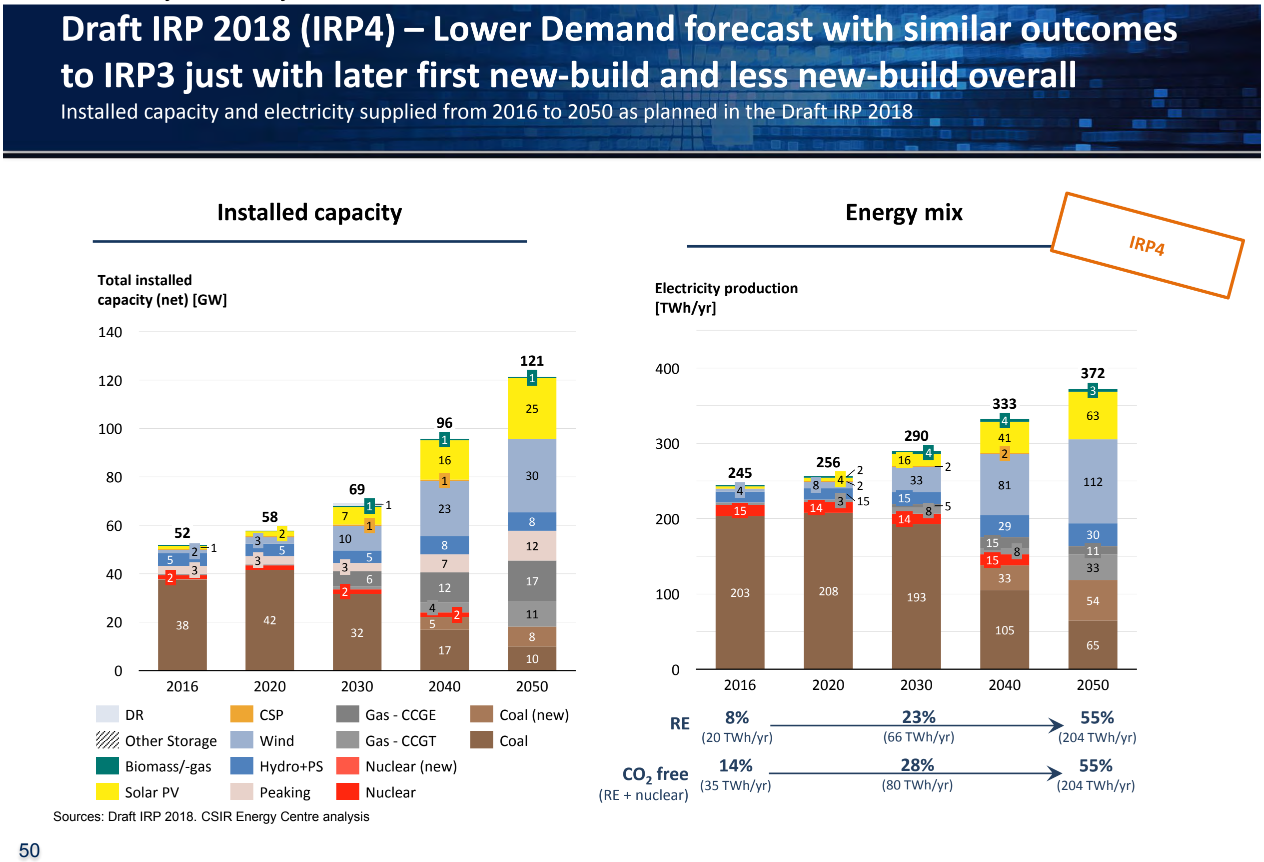


Figure 11: Installed capacity and energy mix for 2016-2050 from IRP4 in Draft IRP 2018

2.8 DoE Recommended Plan

The installed capacity and energy mix of the Recommended Plan from the Draft IRP 2018 is shown in Figure 12. The Recommended Plan stops at 2030 and does not extend beyond to the time horizon of the other scenarios considered (2050). The primary reason for this, as cited by the DoE, is that of increased levels of uncertainty beyond 2030 in a number of dimensions [26].

The Recommended Plan maintains new-build constraints on solar PV and wind whilst including policy

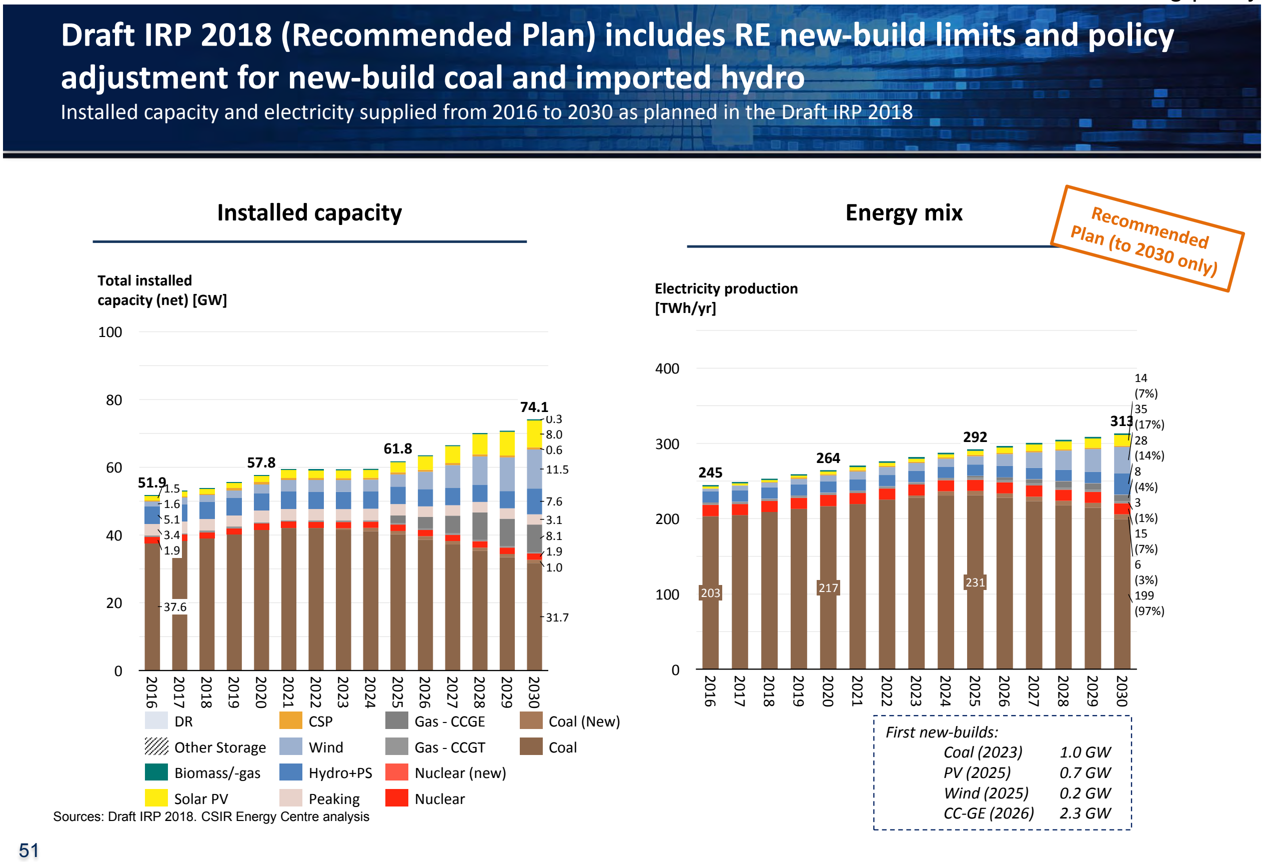


Figure 12: Installed capacity and energy mix for 2016-2050 from Recommended Plan in Draft IRP 2018

2.9 Summary

Summaries of all of the Draft IRP 2018 scenarios for 2030, 2040 and 2050 are provided in Figure 13-15. By 2030, the energy mix is still quite similar across most scenarios with coal remaining the dominant energy supplier supplying more than 60% of the energy mix. The IRP1 (Least-cost) scenario is ≈R15bn/yr cheaper than the most expensive scenario by 2030 (the Recommended Plan followed closely by IRP7). However, IRP7 does exhibit the lowest CO_2 emissions by 2030 (207 Mt relative to 213-217 Mt in other scenarios). Beyond 2030 to 2040, the least-cost mix is confirmed via IRP1 to be new-build solar PV, wind and flexible natural gas fired capacity. The IRP1 scenario is ≈R15-55 bn/yr cheaper than the alternative scenarios by 2040. By 2050, the Least-cost mix in IRP1 is 70% solar PV and wind, is ≈R30-60 bn/yr cheaper than alternative scenarios, exhibits the lowest least CO_2 emissions and the least water usage.

It is important to note that all scenarios except IRP1 include annual new-build limits on solar PV and wind with no justification provided yet. In addition, all scenarios assume a Moderate EAF of the existing coal fleet.

There are also not no notable new or innovative technologies like stationary storage or DSR options considered in any scenarios.

Assumptions considered for technology learning for coal (with CCS), wind, solar PV, CSP and nuclear are relatively conservative.

There is no scenario in which the existing fleet (dominated by coal capacity) is freely optimised and

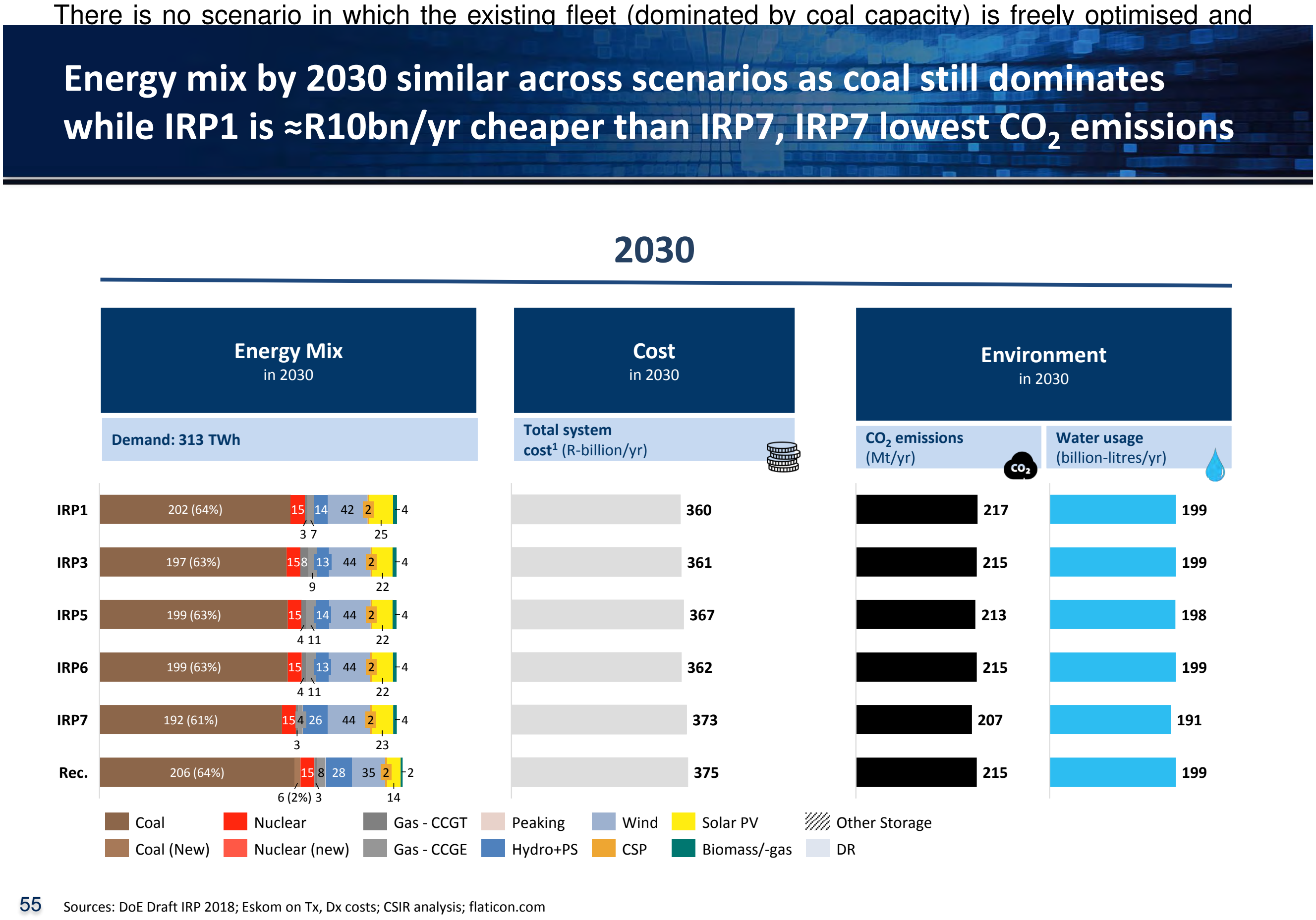
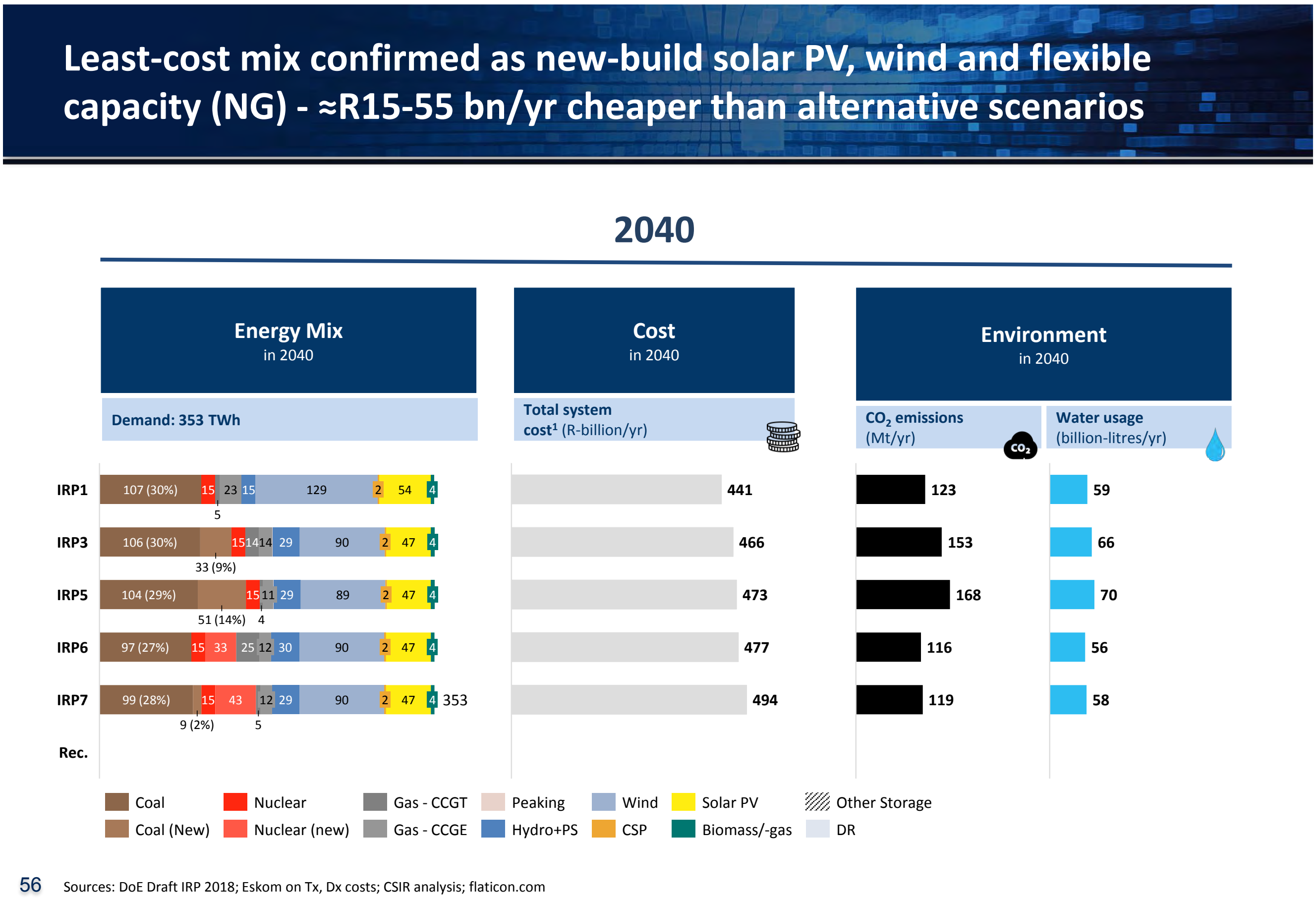


Figure 13: Summary of energy mix, system costs, CO_2 emissions and water usage for Draft IRP 2018 scenarios (2030)



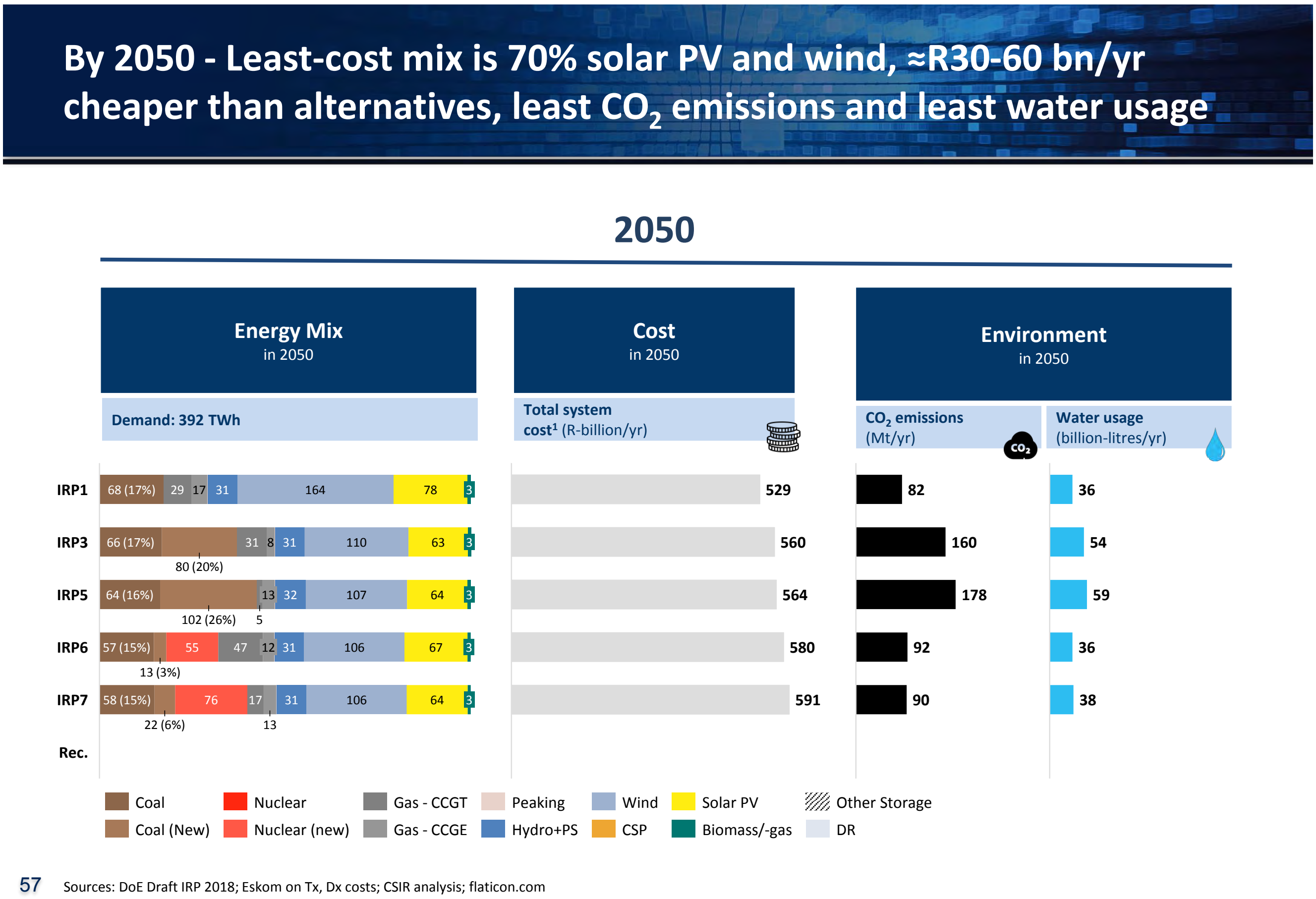


Figure 15: Summary of energy mix, system costs, CO_2 emissions and water usage for Draft IRP 2018 scenarios (2050)

A summary of the expected CO_2 emissions and water usage for the range of scenarios considered in the Draft IRP scenarios is provided in Figure 16.

Across all scenarios, electricity sector CO_2 emissions are expected increase slightly towards the middle of the 2020s following which all decrease (some scenarios exhibiting further reductions than others). Interestingly, a similar effect on CO_2 emissions is noted for IRP6 and IRP7 (where a strict Carbon Budget combined with a market linked natural gas price is applied) to that seen in the IRP1 scenario (Least-cost). The deployment of nuclear capacity in drive CO_2 emissions to similar levels seen in the least-cost IRP1 scenario. The Least-cost scenario (IRP1) shows CO_2 reductions to 217 Mt by 2030, 123 Mt by 2040 and 83 Mt by 2050. IRP2 and IRP5 exhibit the highest CO_2 emissions trajectories as considerable new-build coal capacity is built - driven by the PPD Moderate limit not binding and the annual new-build limits on solar PV and wind. IRP3 and IRP4 also show similar moderate CO_2 emissions trajectories as some new-build coal capacity is built due to the combined effect of a Lower demand forecast (IRP4) and annual new-build limits on solar PV and wind.

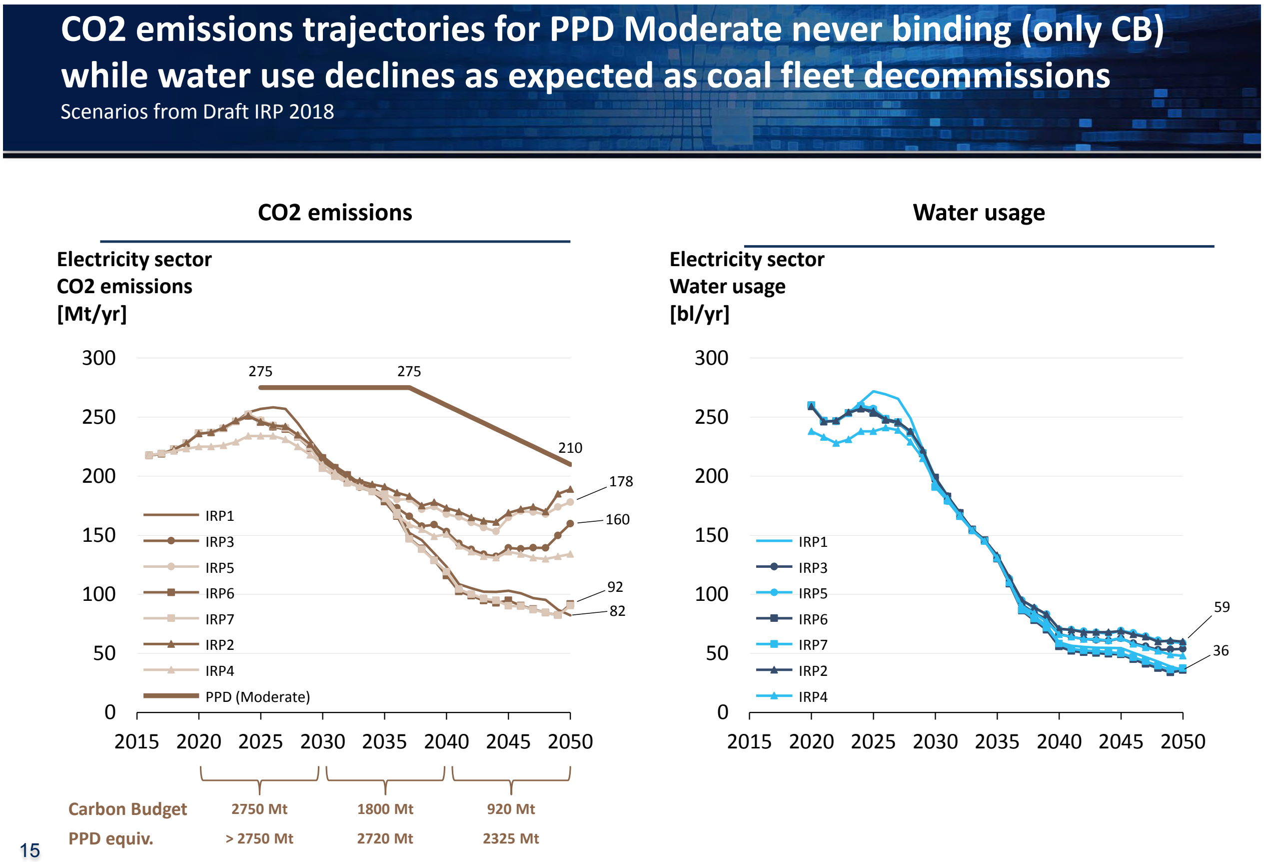
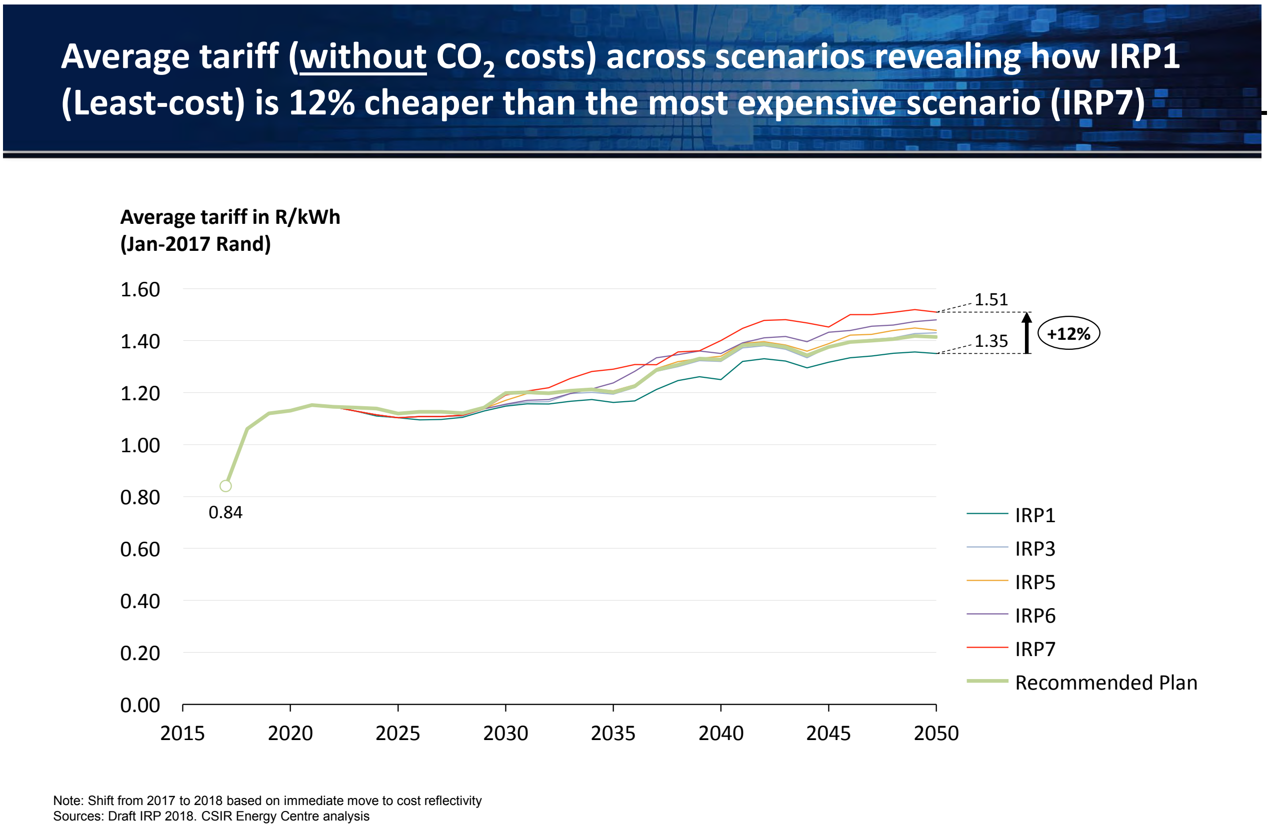


Figure 16: Electricity sector CO_2 emissions and water usage for the range of Draft IRP 2018 scenarios

The expected average tariff trajectories as well as total system costs for the range of scenarios considered in the Draft IRP 2018 are shown in Figure 17 and 18 respectively. There is a notable shift from the starting year where an average tariff of 0.84 R/kWh moves immediately to 1.06 R/kWh. Clarity on this step change is not yet publicly available but is is assumed that this is likely due to an immediate shift towards cost reflectivity. The average tariff in the IRP1 (Least-cost) scenario ends up being 12% lower than the most expensive scenario considered (IRP7). Total system costs for the IRP1 scenario is ≈R60-bn/yr cheaper than IRP7 by 2050.



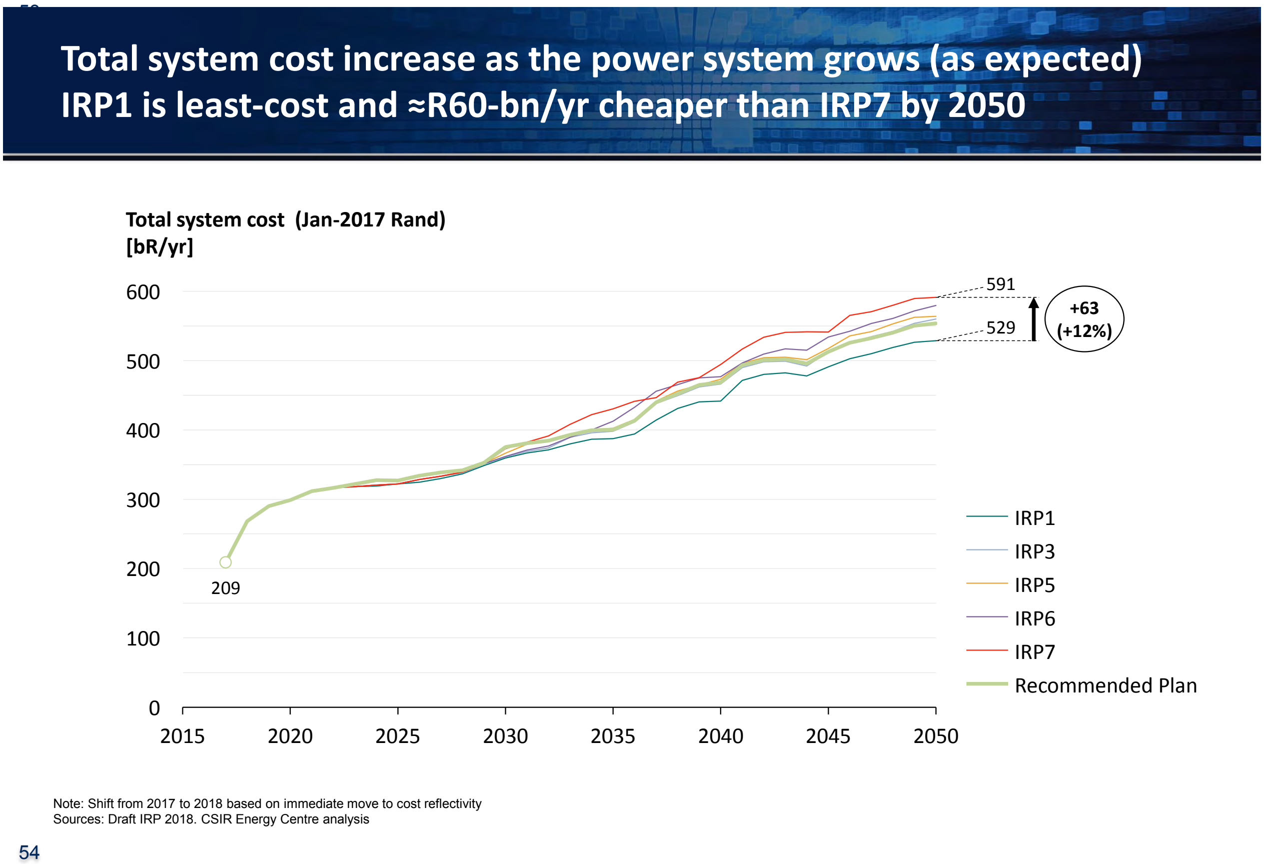


Figure 18: Expected total system costs for the range of Draft IRP 2018 scenarios (IRP1, IRP3, IRP5, IRP6, IRP7)

3 Draft IRP 2018 Employment Impacts

3.1 Approach

The approach in the set of Jobs and Economic Development Impacts (JEDI) models developed by National Renewable Energy Laboratory (NREL) [27] has been customised for application to the South African environment by CSIR to create an International Jobs and Economic Development Impacts (I-JEDI) model for South Africa for a range of technologies. The JEDI model is a freely available economic tool to understand expected economic changes at a high-level for energy technology choices. These impacts are highlighted by particular parameters including job creation potential, Gross Domestic Product (GDP) impact and household income.

I-JEDI estimates economic impacts by characterising construction and operation of energy projects in terms of expenditures and portion of these made within the country (the component that is localised). These are then used in the country-specific input-output model to estimate employment, earnings and GDP.

The I-JEDI model for South Africa is applied at a national level to a range of selected technologies for selected scenarios of the Draft IRP 2018 [2]. The power generation technologies included in the analyses include:

- Coal;
- Onshore wind;
- Solar PV; and
- Natural gas
- Embedded Generation (assumed to be distributed solar PV)

The direct, indirect and induced employment potential for each of the above technologies (electricity sector driven only) can be determined using the customised I-JEDI tool. Simply put, these can be characterised as (based on [28]):

- **Direct:** People employed by the power generation project itself.
- **Indirect:** People employed by supplying goods and services to the power generation project [28].
- **Induced:** People employed to provide goods and services to meet consumption demands of additional directly and indirectly employed workers.

[2]This is purely owing to the status-quo dominance of these technologies and expected deployment in Draft IRP 2018 scenarios. It is also condensed due to the limited time available as part of the 60 day public consultation period.

Technologies not included at this stage are nuclear, hydro, Concentrated Solar Power (CSP) and biomass/-gas. These should be further explored in future in order to obtain a holistic view of all technologies when utilising the I-JEDI approach.

An indicative inclusion of direct, indirect and induced operations jobs in nuclear is also provided for reference based on [29].

3.2 Outcomes

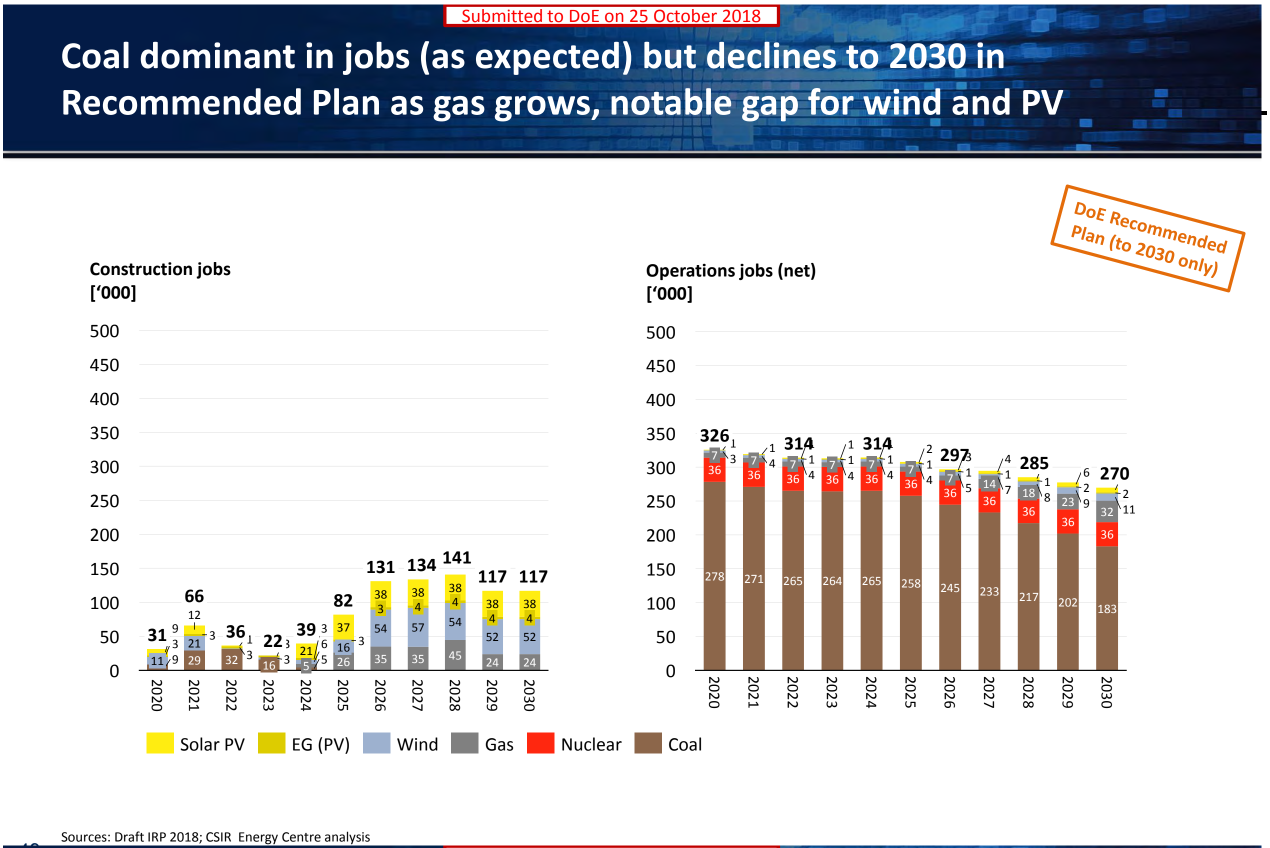
3.2.1 Employment potential (Recommended Plan)

As an initial contribution to the expected shifting away from coal for power generation in most scenarios of the Draft IRP 2018, an analysis of the employment potential for the Recommended Plan (described in section 2.8) is provided in this section. The CSIR intends to undertake further analysis on other scenarios of the Draft IRP 2018 as well as other long-term energy planning outcomes but due to limited time has not been able to complete a further comprehensive analysis at this stage.

The construction and operations employment potential for the Draft IRP 2018 Recommended Plan are shown separately in Figure 19 and then summarised in Figure 20. Employment potential includes direct, indirect and induced jobs. The overall net growth in potential jobs for the Recommended Plan of the Draft IRP 2018 is expected as a result of the increase in absolute size of the South African power system to 2030.

As shown in Figure 21 and 22, even with the inclusion of 1000 MW of new-build coal capacity as part of this scenario, the decommissioning of a notable component of the existing coal fleet (9.9 GW between 2020 and 2030) dominates and results in an expected reduction of jobs in coal of ≈100 000 to 2030. However, the deployment of new-build natural gas capacity as part of this scenario results in ≈60 000 jobs towards 2030 whilst VRE deployment (solar PV and wind) contributes up to ≈110 000 jobs by 2030.

For context, it is important to put these employment numbers into perspective. The utilities sector (electricity, water, oil & gas) makes up ≈0.6-0.9% of employment in South Africa [30, 31, 32, 33, 34]. This supports the reality that employment is created in a range of sectors in the economy (not just in the utilities sector) with energy largely seen as an enabler for economic development and employment.



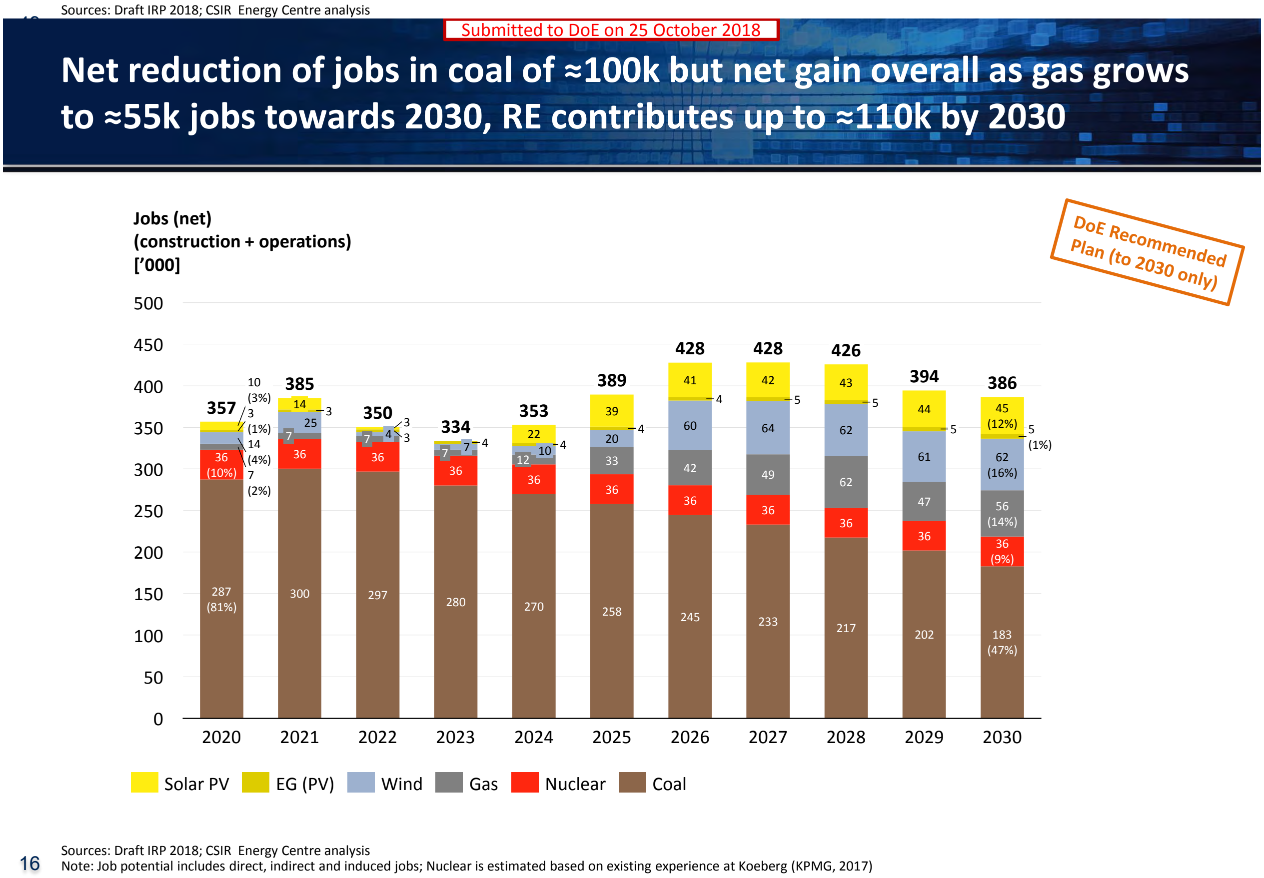
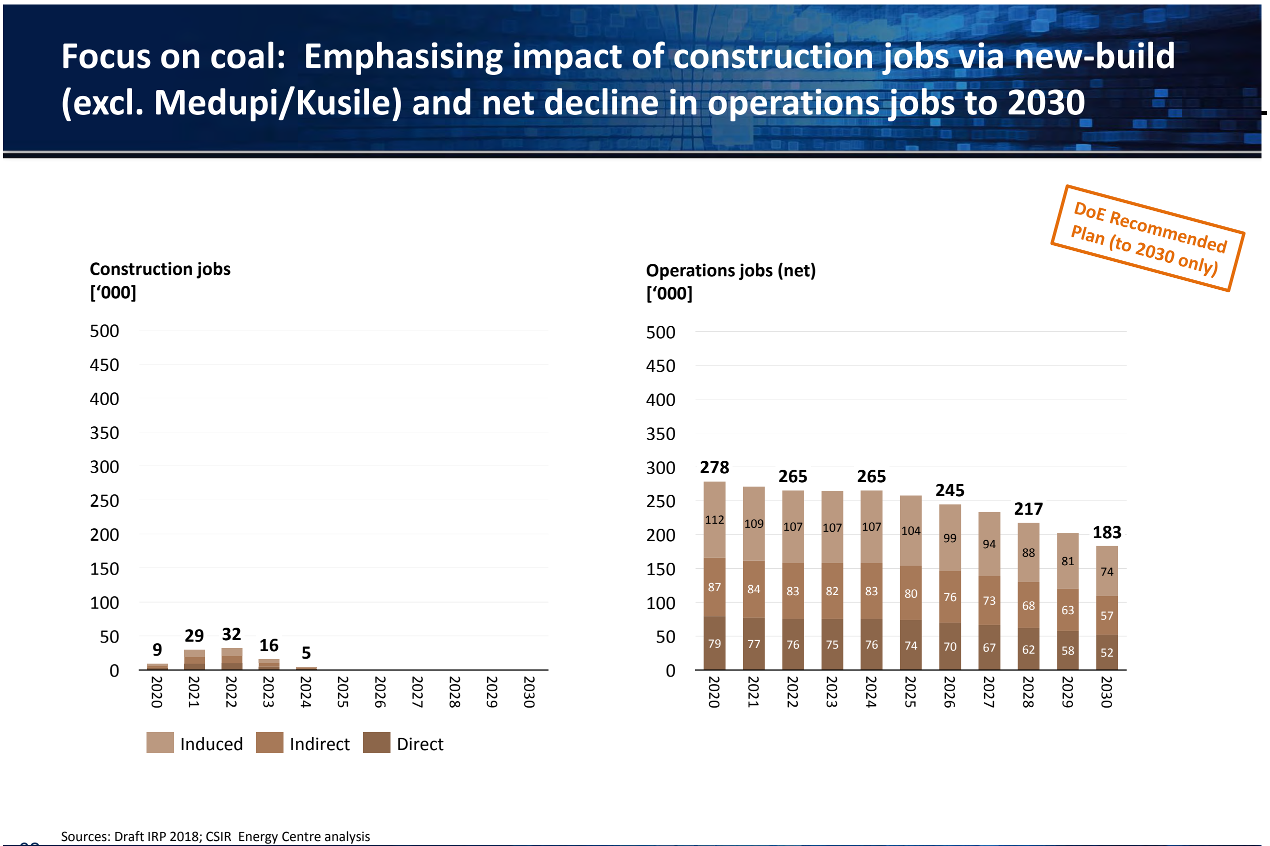


Figure 20: Total jobs (combined construction and operations) for the Recommended Plan of Draft IRP 2018



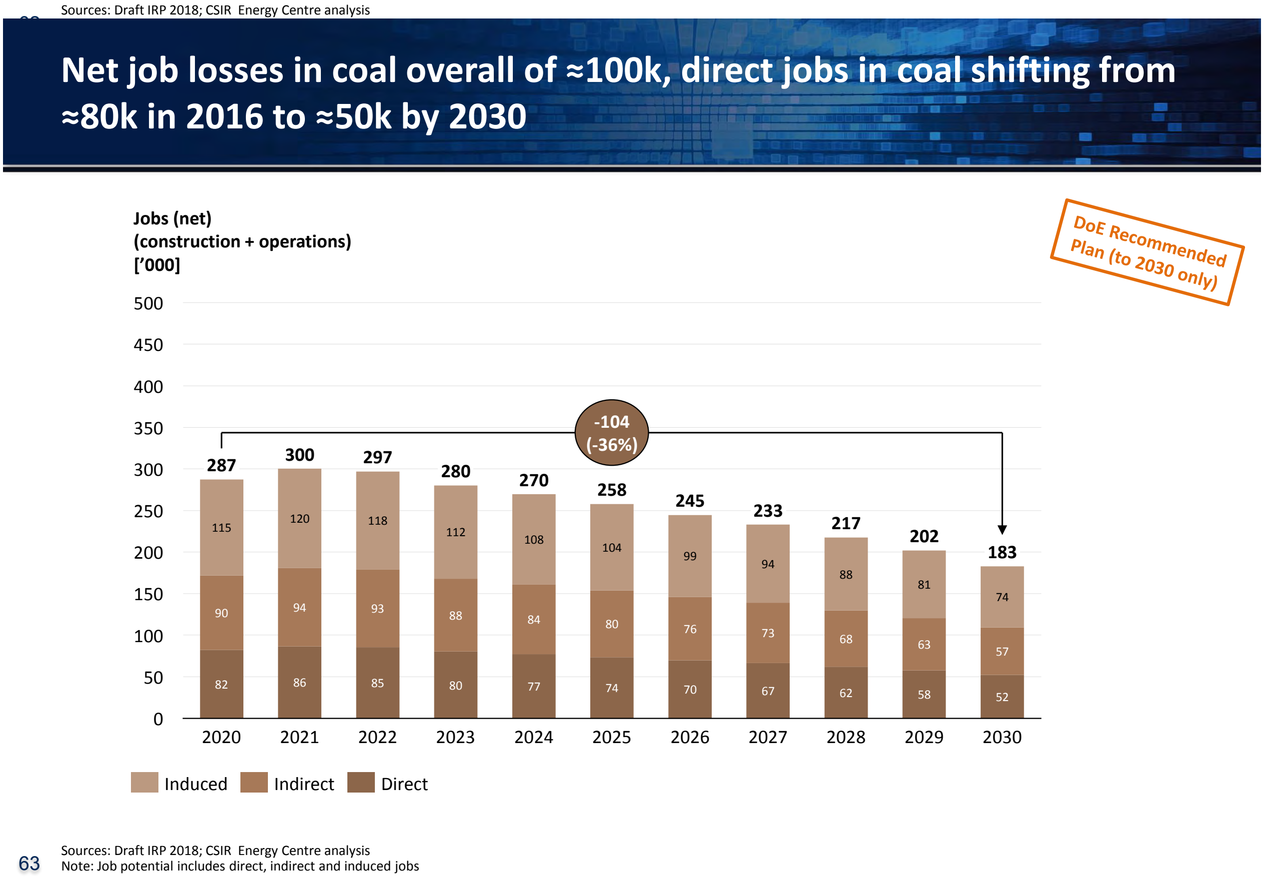


Figure 22: Total jobs for coal (combined construction and operations) for the Recommended Plan of Draft IRP 2018

4 Draft IRP 2018 energy planning risks and opportunities

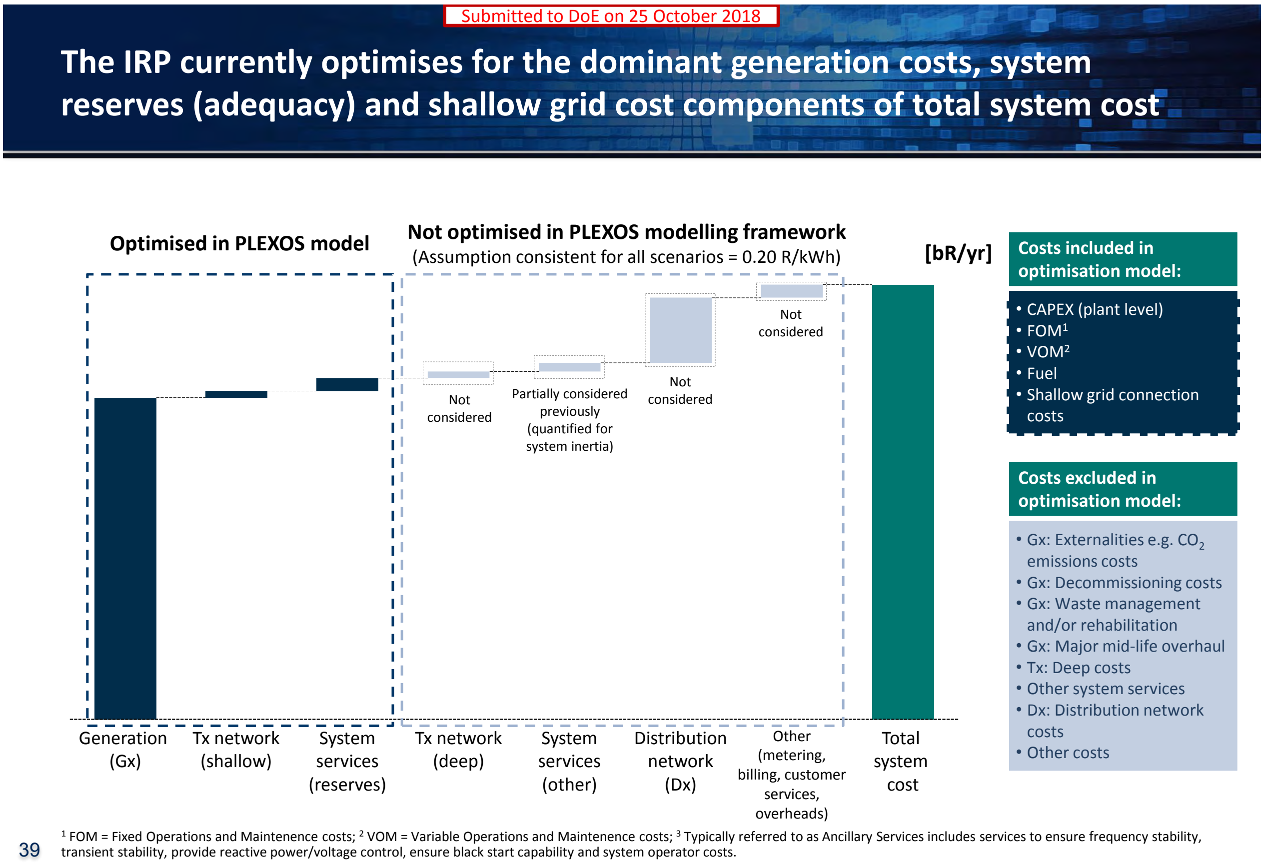


Figure 23: Current IRP approach in South Africa includes the dominant cost drivers as part of the energy planning approach

4.1 Scenarios

For consistency, the key dimensions upon which scenarios considered in this section are considered are aligned with those documented by the DoE in the Draft IRP 2018. That is:

- Net installed generation capacity (per technology) - [MW];
- Production of energy (per technology) - [TWh];
- Total system cost - [ZAR-billion];
- CO_2 emissions - [Mt/yr]; and
- Water usage - [bl/yr]

As mentioned in section 2, clarity on the step change in average tariff in the Draft IRP 2018 between 2017 and 2018 is not yet publicly available. For the analyses undertaken here, the starting point in 2016 consists of the primary cost drivers included as part of the modelling approach (see Figure 23) following which a pre-defined tariff adder is included to align with the known 0.84 ZAR/kWh average effective tariff in 2016. Following this, from 2017 to 2018, the jump from 0.84 ZAR/kWh to 1.06 ZAR/kWh is understood to be representative of an immediate shift to cost reflectivity i.e. an additional 0.21 ZAR/kWh. This is also kept throughout the time horizon in order to remain consistent for comparative purposes with the Draft IRP 2018. This is deemed acceptable if a relative comparison between scenarios is made (which is the case in this submission).

4.1.1 Impact of stationary storage

4.1.1.1 Scenario description

Stationary storage technologies have been included in the Draft IRP 2018 in the form of Lithium-ion batteries (1 hour and 3 hour storage capacity) as well as Compressed Air Energy Storage (CAES). The Draft IRP 2018 assumed no cost reductions for these technologies. This results in no stationary storage present in any of the Draft IRP 2018 scenarios.

The stationary storage scenario is defined by the following input assumptions:

- *Demand forecast:*	Median (IRP 2018)
- *Supply technologies costs:*	IRP 2018 with learning for storage
- *Supply technologies new-build limits:*	None
- *DSR:*	None
- CO_2 *emissions trajectory:*	PPD (Moderate)
- *Existing fleet performance:*	IRP 2018 (Moderate)
- *Existing fleet decommissioning:*	IRP 2018
- *System adequacy (reserves):*	Eskom (to 2022), assumed thereafter

This scenario aims to demonstrate the impact of stationary storage on the IRP1 scenario when learning rates are assumed for stationary storage. The assumed learning rates are summarised in Figure 24 (based on a number of international forecasts [17]–[19]). The assumed cost reductions for stationary storage is that costs will decline to 200 USD/kWh by 2030, 150 USD/kWh by 2040 and 100 USD/kWh by 2050.

Figure 24: Overnight capital cost of stationary storage (excludes pumped storage) considered for the stationary storage scenario

4.1.1.2 Outcomes

The results summary for the stationary storage scenario is shown in Figure 25. The stationary storage scenario results in no new coal or nuclear investment (similar to the IRP1 scenario). By 2030, the least-cost mix consists of new gas capacity, stationary storage, solar PV and wind investments. Stationary storage in the form of 1 hour and 3 hour storage capacity is deployed from 2027 onwards. Import hydro is cost optimal from 2039. By 2050, 18% of the energy mix is coal (all existing) complemented by gas (13%), hydro (8%), wind (39%), solar PV (21%) and biomass/-gas making up the remainder.

Figure 26 shows the difference in installed capacity and energy mix in the stationary storage scenario relative to IRP1. It can be seen that the impact of storage technology cost declines on the IRP1 scenario results in a larger share of renewable energy from solar PV relative to wind and a notably lower deployment of gas capacity. The energy share of solar PV relative to wind increases from 35% solar PV / 65% wind to 40% solar PV / 60% wind by 2030 and the energy share of gas decreases by 1% by 2030 and 5% by 2050 relative to IRP1.

Given the higher uptake of solar PV in this scenario before and after 2030, the annual new build limit of 1 000 MW/yr for solar PV applied in most Draft IRP 2018 scenarios would increase total system cost further if storage costs decline as expected. There is no change in timing of the first new build capacity.

The value of stationary storage analysed is purely that of energy arbitrage. Other value streams that stationary storage could further add for the system include network deferral or avoidance and ancillary services provision (reactive power and voltage control).

Figure 27 shows the CO_2 and water usage for the stationary storage scenario. It can be seen that there is only a marginal difference in CO_2 and water usage relative to the IRP1 scenario prior to 2030 with a slightly higher decline in CO_2 by 2050. Figure 28 shows the total system cost of the stationary storage scenario relative to the IRP scenario. It can be seen that IRP1 with storage cost declines is ≈R8-bn/year less expensive by 2050 than IRP1, while the cost difference is minimal before 2030.

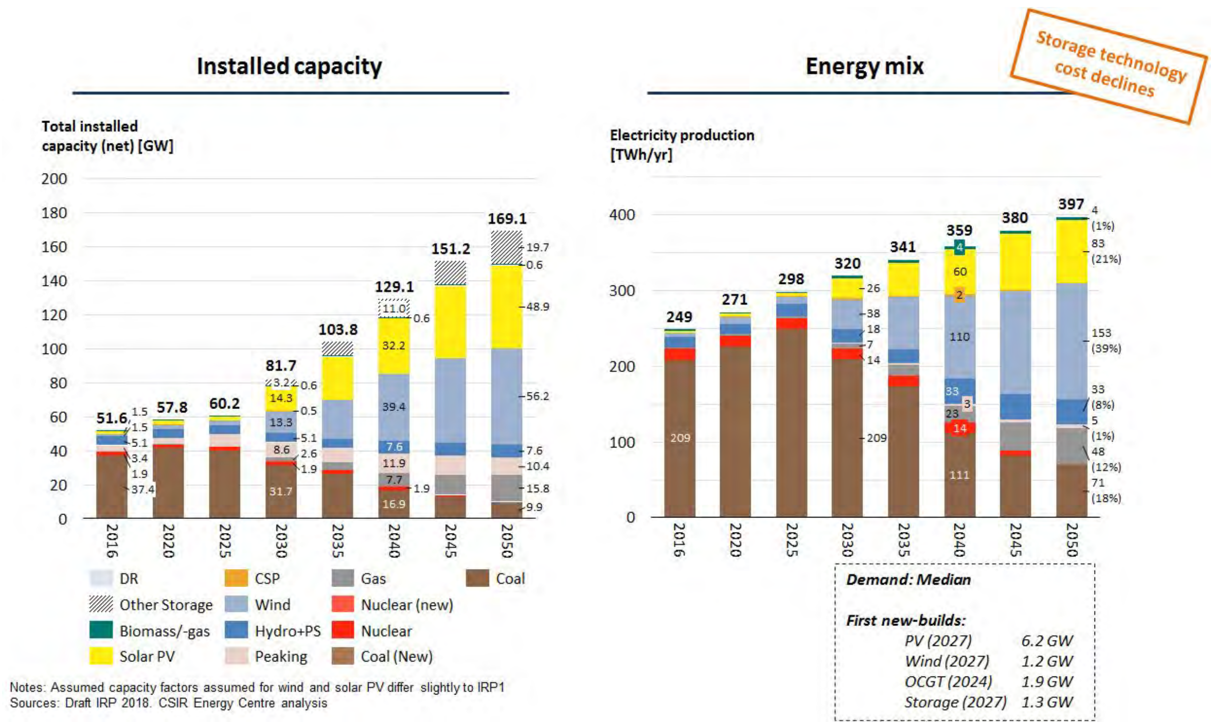


Figure 25: Installed capacity and energy mix for the stationary storage scenario

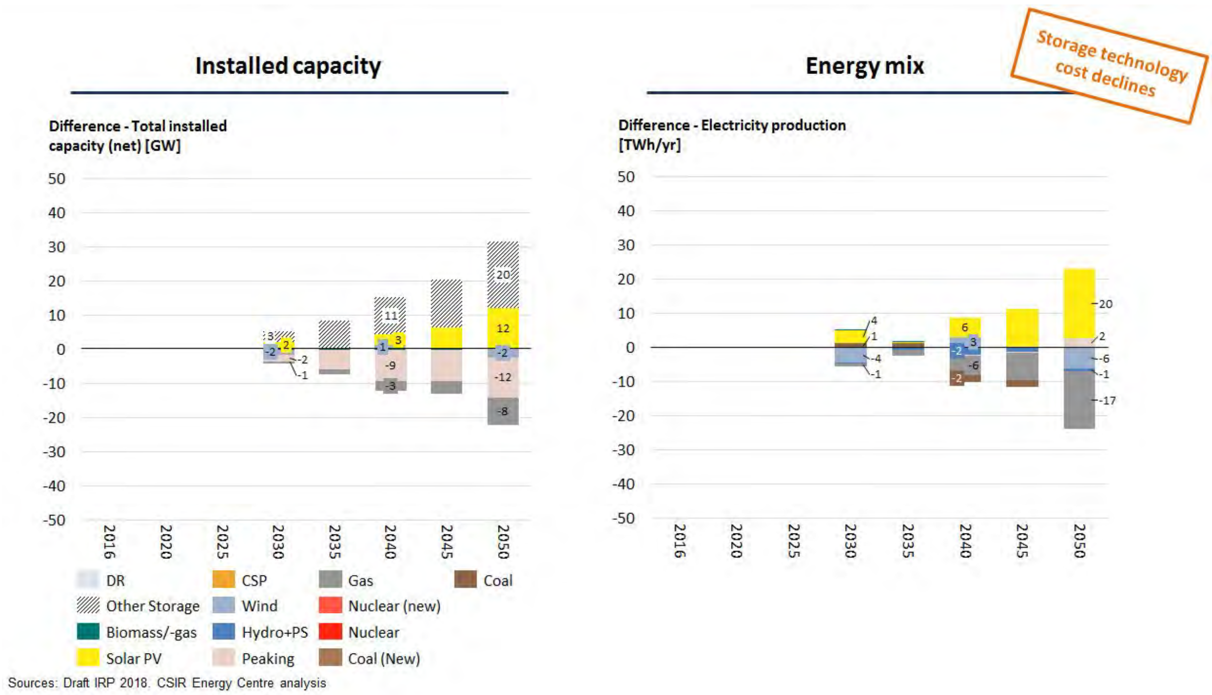


Figure 26: Difference in installed capacity and energy mix in the stationary storage scenario relative to IRP1

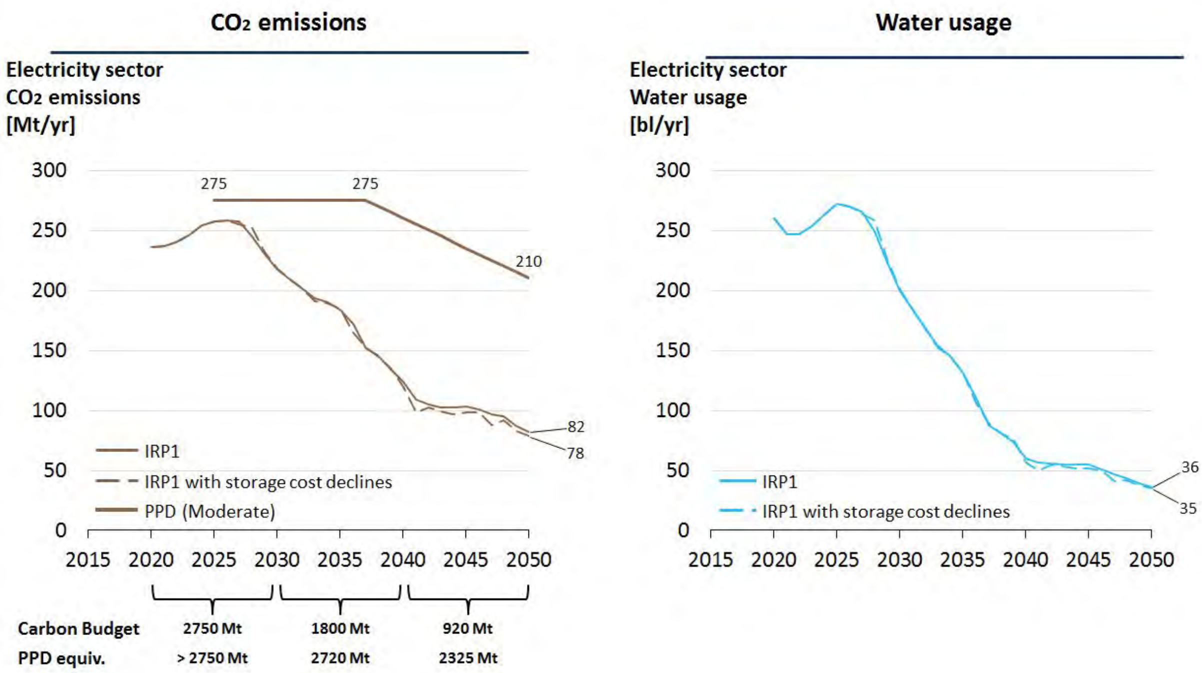


Figure 27: Emission and water trajectories for the IRP1 and stationary storage scenarios

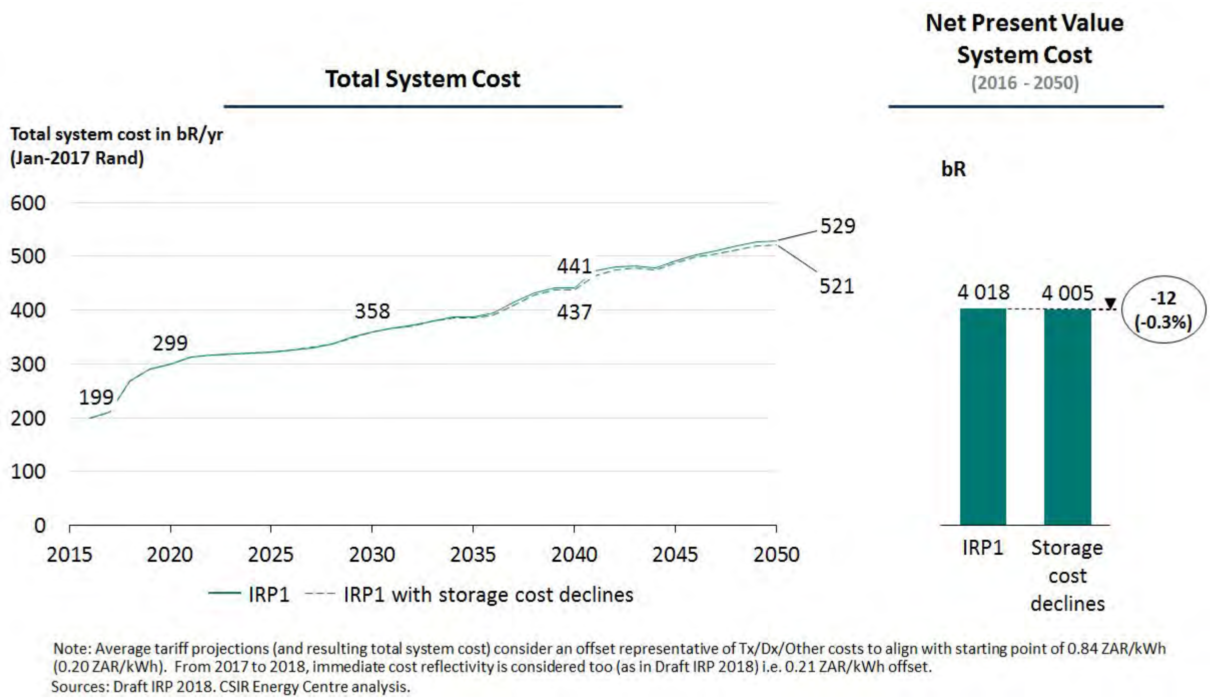


Figure 28: Total system costs for the IRP1 and stationary storage scenarios

4.1.2 Impact of DSR

4.1.2.1 Scenario description

Demand Side Response (DSR) has not been explicitly included in the Draft IRP 2018 scenarios. Thus, similar to previous comments provided by the CSIR as part of the Draft IRP 2016, this is explored here in the form of EWHs and electric vehicles (Private Light-Duty Vehicles (PLDVs)). DSR is considered by augmenting the IRP1 scenario with EWHs and demand flexibility from PLDVs.

The DSR scenario is defined by the following input assumptions:

- *Demand forecast:*	Median (IRP 2018)
- *Supply technologies costs:*	IRP 2018
- *Supply technologies new-build limits:*	None
- *DSR:*	EWHs & e-vehicles
- CO_2 *emissions trajectory:*	PPD (Moderate)
- *Existing fleet performance:*	IRP 2018 (Moderate)
- *Existing fleet decommissioning:*	IRP 2018
- *System adequacy (reserves):*	Eskom (to 2022), assumed thereafter

4.1.2.2 Demand flexbility: Electric Water Heatings (EWHs)

Although there are many opportunities for demand shaping in a number of end-use sectors (domestic, industrial, commercial), the intention of including one particular demand shaping opportunity is to demonstrate the impact that this can have on the power system. Specifically, demand shaping in the residential sector with a particular focus on the intra-day control of residential EWH demand i.e. control of EWHs. This has been investigated and reviewed for a range of end-use appliances in [35, 36] but specifically for EWHs in [37, 38, 39] (amongst others). In the South African context for example; a simple, low-cost and easy to implement distributed control method paradigm for EWH using system frequency as an input signal has been proposed in [40].

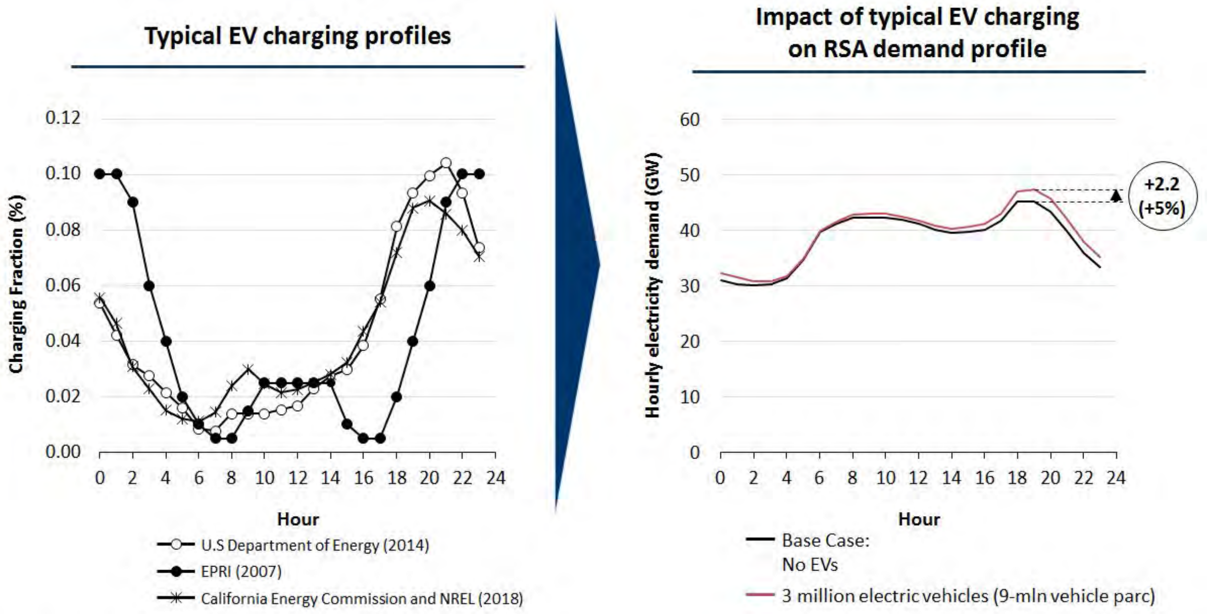
The modelling of residential EWH as a demand shaping resource is kept as simple as possible while basing the fundamentals on empirical existing data and likely future adoption. A summary of key parameters which define the EWH resource for demand shaping are given in Table 2 adapted from previous work done by the CSIR in [7, 8] while a brief description of the approach follows. For calibration purposes, the share of residential end-use in total electrical energy demand is determined along with the typical EWH component of this based on information from the South African Audience Research Foundation (SAARF) All Media and Products Survey (AMPS) Survey, Eskom and CSIR [41, 42, 43]. The population growth from [42], number of households from StatsSA [44], estimates for the number of people per household and the expected number of households with EWHs are then used to obtain the future expected number of households as well as households with EWHs in South Africa. From this (and the previous calibration performed), a range of parameters including an assumed adoption rate of demand shaping from EWHs, capacity of electric water heating elements over time determine the EWHs resource available to shape demand on an intra-day basis. It is assumed that there is no substitution effect (energy demand needs to be met on a daily basis but can be shifted depending on system requirements). Although demand shaping could strictly be included as a capacity resource that contributes to system adequacy [45, 46]; the authors assume no capacity value for EWHs demand shaping i.e. a conservative approach is taken.

Table 2: Input parameters and calculations for EWH demand shaping over the time horizon 2016-2050

Property	Unit	2016-2019	2020	2030	2040	2050
Population	[mln]	55.7 - 57.5	58.0	61.7	64.9	68.2
Number of HHs	[mln]	16.9 - 18.1	18.5	22.4	26.0	27.3
Residents per HH	[ppl/HH]	3.29 - 3.17	3.13	2.75	2.50	2.50
HHs with EWH	[%]	28 - 33	34	50	75	100
HHs with EWH	[mln]	4.7 - 5.9	6.3	11.2	19.5	27.3
Demand shaping adoption	[%]	-	2	25	100	100
Demand shaping	[TWh/a]	-	0.4	5.4	28.3	26.4
Demand shaping	[GWh/d]	-	1.1	14.9	77.4	72.3
Demand shaping (demand increase)	[MW]	-	371	4 991	25 970	24 265
Demand shaping (demand decrease)	[MW]	-	46	620	3 226	3 015

4.1.2.3 Demand flexibility: e-vehicles

Similar to the approch taken for a demand shaping resource for EWHs, electric vehicles (e-vehicles) are included as a flexible demand side option in the DSR scenario. This will also demonstrate the impact on the power system as more e-vehicles make up the South African vehicle fleet. Figure 29 shows three weekday aggregated electric vehicle charging profiles adapted from the California Energy Commission [47], the U.S Department of Energy [48] and EPRI [49]. The majority of e-vehicle charging of PLDVs occurs during off-peak hours. Additionally, the impact on the shape of the demand profile resulting from a large number of e-vehicles (3-million) is demonstrated for a hypothetical day in future where it can be seen that there is an increase in the evening peak demand and night-time demand. The impact is however relatively small compared to the overall demand in the power system and is expected to remain prior to 2030.



NOTE: EVs assumed only light passenger vehicles for now.
Sources: Calitz (2018); Bedir, N. et. Al. (2018); U.S. Department of Energy (2014); EPRI (2007)

Figure 29: Typical e-vehicle charging profiles and impact on the electrical demand profile

In this analysis, the e-vehicle fleet is modelled similarly to the EWH demand shaping resource. It also has intra-day controllability (can be dispatched as needed on any given day) based on power system needs but needs to have a net-zero energy balance on a daily basis (no substitution effect). It was assumed that e-vehicles have Vehicle-to-Grid (V2G) capability from 2031 onwards and the impact of e-vehicle charging prior to 2030 is inherent in the demand forecast. Using key input parameters and assumptions on the likely e-vehicle fleet by 2050, the potential demand flexibility via e-vehicles is calculated. Key input parameters include current population, expected population growth to 2050, current number of motor vehicles, expected motor vehicles per capita by 2050, adoption rate of e-vehicles by 2050, e-vehicle capacity (MW), e-vehicle energy requirement (GWh/d) and proportion of the e-vehicle fleet connected simultaneously. The calculations performed to estimate the likely e-vehicle fleet and key properties used in modelling the fleet for demand side flexibility is summarised in Table 3.

Table 3: Input parameters and calculations for demand side flexibility from e-vehicles over the time horizon 2016-2050

Property	Unit	2016-2019	2020	2031	2040	2050
Population	[mln]	0 - 0	58.0	61.7	64.9	68.2
Number of motor vehicles	[mln]	7 - 8.2	8.5	12.3	16.2	20.5
EVs adoption	[%]	0 - 0	1.5	8.1	28.5	48.9
Number of EVs	[mln]	0 - 0	0.1	1.0	4.6	10.0
EVs energy requirement	[TWh/a]	-	0.5	3.7	17.1	37.0
EVs energy requirement	[GWh/d]	-	1.3	10.1	46.8	101.4
EVs (demand increase)	[MW]	-	-	4 600	44 300	95 800
EVs (demand decrease)	[MW]	-	-	400	2 000	4 200

4.1.2.4 Outcomes

The results summary for the DSR scenario is shown in Figure 30. The DSR scenario results in no new coal or nuclear investment over the investment horizon (similar to IRP1). By 2030, the least-cost mix consists of new gas-fired capacity (flexibility), solar PV and wind investments. Import hydro is cost optimal between 2030 and 2040. By 2050, 18% of the energy mix is coal (all existing) complemented by gas (17%), hydro (9%), wind (40%) and solar PV (16%).

Figure 31 shows the difference in installed capacity and energy mix in the DSR scenario relative to IRP1. The impact of DSR relative to the IRP1 scenario is marginal with slightly less capacity being deployed by 2030, combined with a shift in the timing of import hydro between 2030 and 2040. There is no change in timing of the first new build capacity.

Figure 32 shows the CO_2 and water usage for the DSR scenario. It can be seen that there is only a marginal difference in CO_2 and water usage relative to the IRP1 scenario due to the different timing/phasing of new investment. The same can be observed for the difference in total system cost shown in Figure 33.

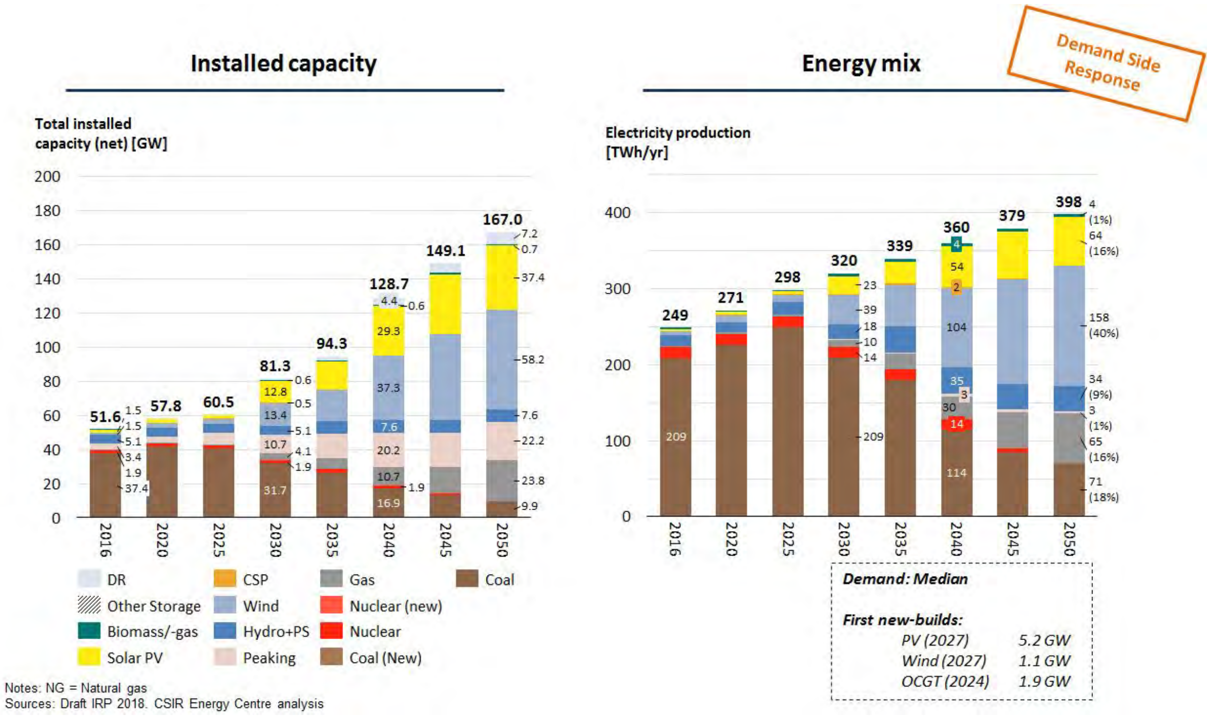


Figure 30: Installed capacity and energy mix for the DSR scenario

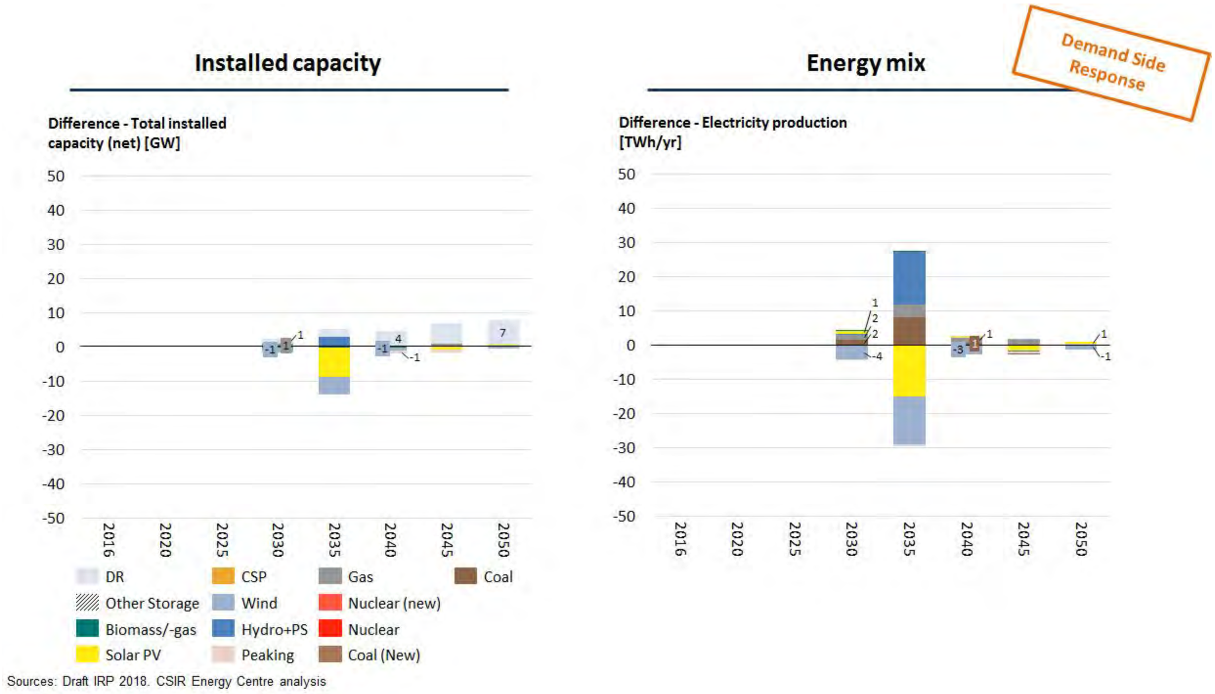


Figure 31: Difference in installed capacity and energy mix in the DSR scenario relative to IRP1

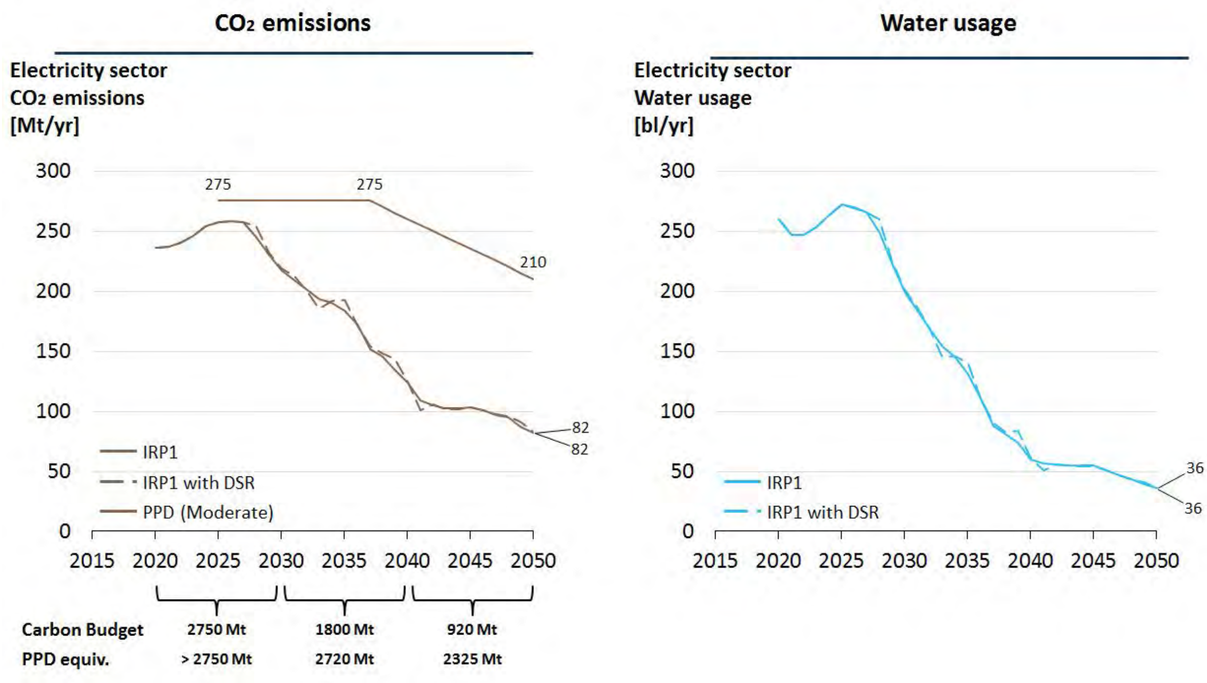


Figure 32: Emission and water trajectories for the IRP1 and DSR scenarios

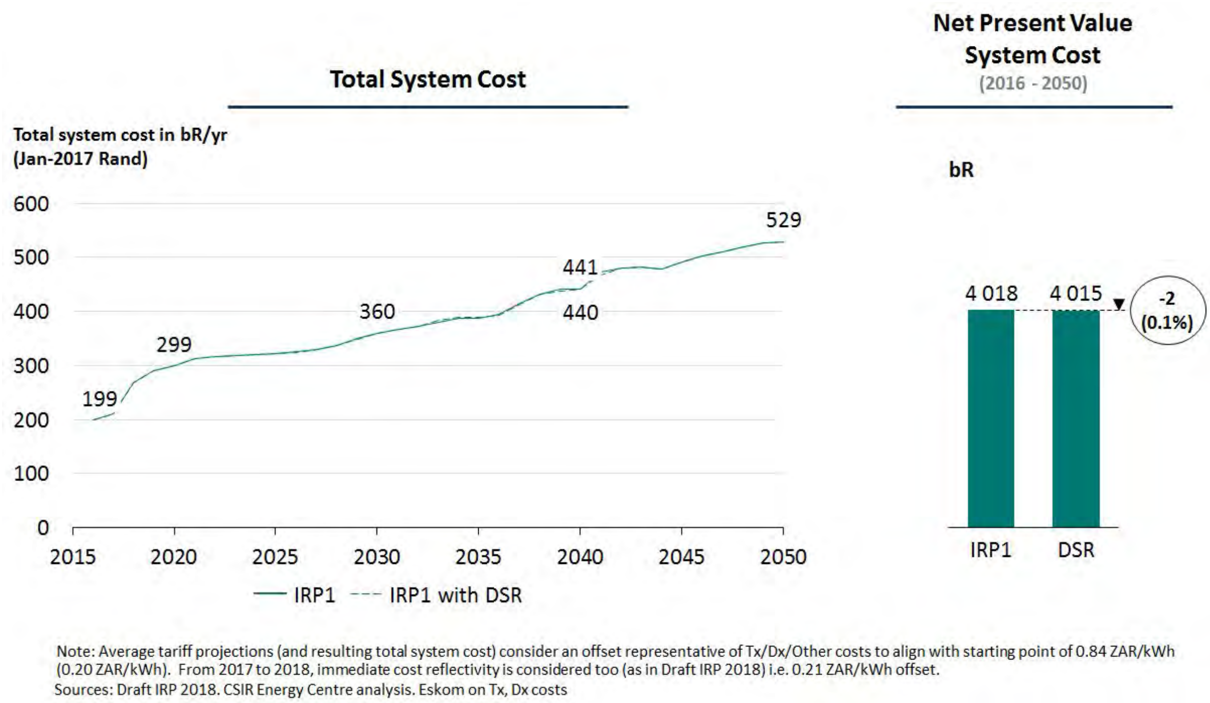


Figure 33: Total system costs for the IRP1 and DSR scenarios

4.1.3 Further technology learning (RE)

4.1.3.1 Scenario description

This scenario quantifies the impact of further learning rates for wind, solar PV and CSP relative to those assumed in the IRP1 scenario. Key differences between input assumptions for solar PV, wind and CSP in the Draft IRP 2016, Draft IRP 2018 and this scenario are highlighted in Figure34 - Figure 36 respectively. As can be seen, the Draft IRP 2018 assumes the starting point for solar PV and wind to be similar to levels achieved in the REIPPPP Bid Window (BW) 4 (Expedited) while CSP is at the latest REIPPPP BW equivalent tariff achieved. These are followed by a moderate level of further learning by 2030 (≈20% for solar PV, ≈10% for wind) following which costs remain constant.

The cost assumptions for this scenario similarly assume that solar PV, wind and CSP start at the most recently achieved REIPPPP BW 4 (Expedited) levels in 2016. From this, solar PV has further cost reductions of ≈66% by 2040, remaining constant thereafter. Wind is assumed to have further cost reductions of ≈47% by 2040, remaining constant thereafter. CSP is assumed to follow a similar learning curve shape to that of the IRP 2010-2030 until 2030 following which costs remain constant.

The further technology learning scenario is defined by the following input assumptions:

- *Demand forecast:*	Median (IRP 2018)
- *Supply technologies costs:*	IRP 2018 with reductions in PV, wind, CSP
- *Supply technologies new-build limits:*	None
- *DSR:*	None
- CO_2 *emissions trajectory:*	PPD (Moderate)
- *Existing fleet performance:*	IRP 2018 (Moderate)
- *Existing fleet decommissioning:*	IRP 2018
- *System adequacy (reserves):*	Eskom (to 2022), assumed thereafter

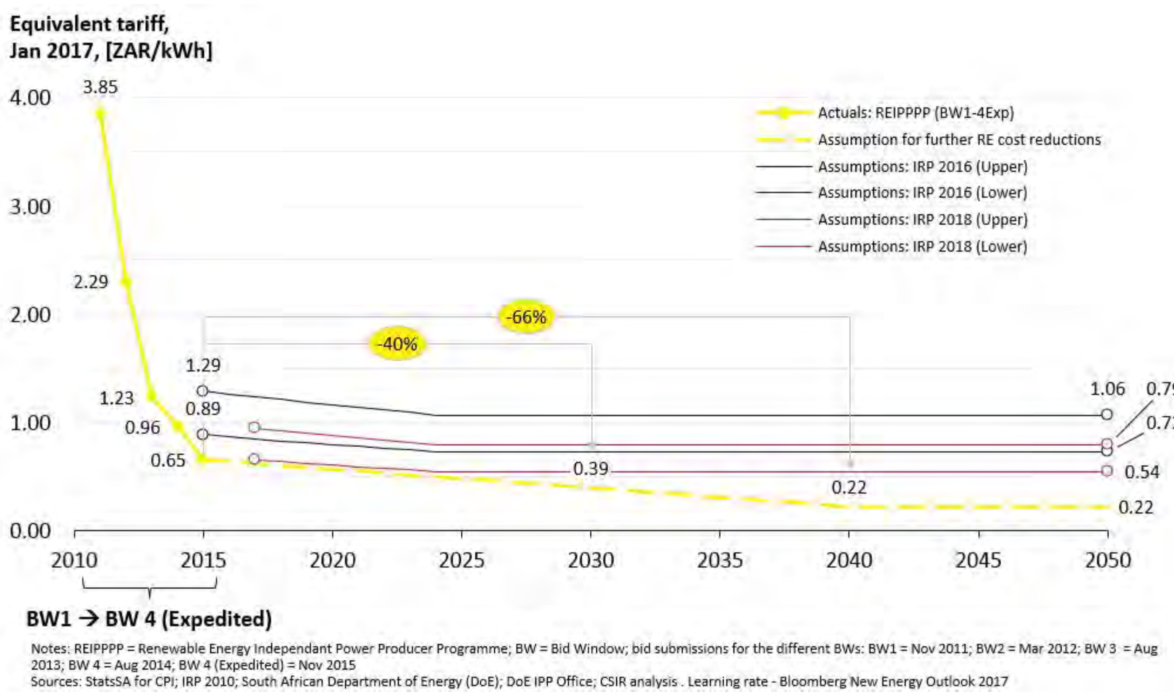


Figure 34: Equivalent cost assumption for solar PV based on fundamental cost structure of the technology (Draft IRP 2016, Draft IRP 2018 and cost assumption for this scenario)

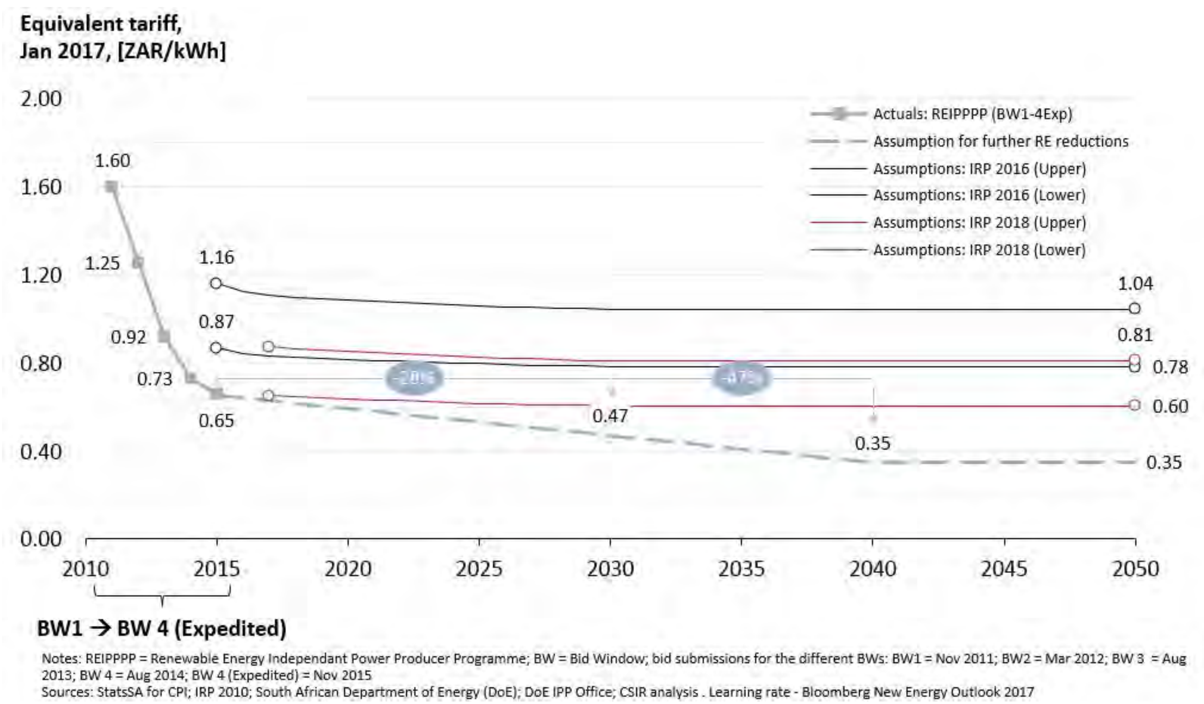


Figure 35: Equivalent cost assumption for wind based on fundamental cost structure of the technology (Draft IRP 2016, Draft IRP 2018 and cost assumption for this scenario)

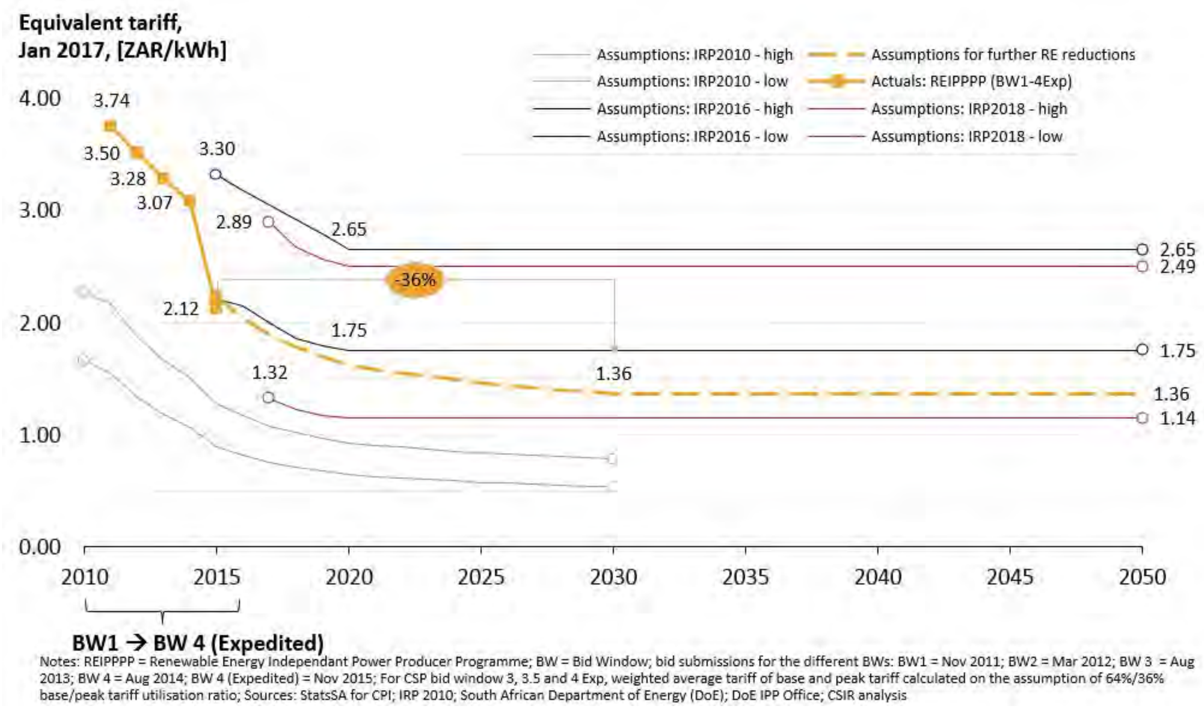


Figure 36: Equivalent cost assumption for CSP based on fundamental cost structure of the technology (Draft IRP 2016, Draft IRP 2018 and cost assumption for this scenario)

4.1.3.2 Outcomes

The results summary for the further technology learning scenario are shown in Figure 37. The impact of higher cost reductions in wind, solar PV and CSP results in import hydro no longer being cost optimal during the study horizon. By 2030, the least-cost mix consists of a similar amount of new gas capacity, solar PV and wind investments. By 2050, 17% of the energy mix is coal (all existing) complemented by gas (14%), hydro (4%), wind (43%), solar PV (21%) and biomass/-gas making up the remainder.

Figure 38 shows the difference in installed capacity and energy mix in this scenario relative to IRP1. The impact of further cost declines on the IRP1 scenario is a larger share of solar PV and wind as well as more peaking gas capacity and lower deployment of CCGTs. By 2030, an additional 2 GW of solar PV and 1 GW of wind is deployed with a slight reduction in energy from coal and CCGTs relative to IRP1. There is no change in timing of the first new build capacity.

Figure 39 shows the CO_2 and water usage for the further technology learning scenario. It can be seen that there is an absolute reduction in CO_2 and water usage relative to the IRP1 scenario due to the higher uptake of wind and solar PV.

Figure 40 shows the total system cost of the further technology learning scenario. It can be seen that IRP1 with further declines in solar PV and wind costs results in a ≈R6 bn/year cost reduction by 2030 and ≈R42 bn/year cost reduction by 2050 relative to IRP1 due to the cheaper cost of wind and solar PV being deployed.

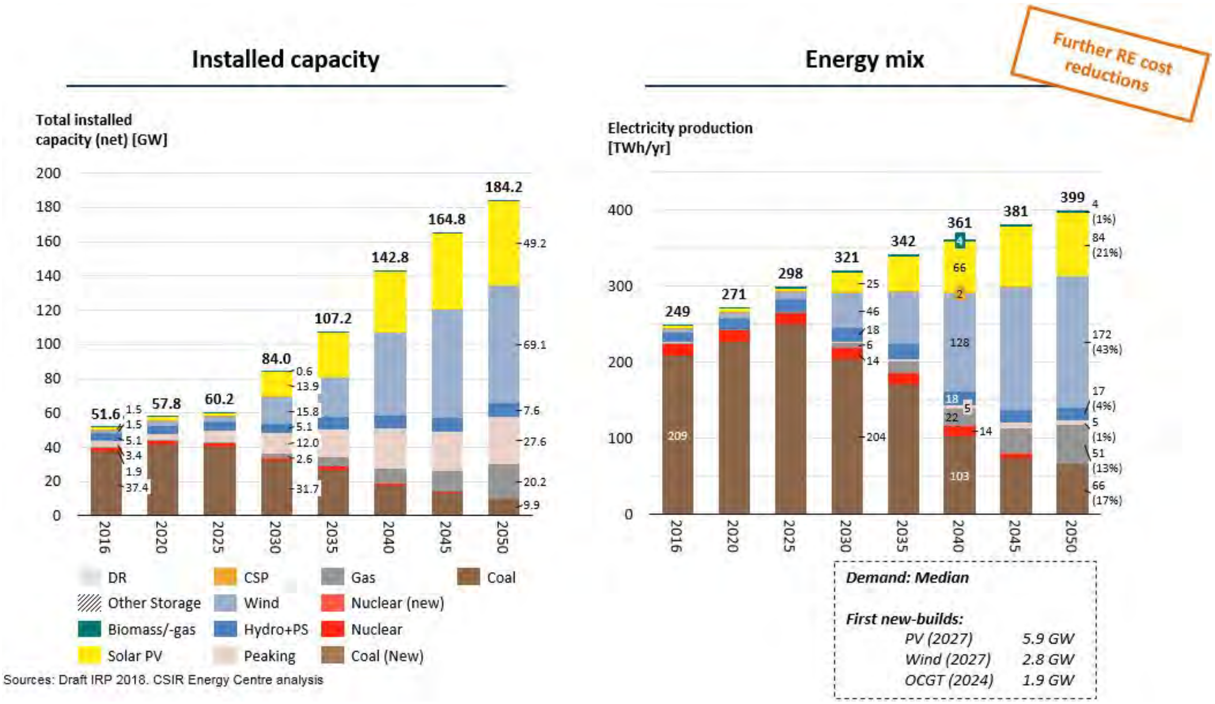
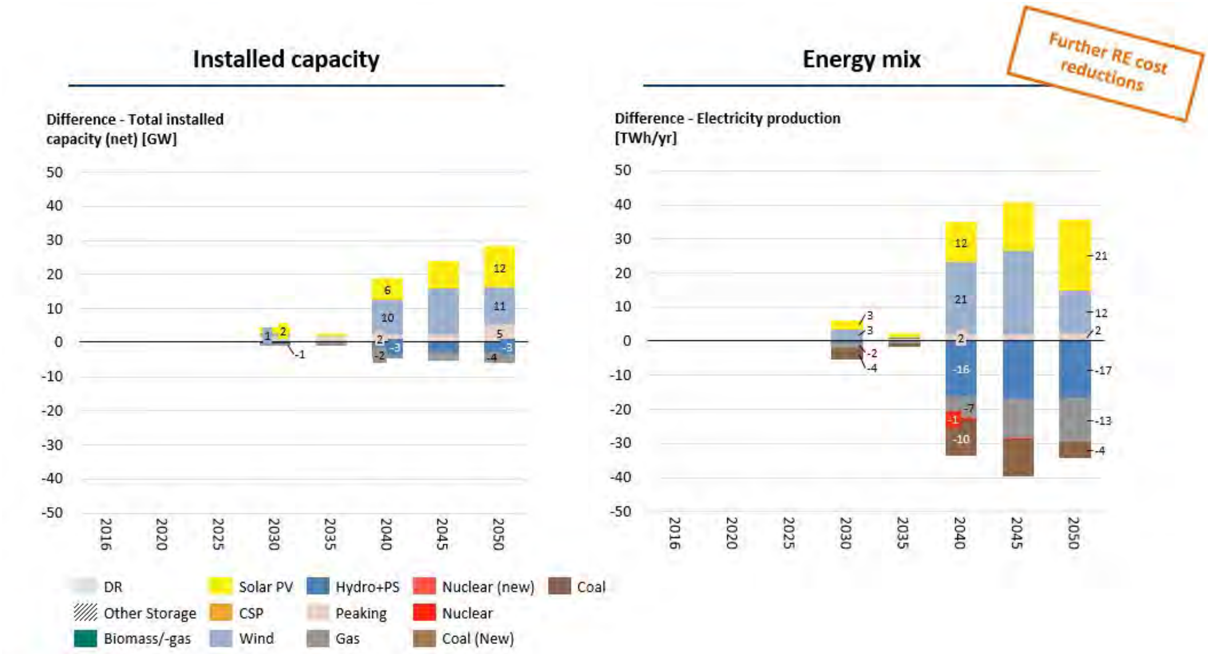


Figure 37: Installed capacity and energy mix for the further technology learning scenario



Sources: Draft IRP 2018. CSIR Energy Centre analysis

Figure 38: Difference in installed capacity and energy mix in the further technology learning scenario relative to IRP1

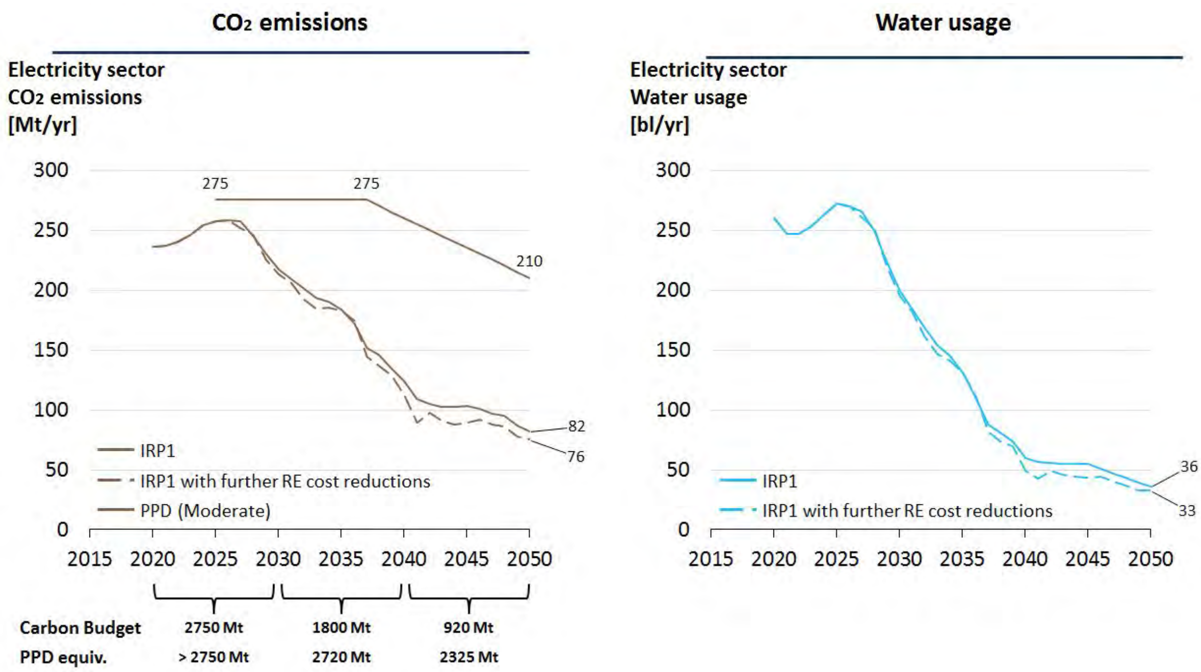


Figure 39: Emission and water trajectories for the IRP1 and further technology learning scenarios

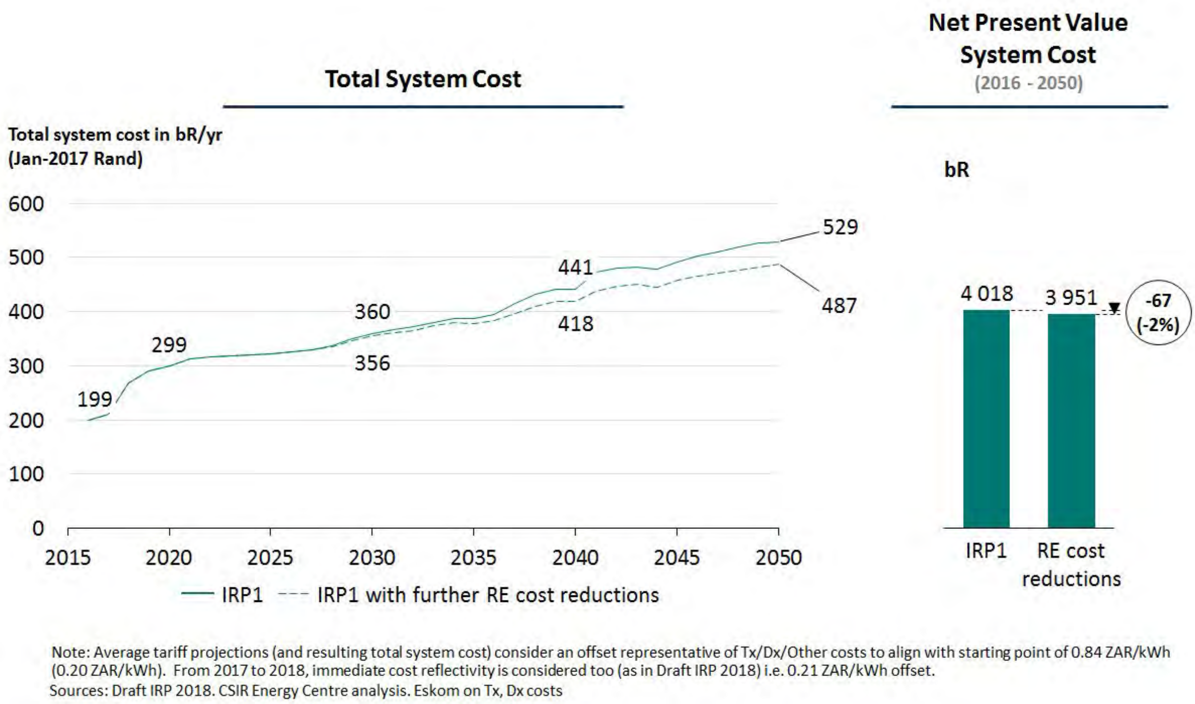


Figure 40: Total system costs for the IRP1 and further technology learning scenarios

4.1.4 A risk-adjusted scenario

4.1.4.1 Scenario description

A risk-adjusted scenario is considered which aims to quantify the impact of scenarios 4.1.1 (storage), section 4.1.2 (DSR) and section 4.1.3 (further VRE technology learning) simultaneously.

The risk-adjusted scenario is defined by the following input assumptions:

- *Demand forecast:*	Median (IRP 2018)
- *Supply technologies costs:*	IRP 2018 with reductions in storage, PV, wind, CSP
- *Supply technologies new-build limits:*	None
- *DSR:*	EWHs and e-vehicles
- CO_2 *emissions trajectory:*	PPD (Moderate)
- *Existing fleet performance:*	IRP 2018 (Moderate)
- *Existing fleet decommissioning:*	IRP 2018
- *System adequacy (reserves):*	Eskom (to 2022), assumed thereafter

4.1.4.2 Outcomes

The results summary for the risk-adjusted scenario is shown in Figure 41. This scenario results in no new coal or nuclear investment. Additionally, import hydro is no longer cost optimal during the study horizon. By 2030, the least-cost mix consists of new-build gas capacity, stationary storage, solar PV and wind investments. Stationary storage in the form of 1 hour and 3 hour storage capacity is deployed from 2027 onwards. By 2050, 17% of the energy mix is coal (all existing) complemented by gas (11%), hydro (4%), wind (40%), solar PV (27%) and biomass/-gas making up the remainder. There is no change in timing of the first new build capacity.

Figure 42 shows the difference in installed capacity and energy mix in the risk-adjusted scenario relative to IRP1. It can be seen that the combination of storage and RE technology cost declines along with DSR results in a larger share of renewable energy (with the RE share including more solar PV relative to wind when compared to IRP1) and a reduced deployment of gas-fired capacity. By 2030, an additional 5 GW of solar PV is deployed relative to IRP1 and an additional 26 GW of solar PV and 5 GW of wind is deployed by 2050. As expected, the energy share from gas and import hydro is significantly lower by 2050 relative to IRP1.

Figure 43 shows the CO_2 and water usage for the risk-adjusted scenario. It can be seen that there is an absolute reduction in CO_2 and water usage relative to the IRP1 scenario due to the higher uptake of wind and solar PV.

Figure 44 shows the total system cost of the risk-adjusted scenario. It can be seen that the total system cost is ≈R6 bn/year less by 2030 and ≈R52 bn/year less by 2050 relative to IRP1.

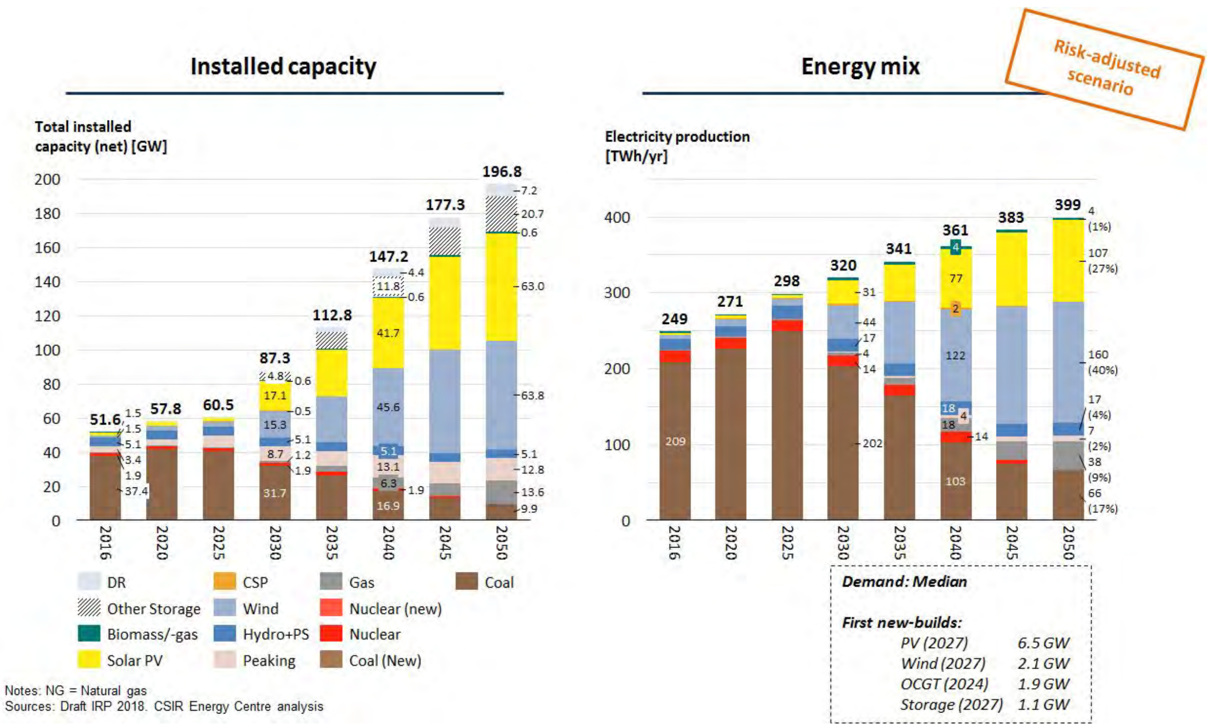


Figure 41: Installed capacity and energy mix for the risk-adjusted scenario

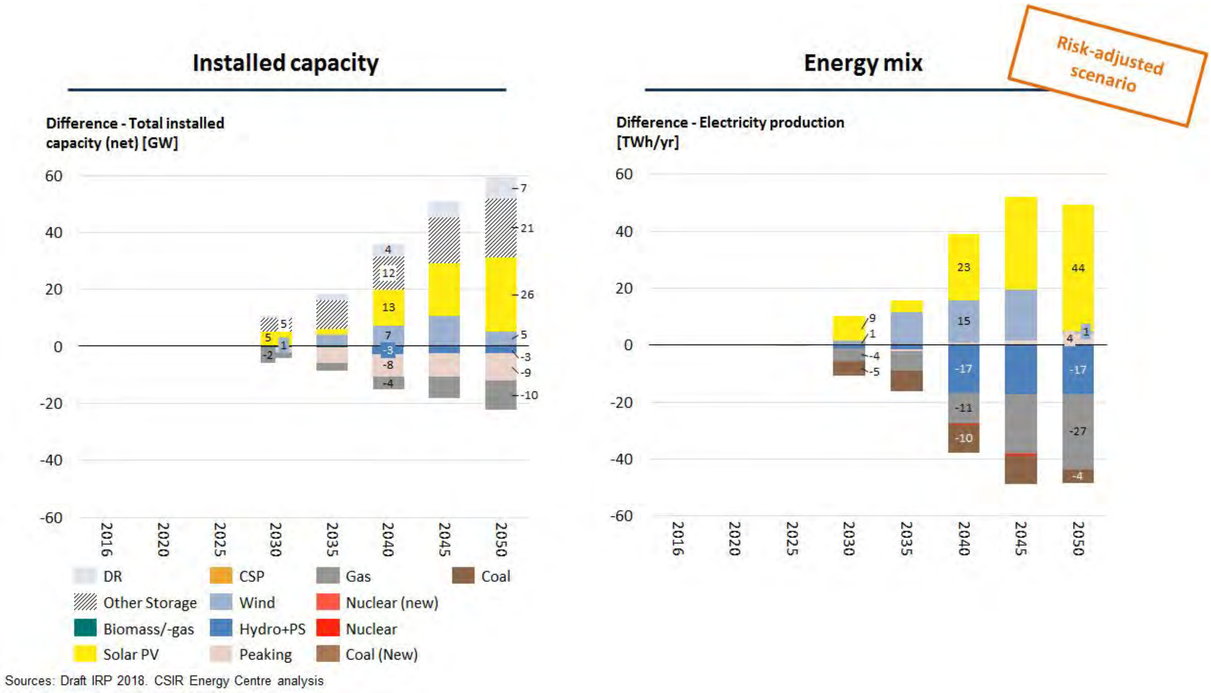


Figure 42: Difference in installed capacity and energy mix in the risk-adjusted scenario relative to IRP1

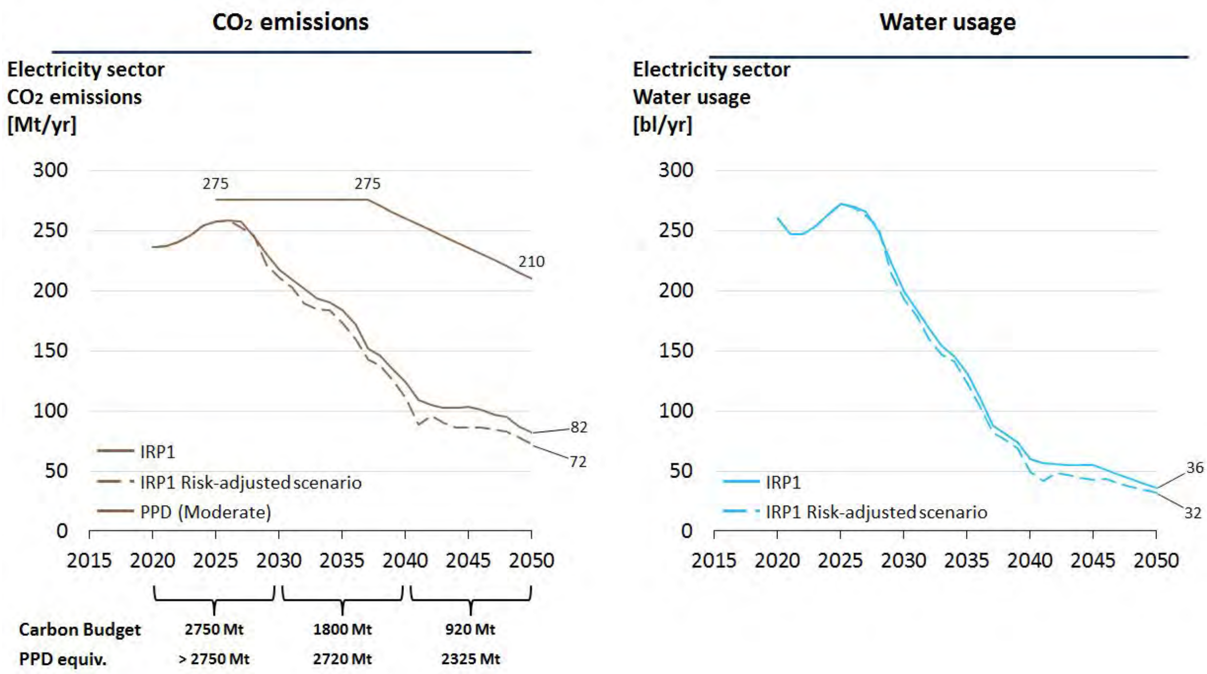


Figure 43: Emission and water trajectories for the IRP1 and risk-adjusted scenarios

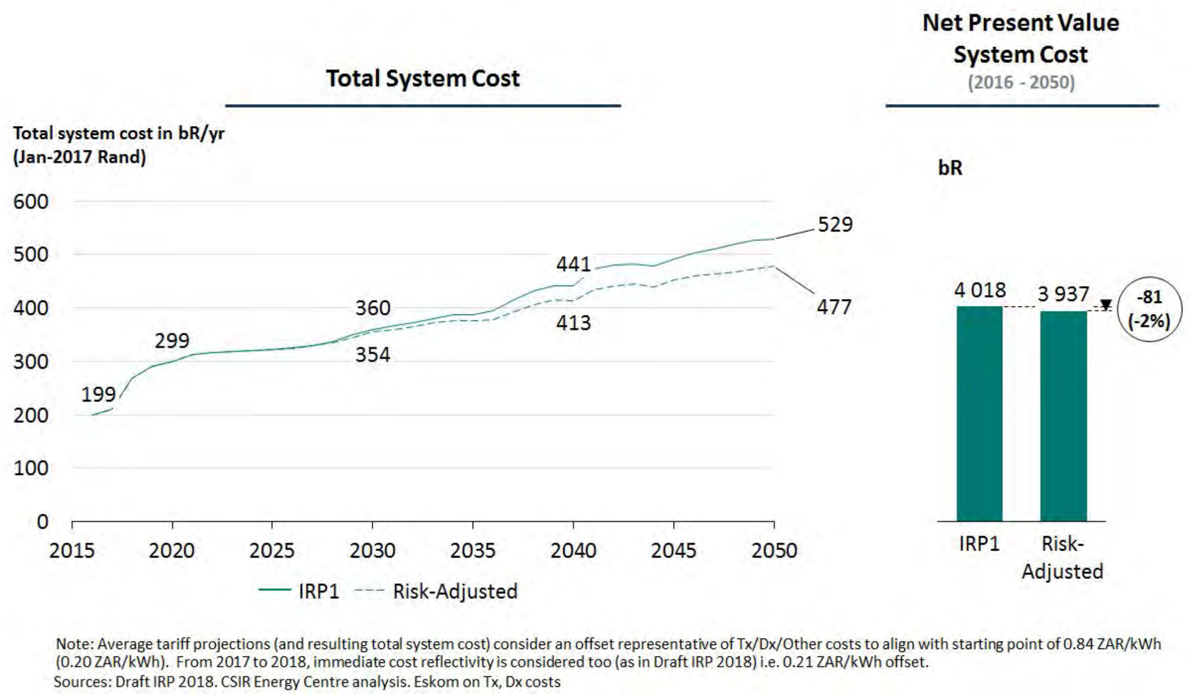


Figure 44: Total system costs for the IRP1 and risk-adjusted scenarios

Typical plots of weekly generation to meet demand for the IRP1 and risk-adjusted scenarios are shown in Figure 45 to Figure 50 for the same week in 2030, 2040 and 2050. The presence of stationary storage (in the form of batteries) and DSR dispatched in combination with wind and solar PV in the risk-adjusted scenario allows for a more consistent dispatch profile of the existing coal fleet. There is some curtailment of wind and solar PV from 2030 onwards as the penetration levels of these VRE sources increase. This curtailed energy is fully costed in the analysis as the cost of investment in capacity is fully captured in the optimization decision (whether the energy is used or not) and thus the decision to build more wind and/or solar PV with some curtailment is made on a purely economic basis.

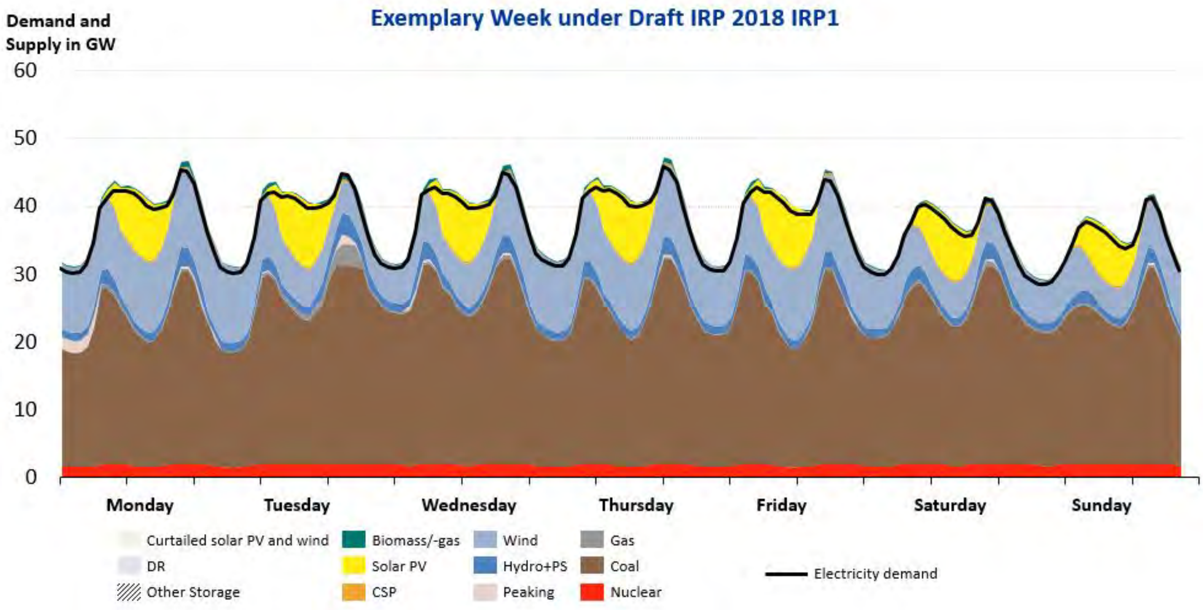


Figure 45: IRP1 simulated hourly total generation and demand for an exemplary week in 2030

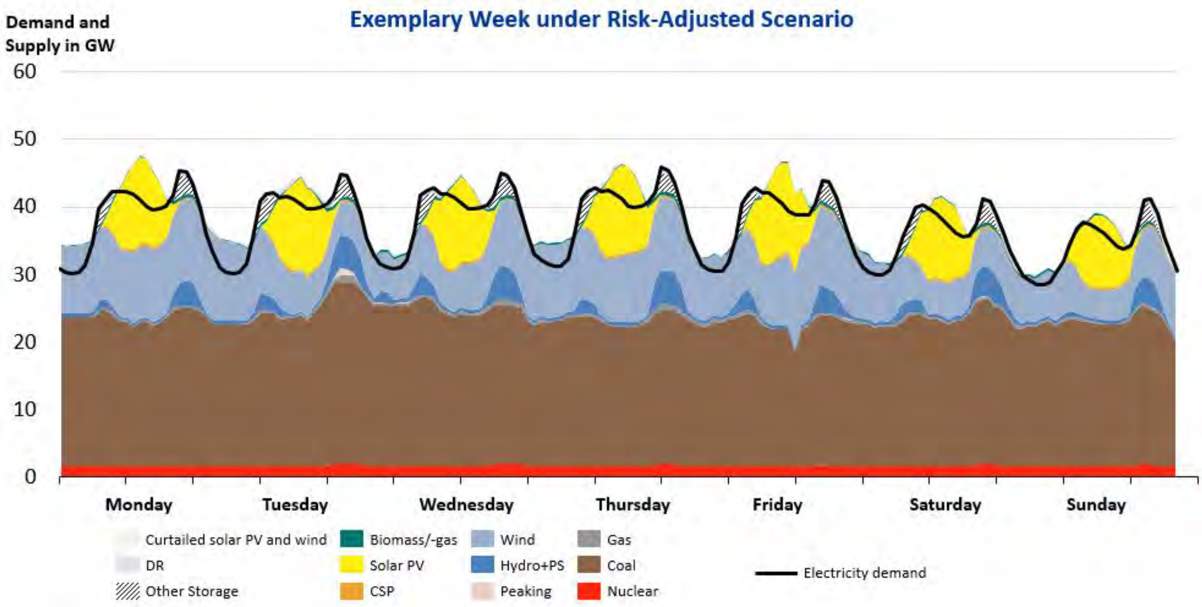


Figure 46: Risk-adjusted simulated hourly total generation and demand for an exemplary week in 2030

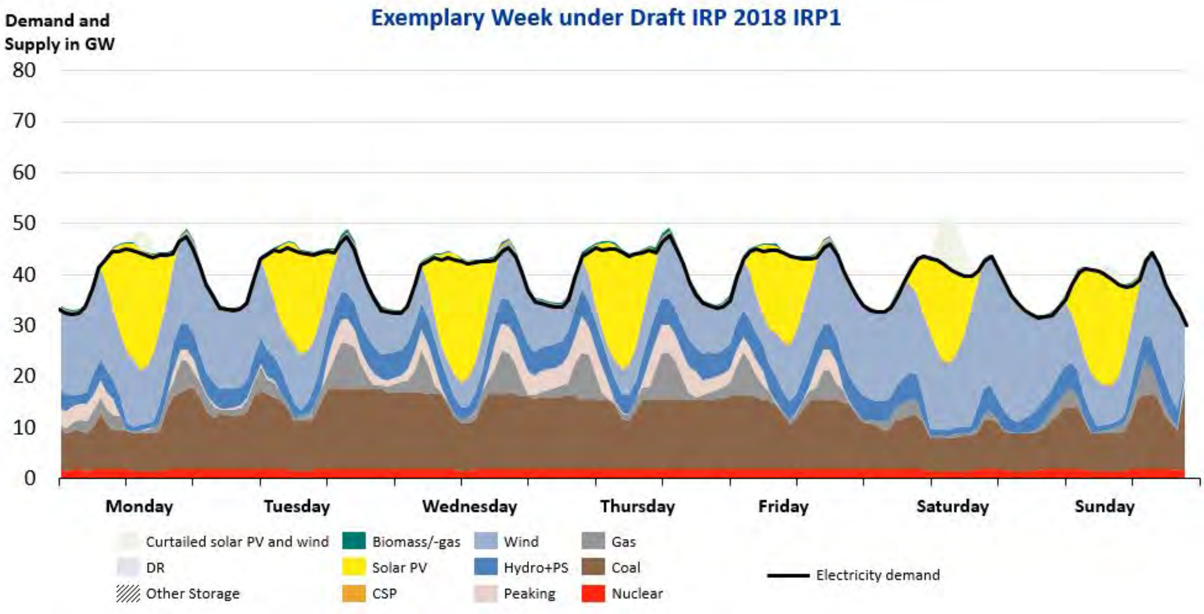


Figure 47: IRP1 simulated hourly total generation and demand for an exemplary week in 2040

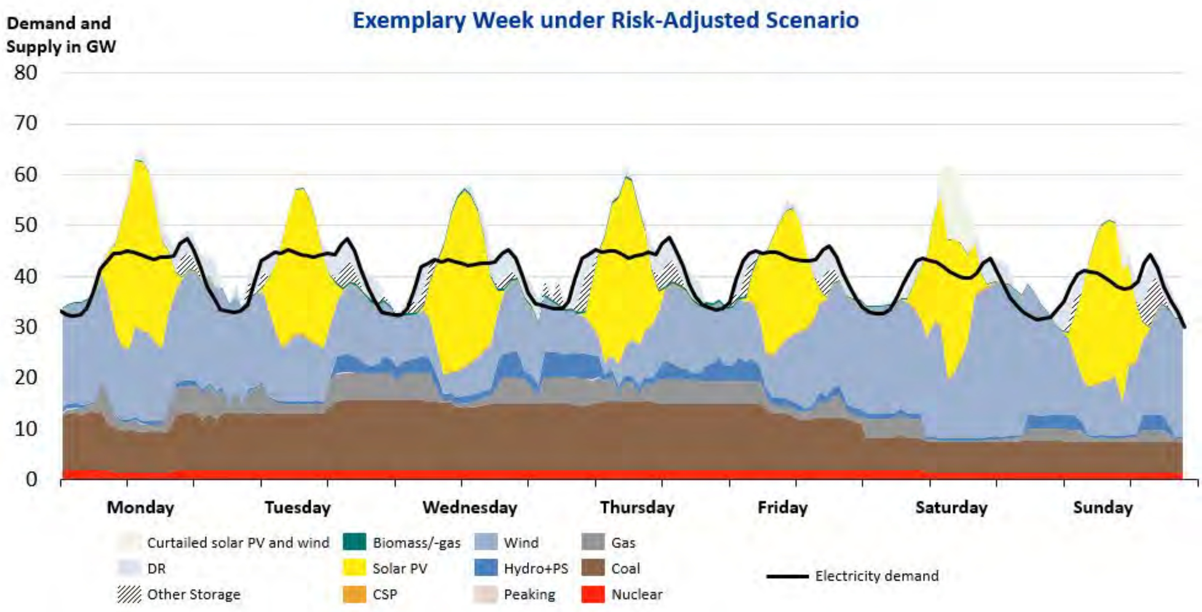


Figure 48: Risk-adjusted simulated hourly total generation and demand for an exemplary week in 2040

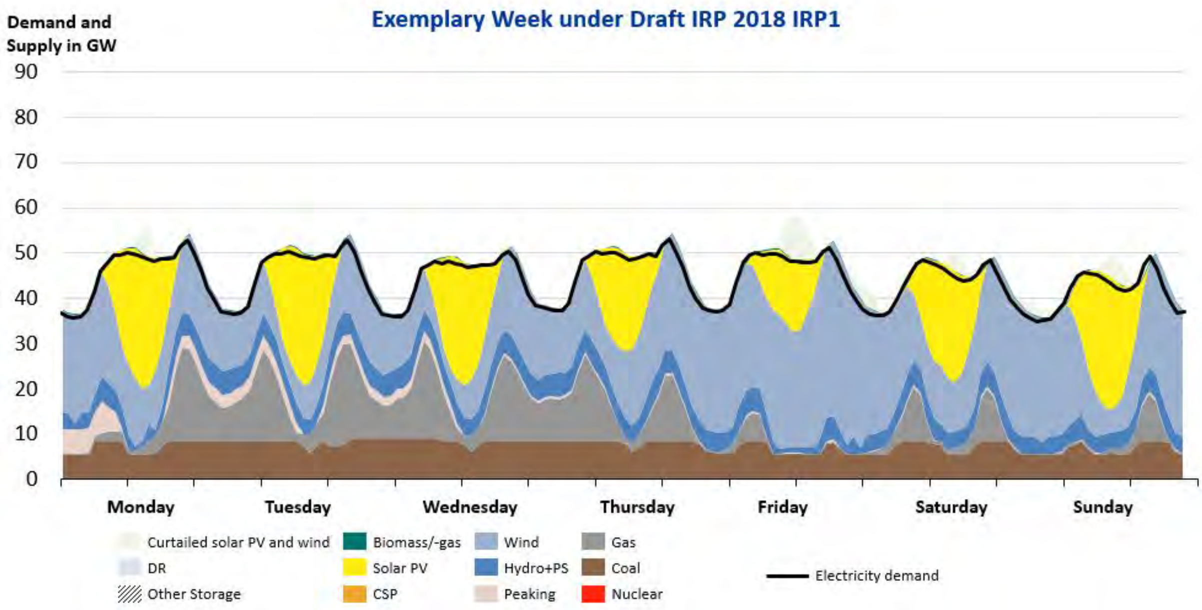


Figure 49: IRP1 simulated hourly total generation and demand for an exemplary week in 2050

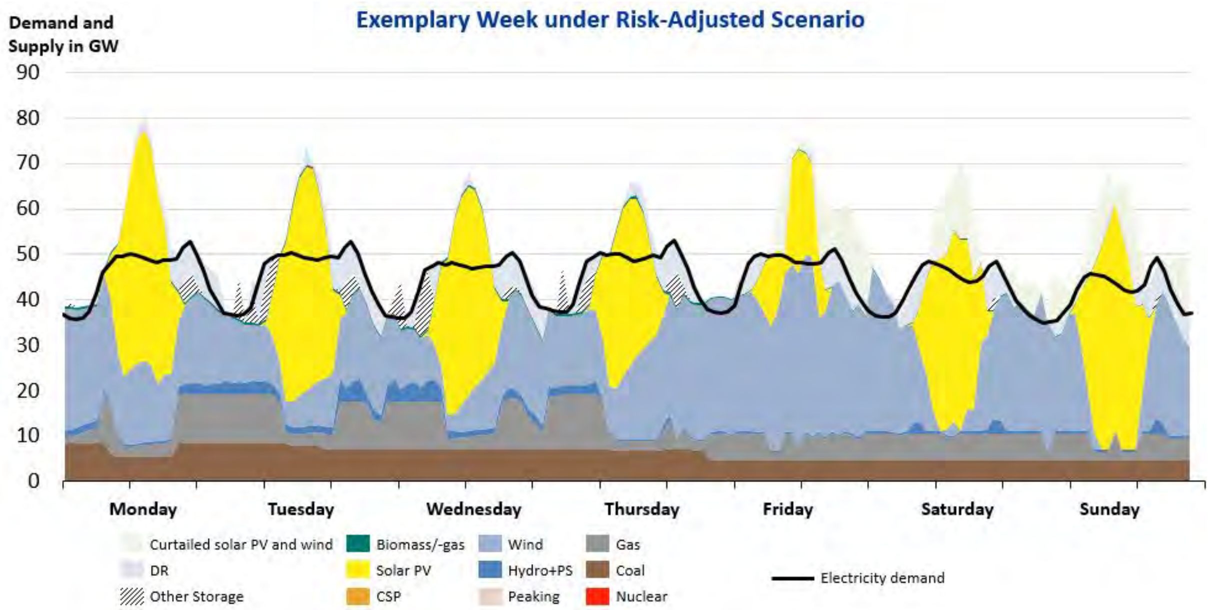


Figure 50: Risk-adjusted simulated hourly total generation and demand for an exemplary week in 2050

4.1.5 Existing coal fleet performance (Low EAF)

4.1.5.1 Scenario description

The existing fleet of power generators in South Africa is predominantly made up of the Eskom coal fleet. The Draft IRP 2018 considers the reliability of this fleet via the Energy Availability Factor (EAF) and expects EAF to follow the Moderate path shown in Figure 51. In this Moderate path, the fleet performance improves from the current ≈72% to 80% by 2021 and remains there until just after 2040 where slightly higher performance is assumed towards 82% (dominated by Medupi and Kusile).

This scenario attempts to demonstrate the impact on the IRP1 scenario of assuming the "Low" EAF path instead of the "Moderate" EAF.

This Low EAF scenario is defined by the following input assumptions:

- *Demand forecast:*	Median (IRP 2018)
- *Supply technologies costs:*	IRP 2018
- *Supply technologies new-build limits:*	None
- *DSR:*	None
- CO_2 *emissions trajectory:*	PPD (Moderate)
- *Existing fleet performance:*	IRP 2018 (Low)
- *Existing fleet decommissioning:*	IRP 2018
- *System adequacy (reserves):*	Eskom (to 2022), assumed thereafter

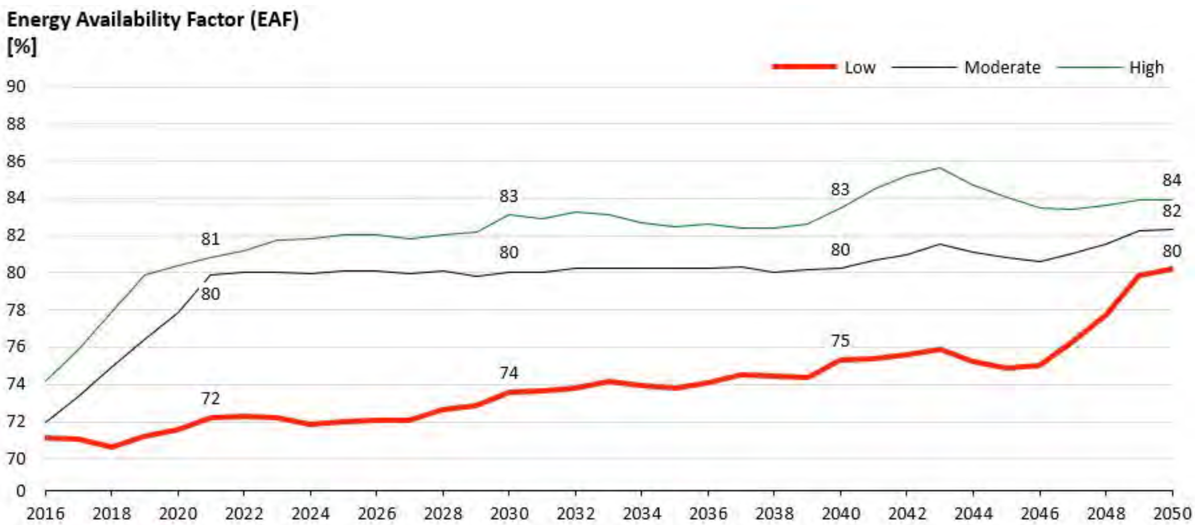


Figure 51: Energy Availability Factor (EAF) expectations of existing South African coal fleet

4.1.5.2 Outcomes

The results summary for the Low EAF scenario is shown in Figure 52. This scenario results in no new coal or nuclear investment. By 2030, the least-cost mix consists of new gas-fired capacity, solar PV and wind investments. By 2050, 18% of the energy mix is coal (all existing) complemented by gas (16%), hydro (8%), wind (43%), solar PV (14%) and biomass/-gas making up the remainder. An important observation in this scenario is the change in timing of the first new build solar PV and gas capacity to 2023, with wind being deployed from 2026 onwards.

Figure 53 shows the difference in installed capacity and energy mix in the Low EAF scenario relative to IRP1. The low EAF of the existing coal fleet results in a larger share of renewable energy and gas deployment by 2030 to cater for the reduced energy contribution of the existing coal fleet. By 2030, an additional 6 GW of solar PV, 2 GW of wind and 3 GW of CCGT capacity is deployed relative to IRP1. In 2050 the relative share of wind and peaking capacity increases with a slight reduction in solar PV and gas capacity relative to IRP1.

Figure 54 shows the CO_2 and water usage for the Low EAF scenario. It can be seen that there is an absolute reduction in CO_2 and water usage relative to the IRP1 scenario due to the unavailability of the existing coal fleet and increase in renewable energy generation.

Figure 55 shows the total system cost of the Low EAF scenario increases relative to IRP1 due to the additional capacity investment required to meet demand.

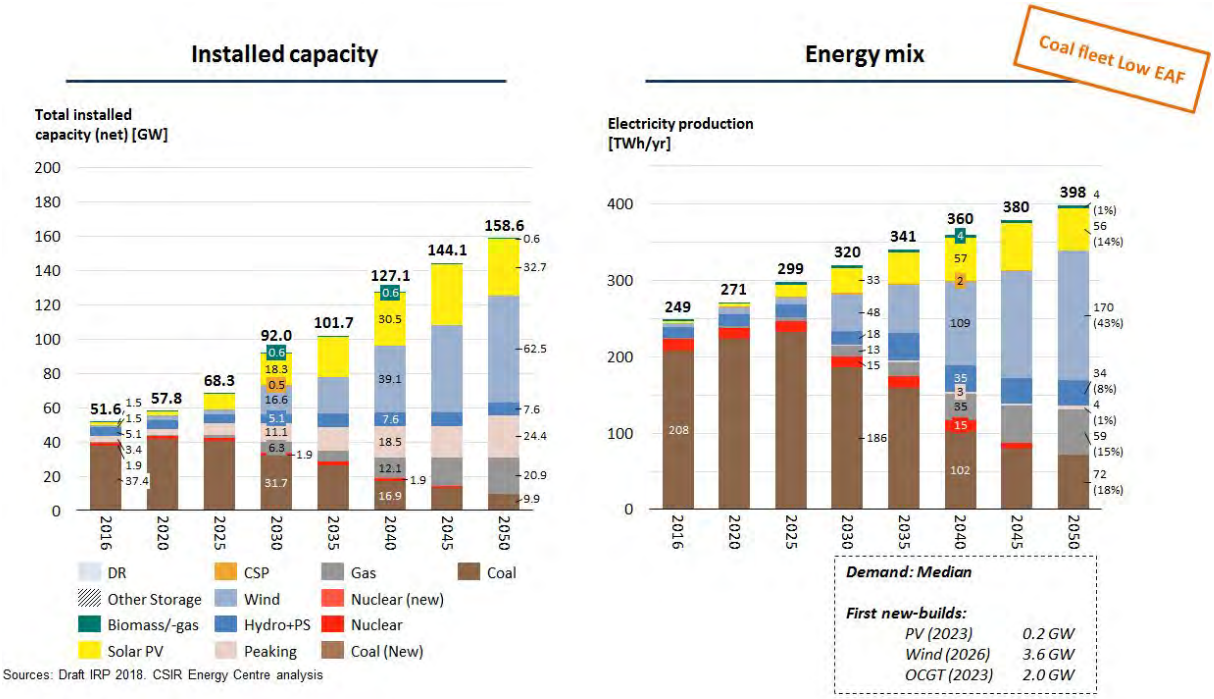


Figure 52: Installed capacity and energy mix for the Low EAF scenario

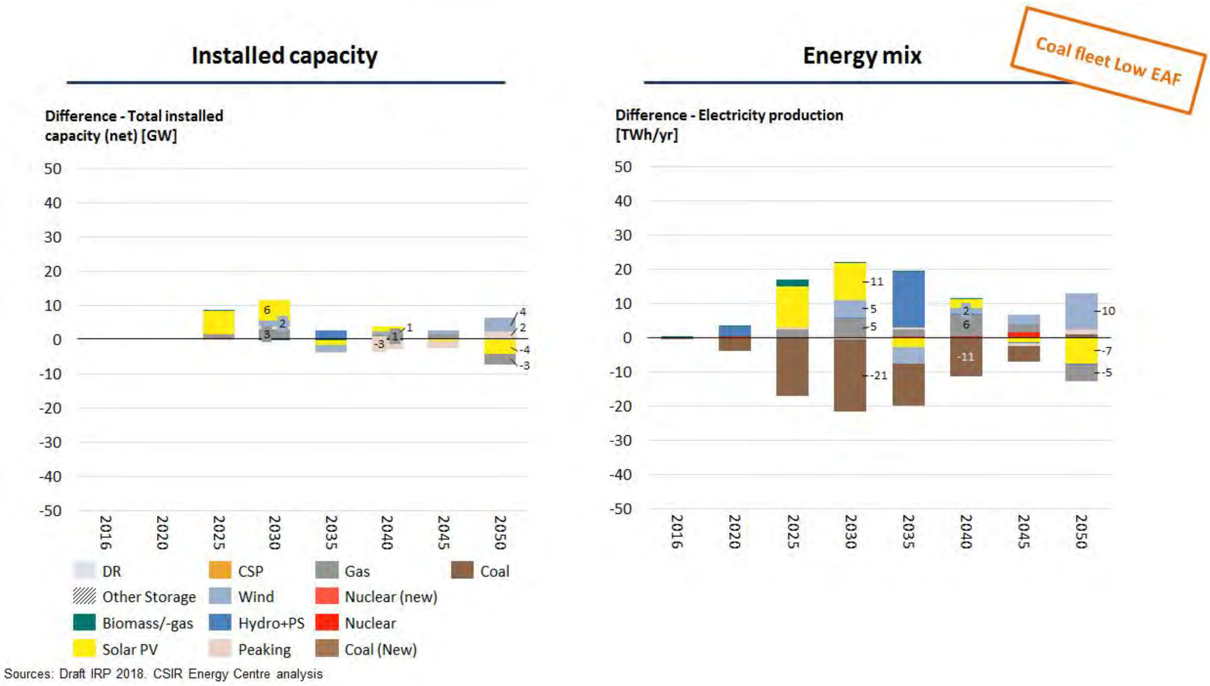


Figure 53: Difference in installed capacity and energy mix in the Low EAF scenario relative to IRP1

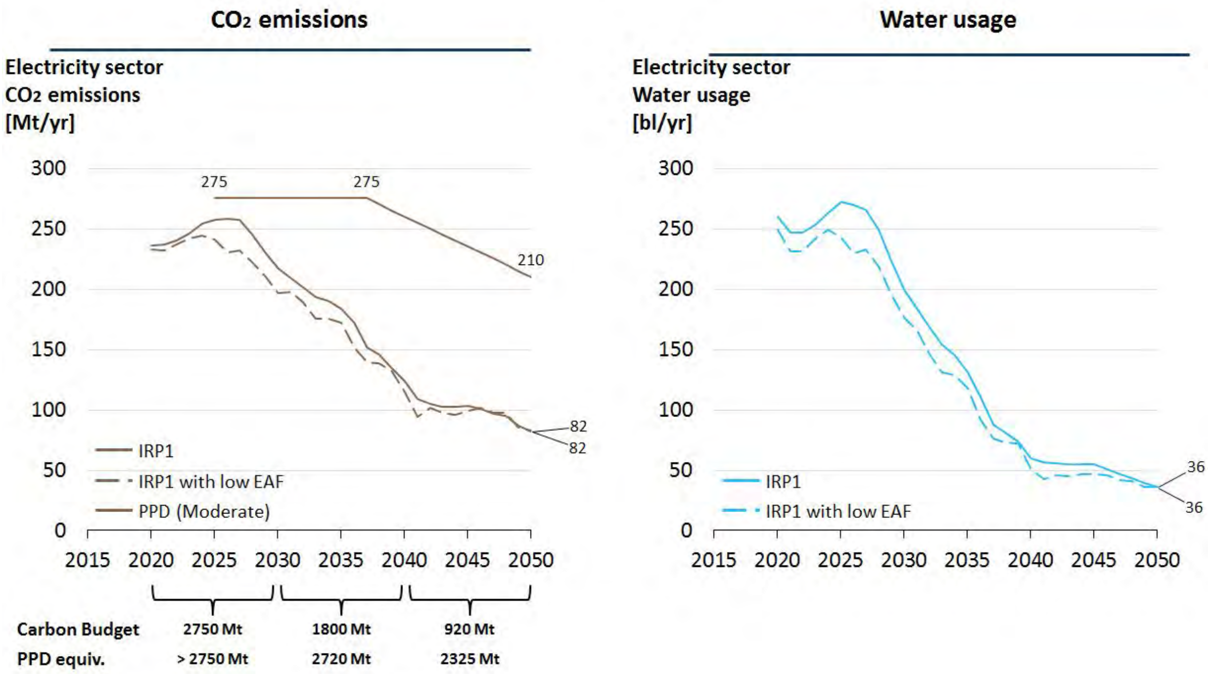


Figure 54: Emission and water trajectories for the IRP1 and Low EAF scenarios

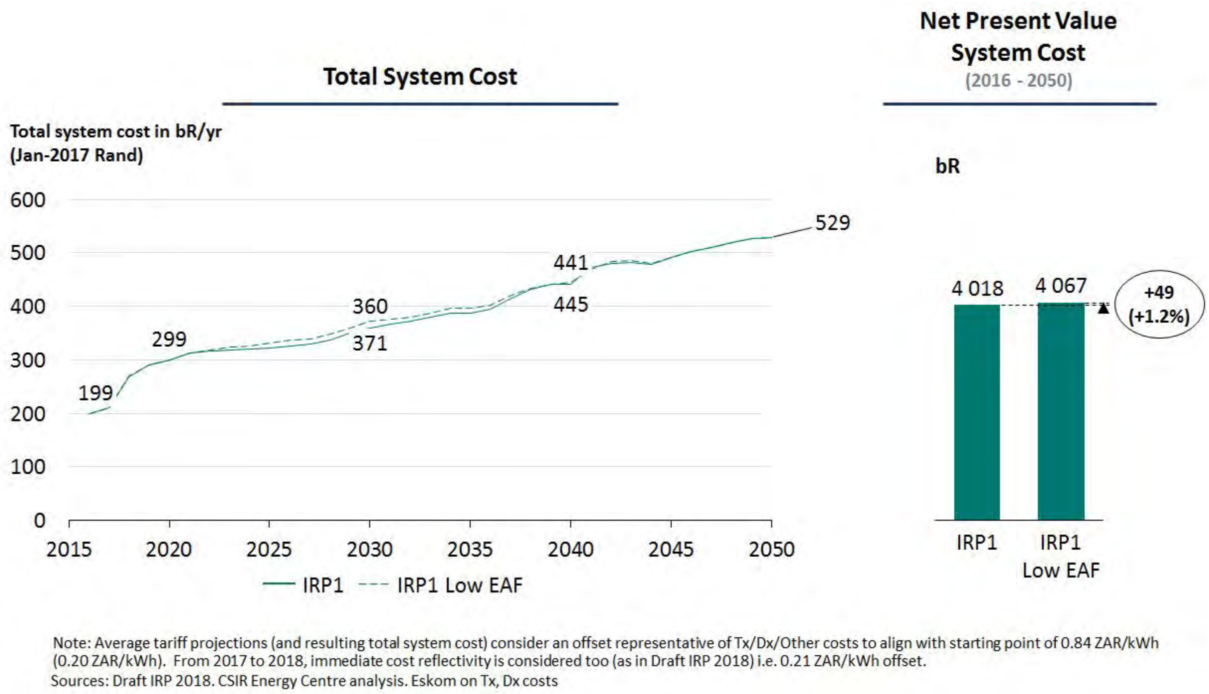


Figure 55: Total system costs for the IRP1 and Low EAF scenarios

4.1.6 A risk-adjusted scenario (with Low EAF of existing coal fleet)

4.1.6.1 Scenario description

This scenario quantified the effects of considering the risk-adjusted scenario explored in section 4.1.4 but with a low EAF of the existing coal fleet.

This risk-adjusted low EAF scenario is defined by the following input assumptions:

- *Demand forecast:*	Median (IRP 2018)
- *Supply technologies costs:*	IRP 2018 with reductions in storage, PV, wind, CSP
- *Supply technologies new-build limits:*	None
- *DSR:*	EWHs and e-vehicles
- CO_2 *emissions trajectory:*	PPD (Moderate)
- *Existing fleet performance:*	IRP 2018 (Low)
- *Existing fleet decommissioning:*	IRP 2018
- *System adequacy (reserves):*	Eskom (to 2022), assumed thereafter

4.1.6.2 Outcomes

The results summary for this risk-adjusted low EAF scenario is shown in Figure56. By 2030, the least-cost mix consists of new gas capacity, stationary storage, solar PV and wind investments. Solar PV, wind and OCGTs are deployed from 2023 onwards and stationary storage (1 hour and 3 hour storage capacity) is deployed from 2024 onwards. There is thus a significant shift in timing of new-build wind and solar PV capacity compared to the moderate EAF scenario. By 2050, 17% of the energy mix is coal (all existing) complemented by gas (10%), hydro (4%), wind (42%), solar PV (26%) and biomass/-gas making up the remainder.

Figure 57 shows the difference in installed capacity and energy mix in the risk-adjusted with low EAF scenario relative to IRP1. It can be seen that the combination of the low EAF, storage and RE technology cost declines along with DSR results in a larger share of renewable energy and reduced levels of deployment of gas capacity as well as gas usage. By 2030, an additional 8 GW of solar PV and 7 GW of wind is deployed relative to IRP1 and an additional 24 GW of solar PV and 9 GW of wind is deployed by 2050. Although the annual new-build limits imposed on wind and solar PV in some IRP 2018 scenarios do not significantly change the energy mix prior to 2030 in the Draft IRP 2018 scenarios, they would become binding (and overly restrictive) if a low EAF materializes along with further storage and RE technology cost declines. The energy share from gas and import hydro is significantly lower by 2050 relative to IRP1, with new-build import hydro not forming part of the least-cost mix.

Figure 58 shows the CO_2 and water usage for the Risk-Adjusted with low EAF scenario. It can be seen that there is an absolute reduction in CO_2 and water usage relative to the IRP1 scenario due to the higher uptake of wind and solar PV.

Figure 59 shows the total system cost of the risk-adjusted with low EAF scenario. It can be seen that the total system cost over the full horizon is slightly higher than the risk-adjusted scenario with a moderate EAF (as expected as more new-build capacity is necessary to fill the gap left by the lower EAF of the existing coal fleet).

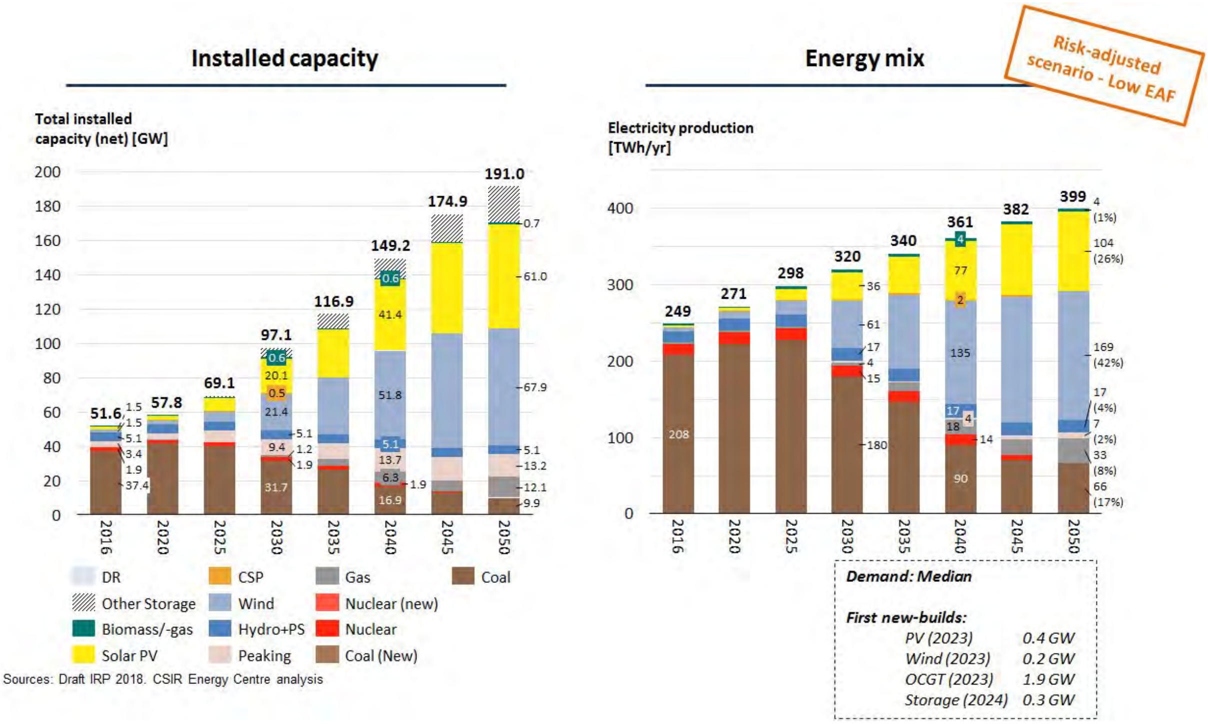


Figure 56: Installed capacity and energy mix for the risk adjusted low EAF scenario

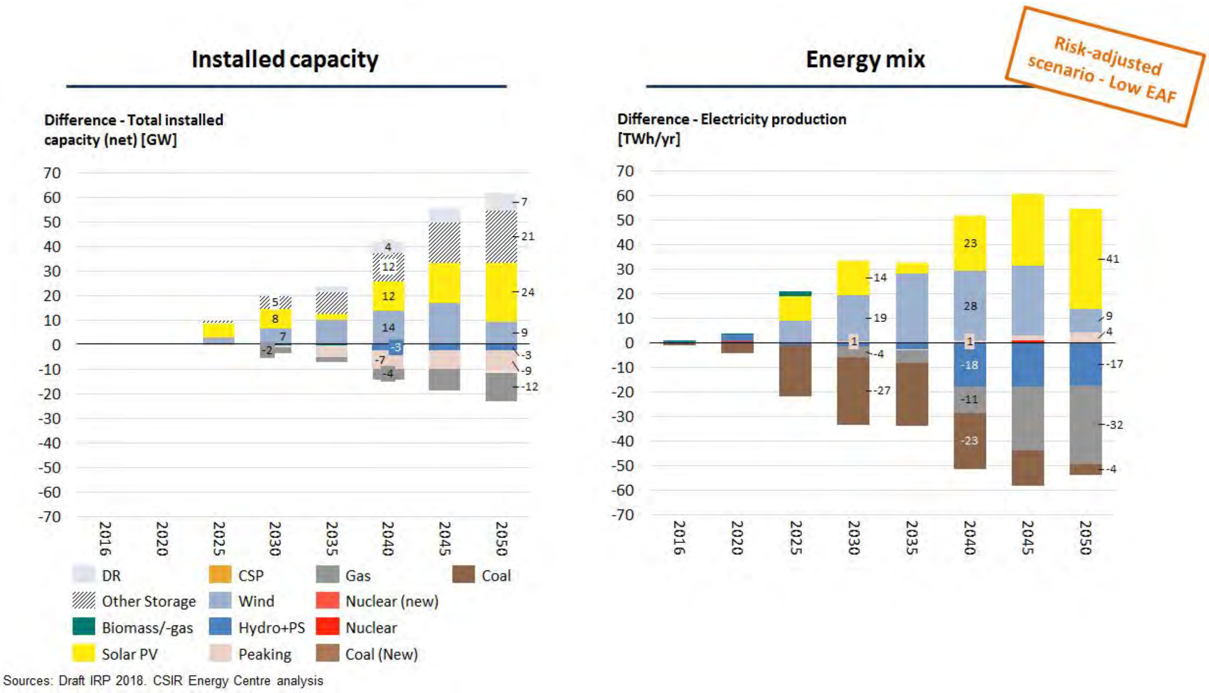


Figure 57: Difference in installed capacity and energy mix in the risk adjusted low EAF scenario relative to IRP1

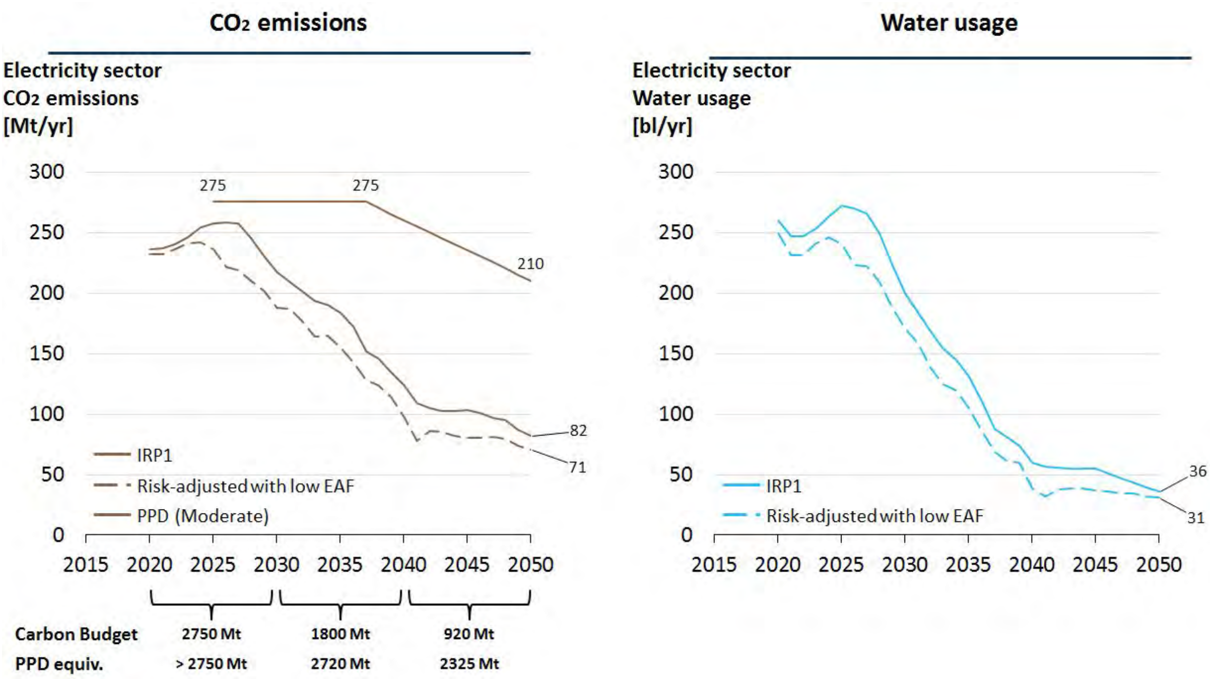
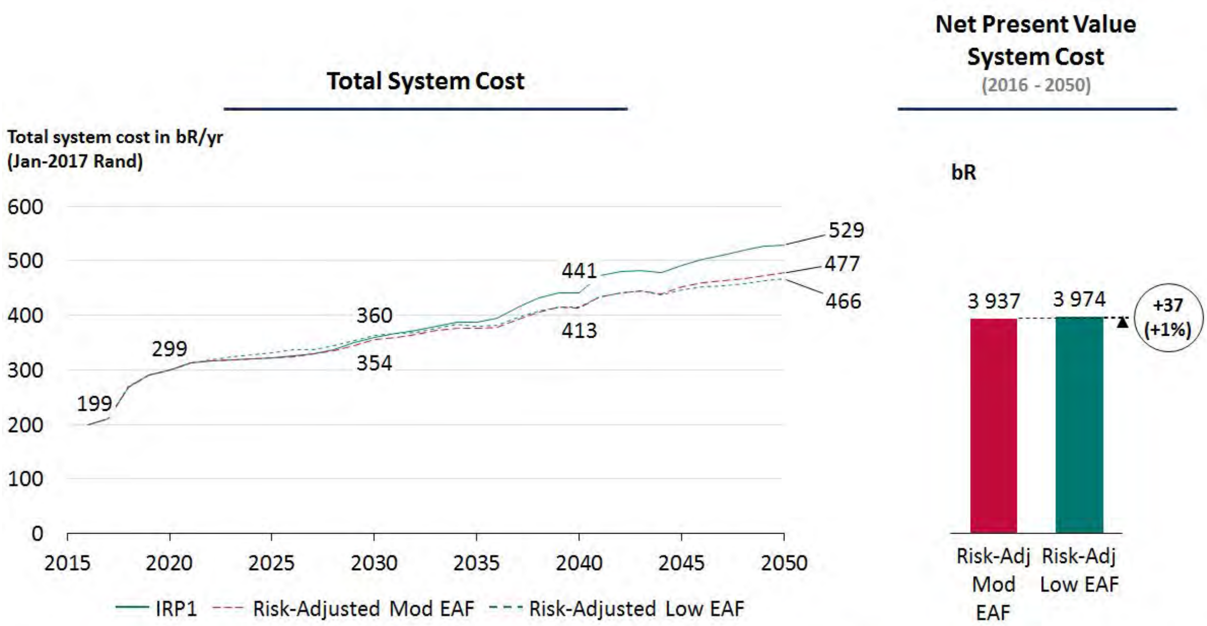


Figure 58: Emission and water trajectories for the IRP1 and risk adjusted low EAF scenarios



Note: Average tariff projections (and resulting total system cost) consider an offset representative of Tx/Dx/Other costs to align with starting point of 0.84 ZAR/kWh (0.20 ZAR/kWh). From 2017 to 2018, immediate cost reflectivity is considered too (as in Draft IRP 2018) i.e. 0.21 ZAR/kWh offset.
Sources: Draft IRP 2018. CSIR Energy Centre analysis. Eskom on Tx, Dx costs

Figure 59: Total system costs for the IRP1 and risk adjusted low EAF scenarios

4.2 Descriptive comments

4.2.1 Technology new-build limits

The new-build limits placed on solar PV and wind in the Draft IRP 2016 were retained in the Draft IRP 2018 as summarised in Figure 60 and 61 respectively. These are shown on an absolute and relative basis to show how the relative annual new-build limit actually decreases as the power system grows into the future.

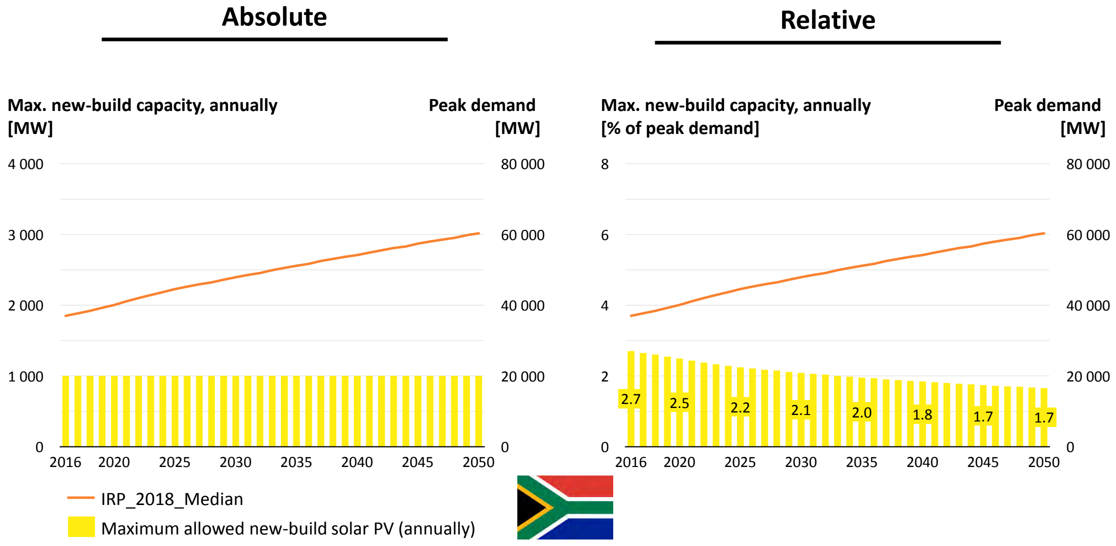
Thusfar, there has been no justification provided for these annual new-build limits. Some possible justifications could include:

- **Import infrastructure and transportation linkages**: Limitations surrounding the necessary capacity at ports and sufficient road/rail linkages to get equipment into the country and transport it to where it is planned to be installed;
- **Industry ability to deliver**: This would include the relevant domestic skills available, project development capabilities and/or construction capabilities;
- **Transmission & distribution network infrastructure:** The necessary available transmission and/or distribution networks to sufficiently evacuate power from the power generators to demand centres; and/or
- **System stability/security:** Concerns surrounding system security/stability and the know-how as well as operating procedures and philosophies to operate high penetration VRE power systems.

In Figure 62 and 63 respectively, historical annual new-build capacity deployed for solar PV and wind are shown for a number of jurisdictions globally highlighting leader and follower countries. What is also shown is the deployment of these technologies in South Africa in recent years (as part of the REIPPPP) overlaid with the new-build limits proposed in the Draft IRP 2018. From Figure 62 and 63 it is clear that there have been global deployment that far exceed the new-build limits imposed in the Draft IRP 2018.

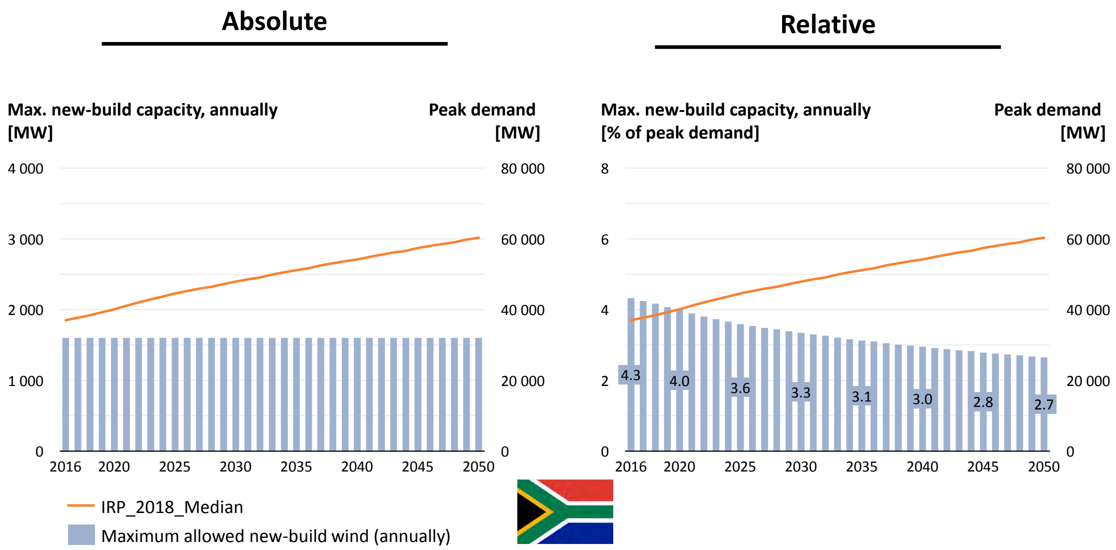
The cumulative effect of annual new-build deployment from Figure 62 and 63 is shown for solar PV and wind in Figure 64 and 65 respectively. From Figure 64, it is clear that solar PV penetration levels in leader countries was already in 2017 up to 1.3x that proposed as part of the constrained scenarios in the Draft IRP 2018 by 2050. Similarly, for wind, as shown in Figure 65, wind penetration levels of up to 1.4x that considered in the constrained scenarios of the Draft IRP 2018 were already in operation in 2017. it is also important to note that follower countries include developing countries like China, India and Brazil.

Solar PV is limited to 1000 MW annually resulting in a move from 2.5% of peak demand in 2020 to 1.7% of peak demand by 2050



114 Sources: Eskom; Draft IRP 2018; CSIR analysis

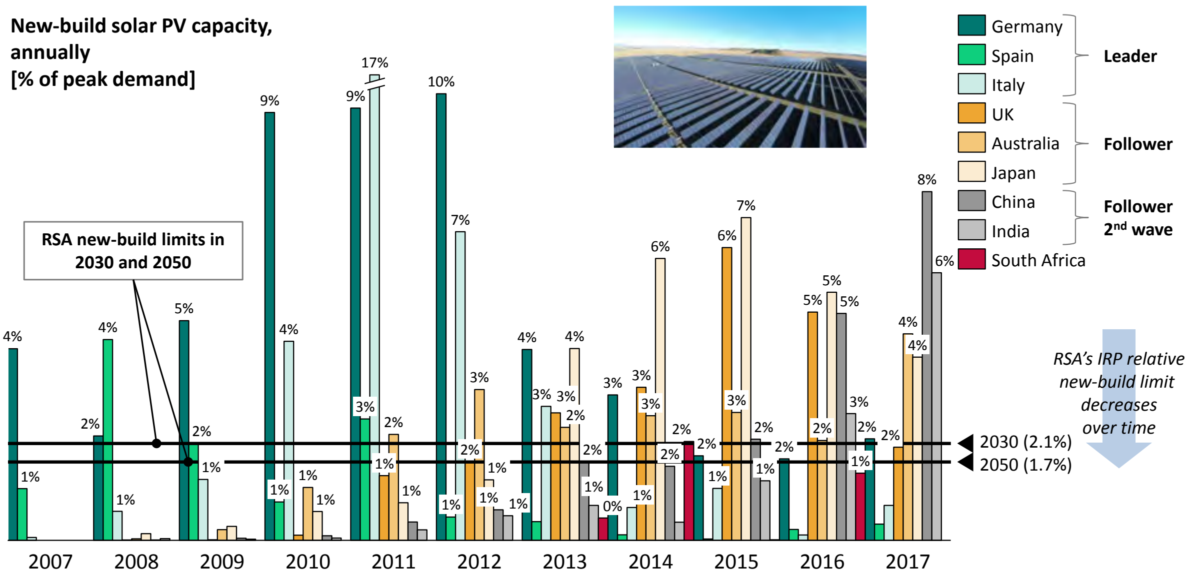
Wind is limited to 1600 MW annually resulting in a move from 4.0% of peak demand in 2020 to 2.7% of peak demand by 2050



115 Sources: Eskom; Draft IRP 2018; CSIR analysis

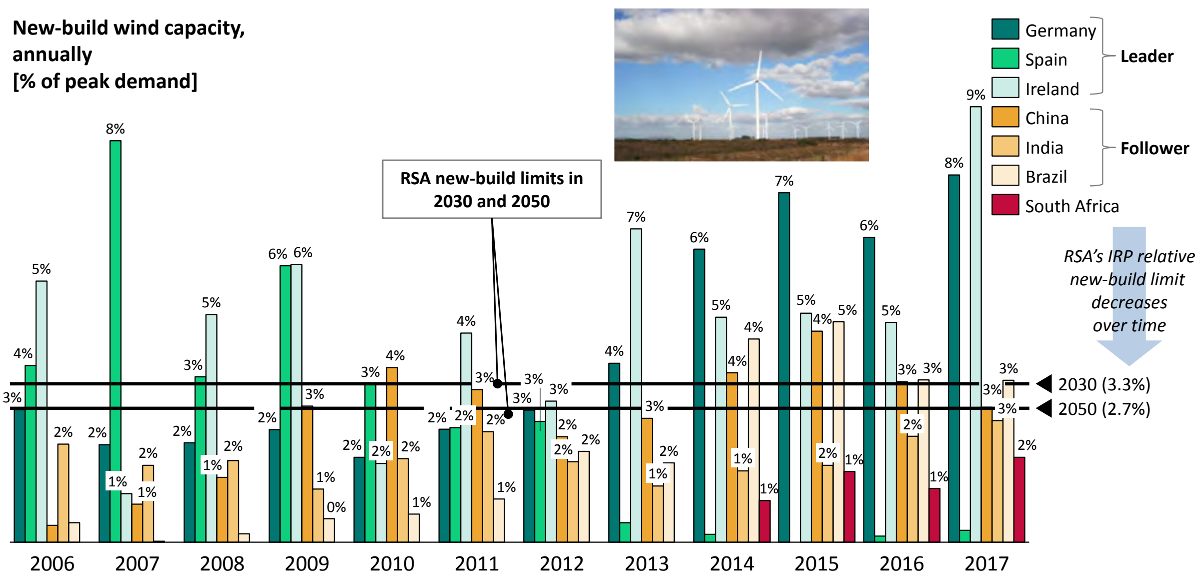
Figure 61: New-build limits imposed on wind (absolute and relative) across all Draft IRP 2018 scenarios (except IRP1)

Already happening: Both leader, follower and 2nd wave countries installing more new solar PV per year than South Africa's IRP limits for 2030/2050



116 Sources: SolarPowerEurope; CIGRE; websites of System Operators; IRP 2016 Draft; CSIR analysis

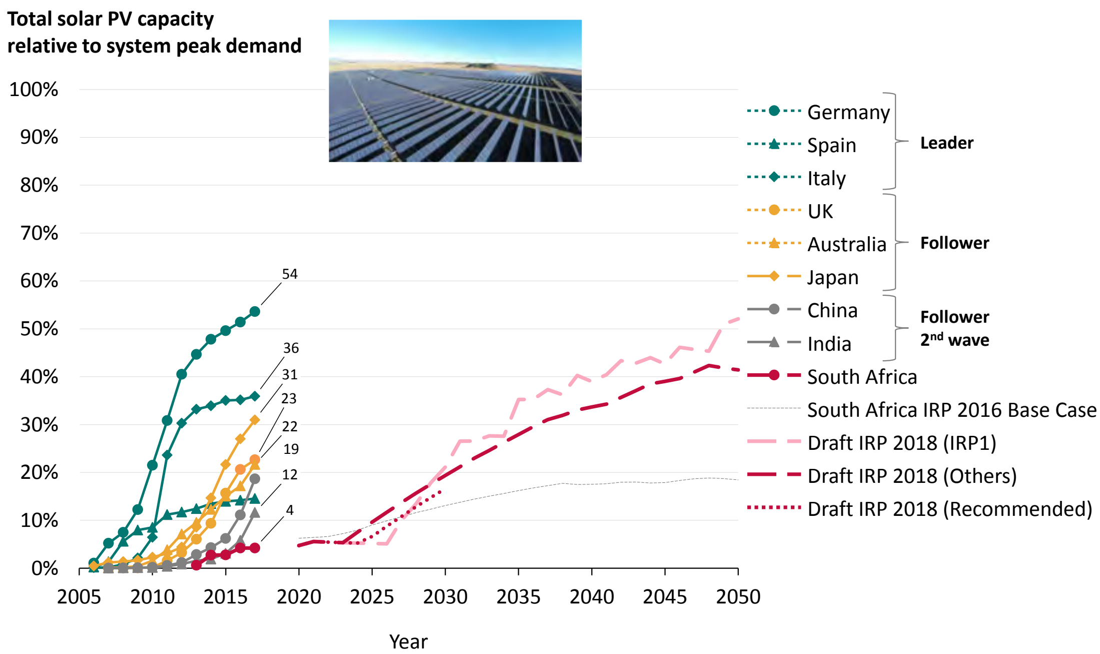
Already happening: Both leader and follower countries are installing more new wind capacity per year than South Africa's IRP limits for 2030/2050



117 Sources: GWEC; CIGRE; websites of System Operators; IRP 2016 Draft; CSIR analysis

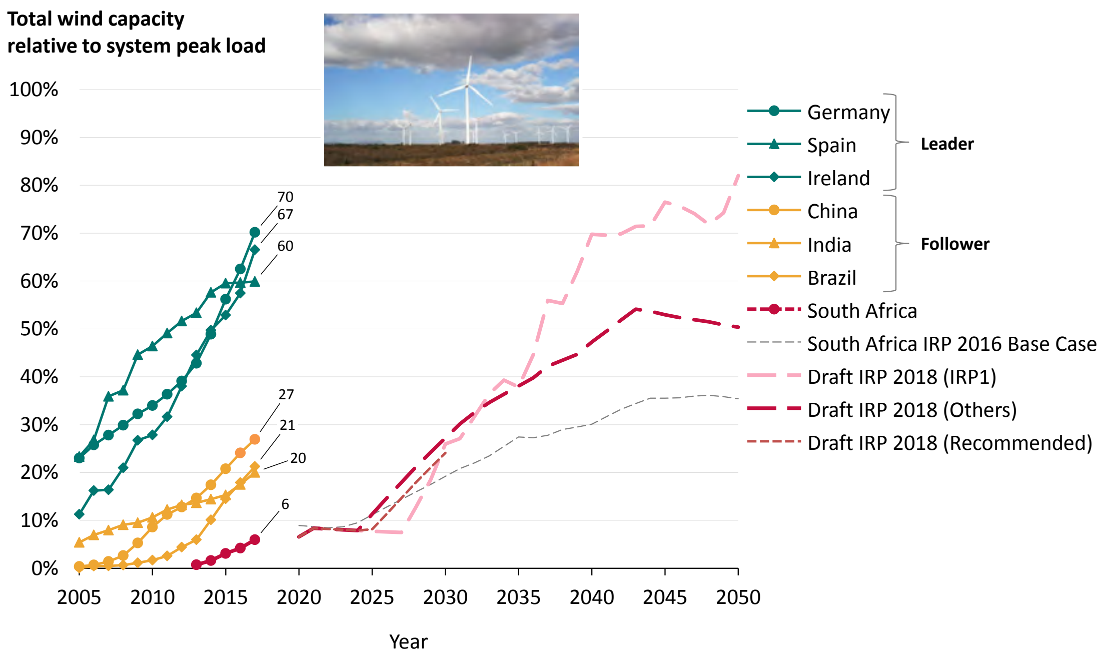
Figure 63: Global comparison of annual new-build limits on wind in Draft IRP 2018 with Leader and Follower countries

Solar PV penetration in leading countries already up to 1.3x levels expected in Draft IRP 2018 (constrained scenarios) by 2050



118 Sources: SolarPowerEurope; CIGRE; websites of System Operators; IRP 2016 Draft; CSIR analysis

Wind penetration in leading countries is already at levels up to 1.4x Draft IRP 2018 (constrained scenarios) by 2050



119 Sources: GWEC; CIGRE; websites of System Operators; IRP 2016 Draft; CSIR analysis

Figure 65: Global comparison of relative installed wind expected in Draft IRP 2018 scenarios relative to Leader and Follower countries

Figure 66 shows the total existing, under construction and committed capacity in South Africa based on the Draft IRP 2018. A specific focus on coal is also provided in Figure 67. It is clear that South Africa embarked on a significant and sustained new-build coal generation capacity programme which since the 1960s until the late 1980s. This was then followed by a slower but sustained new-build in the early 1990s and further into the 2000s. Following this, since 2015, Medupi and Kusile have started to be come online.

This new-build capacity expansion in coal generation capacity can be easily seen in Figure 68 where the annual new-build coal capacity is shown. At a high-level, this demonstrates the ability of the construction industry and necessary supporting infrastructure to undertake large capacity expansion in the electricity sector. It would be difficult to find sufficient reasons as to why South Africa could not repeat this for any

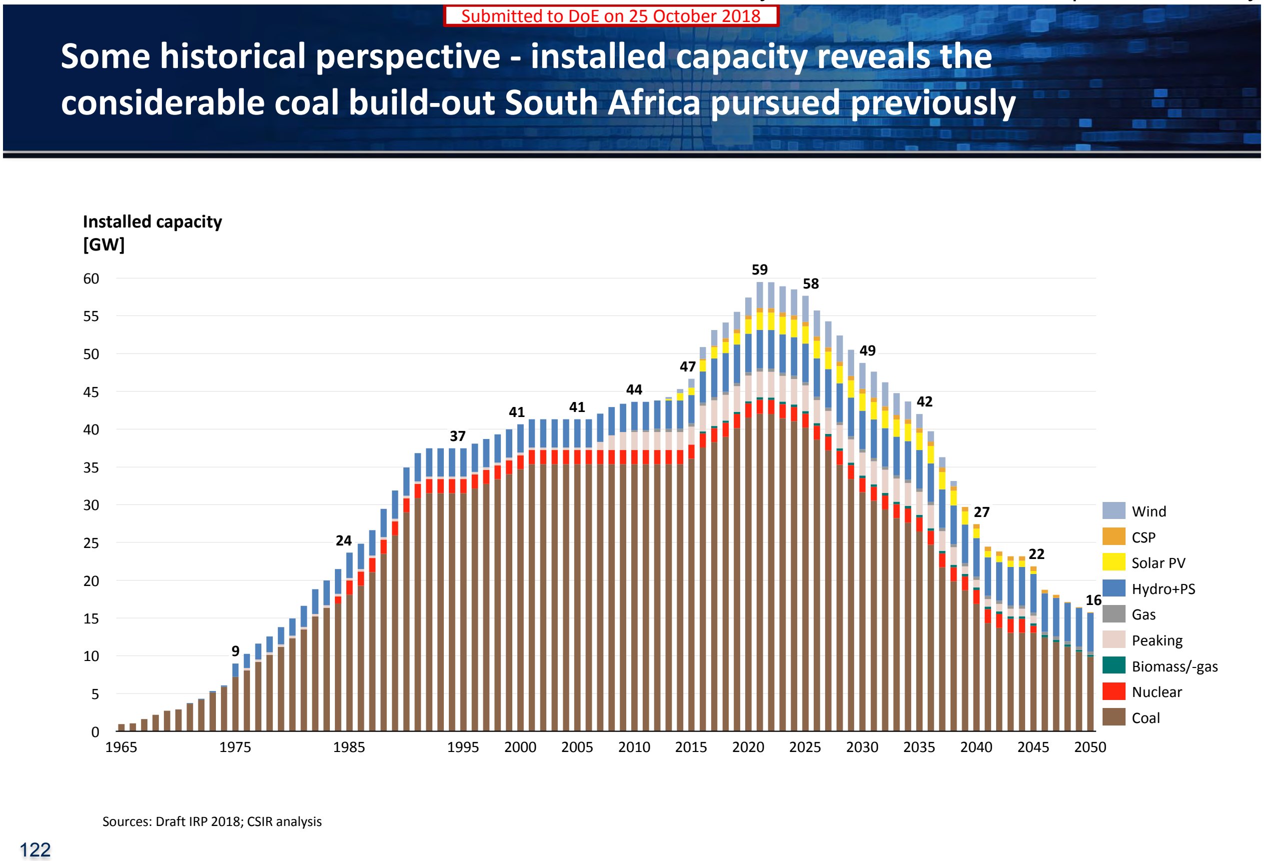
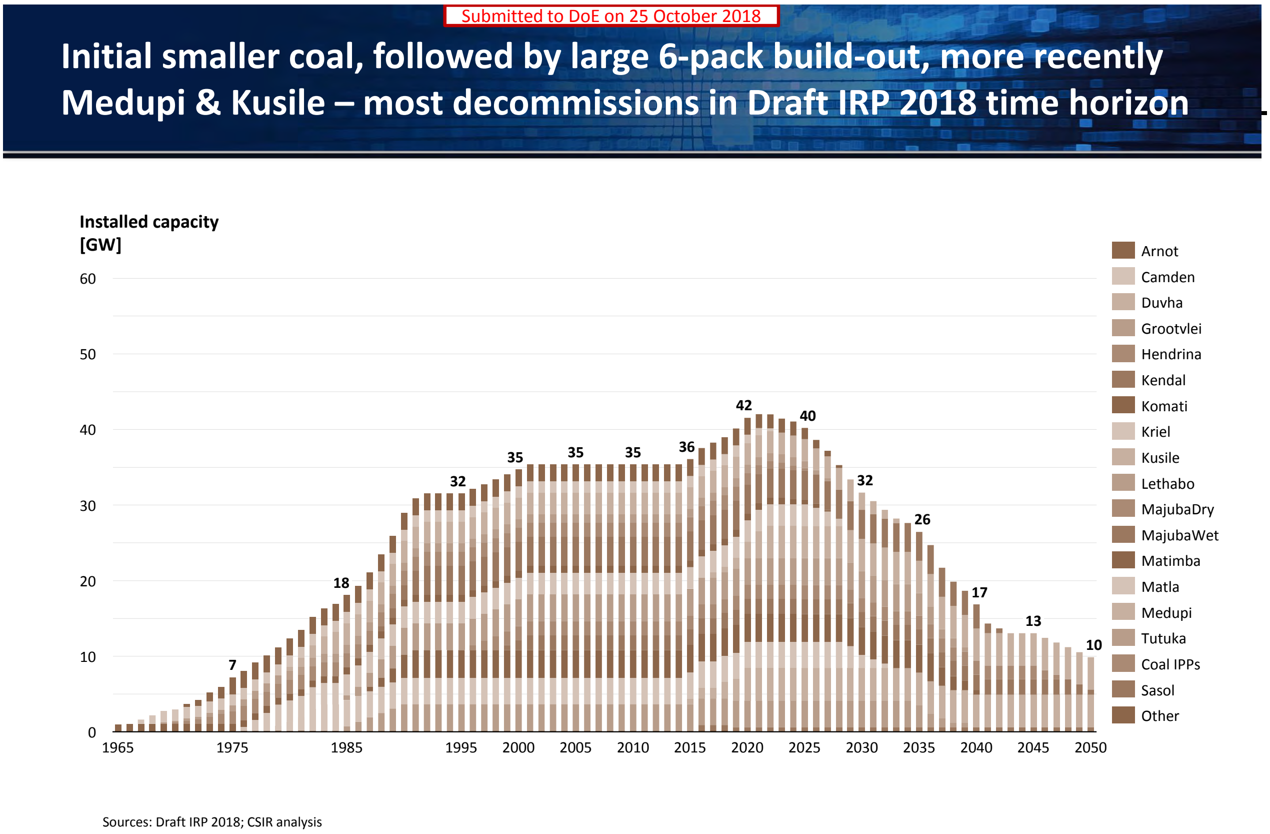


Figure 66: Total existing, under construction and committed capacity in South Africa for the period 1965-2050



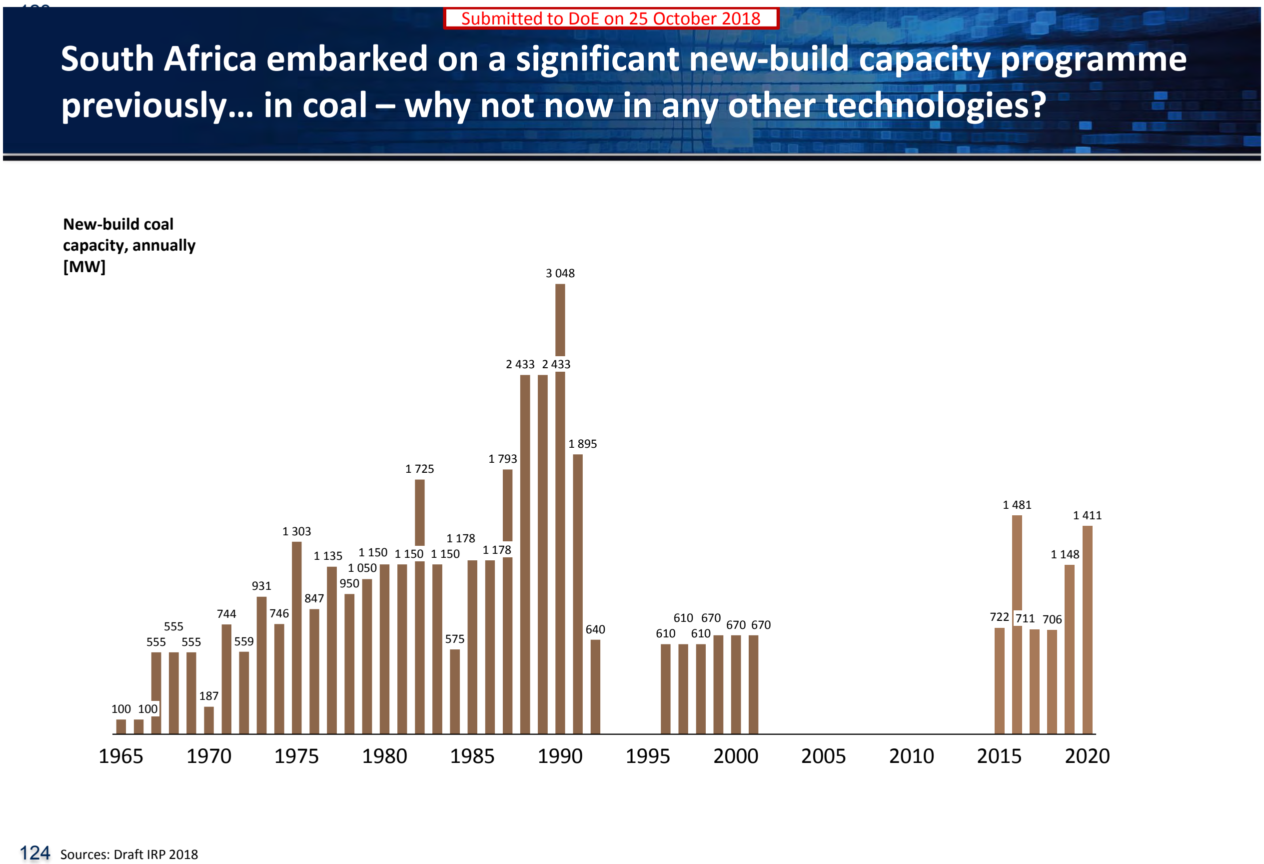


Figure 68: Annual new-build coal capacity deployed in South Africa for the period 1965-2020

4.2.2 Existing, under construction and new-build coal capacity

It is clear from the outcomes of the least-cost unconstrained outcomes of the Draft IRP 2018 (IRP1) that no new coal capacity is built. It is also clear that no new coal capacity is built pre-2030 in any of the Draft

IRP 2018 scenarios. Considerably reduced new coal capacity is built post-2030 if the Carbon Budget CO_2 emissions trajectory and new-build limits are imposed on solar PV and wind. Notable levels of new-build coal capacity are built though when a less restrictive CO_2 emissions trajectory is considered along with new-build limits on wind and solar PV.

As part of recent technical systems analysis undertaken by CSIR in [50] to support the published work in [51], an understanding of the viability of new-build, under construction and existing coal generation capacity in South Africa was pursued. This section will briefly outline this work to provide an understanding of the work undertaken and meaningful outcomes obtained.

The System Alternate Value (SAV) approach applied in [50] is summarised in Figure 69. The approach can be applied to any type of electricity generation technology but is specifically applied to a range of coal power stations in South Africa.

In order to calculate the SAV, two key cost components resulting from the presence of a particular power station (or set of power stations) are measured; namely:

a) The effect on the investment required for additional power generators needed to supply the residual load (when the power station or set of power generators under study are removed); and

b) The effect on the dispatch of existing and possible new power generators to supply the residual load i.e. their fixed and variable operations costs as well as fuel costs.

The steps listed below are followed for each power station (or set of power stations) under study to calculate their respective SAV (also represented graphically in Figure 69):

i A least-cost capacity expansion plan is run to determine a Base Case power system over the planning horizon. From this, the total present-value of all capital, fixed and variable costs for the system are calculated along with the present-value of the energy generated from the power station (or set of power stations) under study;

ii Step (i) is repeated with the power station (or set of power stations) under study removed at a particular date. This can take the form of an early retirement of a power station (relative to the expected decommissioning date) or discontinued construction of a committed/new power station. The difference in energy as well as capacity from removal of this power station (or set of power stations) will be replaced by a least-cost optimal supply mix including existing power stations as well as new-build supply options;

iii All costs associated with the power station (or set of power stations) under study are entirely removed from the total system cost of both (i) and (ii). This isolates the relative value difference provided by the power station (or set of power stations) and the set of existing and new-build supply options;

iv The absolute difference in total discounted system costs (the value difference) and the energy difference determined previously are then used to determine the equivalent System Alternative Value (SAV).

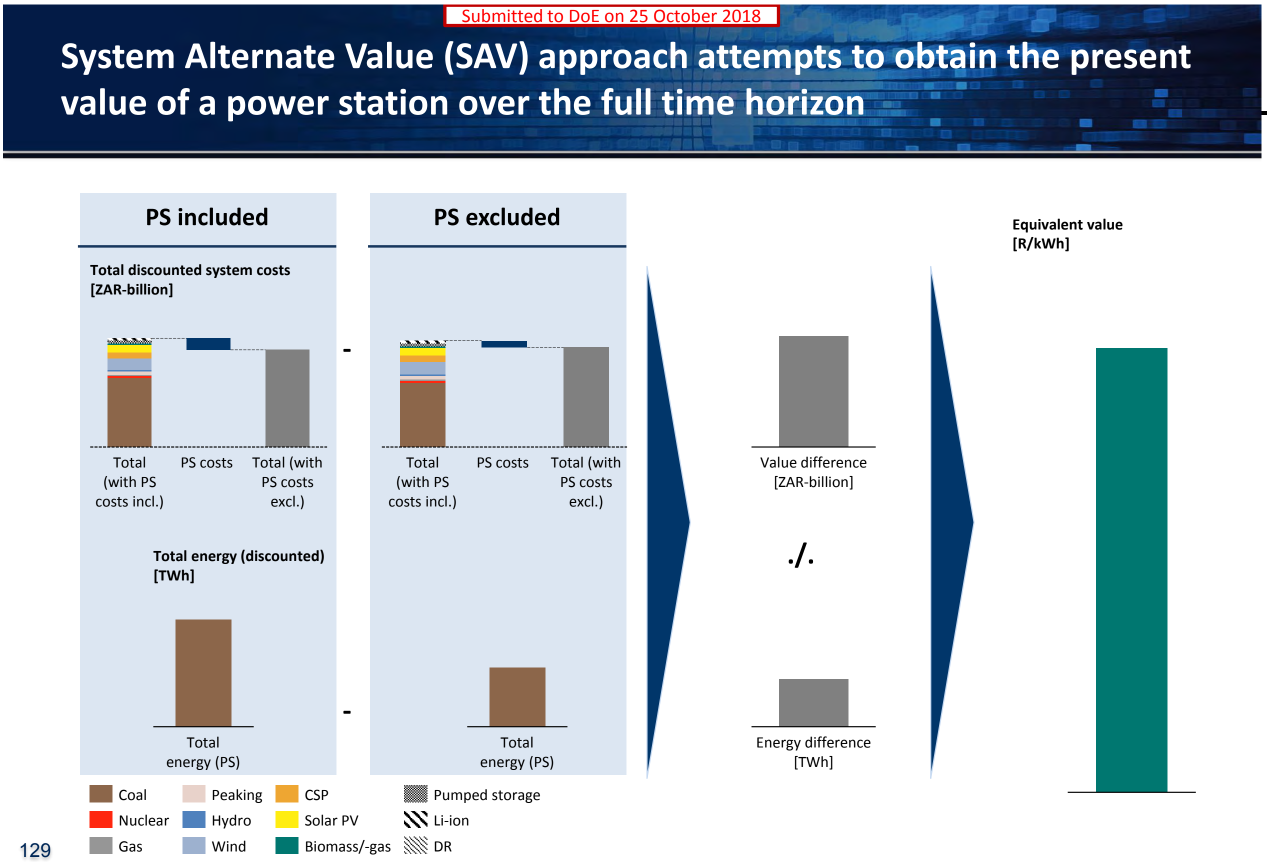
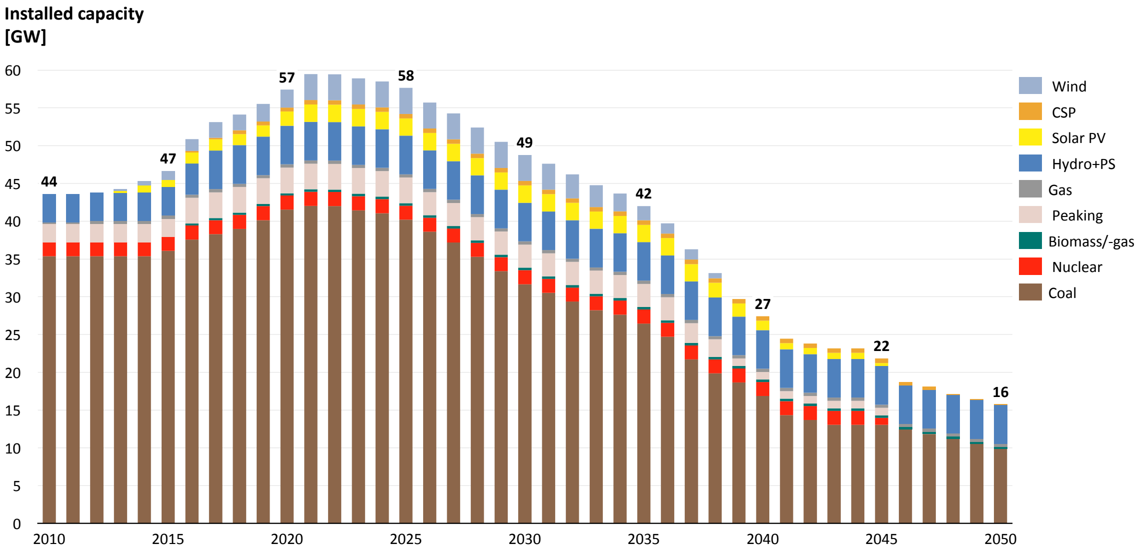


Figure 69: Summary of System Alternate Value (SAV) approach developed and applied in [50]

For reference, a zoomed view of the period 2010-2050 of the total installed capacity and expected decommissioning schedule of the total South African installed capacity and coal specifically is provided in Figure 70 and Figure 71 respectively. This is included to show how the coal fleet is expected to decommission in the long-term but intentionally zoomed into the 2010-2050 period to show short- to medium-term decommissioning expected(Grootvlei, Hendrina, Komati, Camden) as well as long-term decommissioning expected.

The outcomes from applying the SAV approach to the oldest coal generators as well as under-construction capacity (Kusile) is shown in Figure 72. As demonstrated, the SAV of the last two units at Kusile is 0.57-0.61 ZAR/kWh. Stated differently, when comparing this to the costs at Kusile as shown), the last two units at Kusile should be completed for less than the SAV. Otherwise, it would be more economically optimal to stop construction of these last two units and utilise alternatives. Similarly, the oldest existing coal capacity that was tested (Arnot, Camden, Grootvlei, Hendrina, Komati) showed a range of SAV. When comparing these to their costs to run and maintain, it is clear that for almost all of these old generating plants it would be more optimal to decommission these earlier and instead utilise alternatives (existing more efficient coal capacity and new-build natural gas, solar PV and wind capacity).

Even currently under-construction and committed capacity will be part of planned decommissioning and will require new-build



Sources: Draft IRP 2018; CSIR analysis

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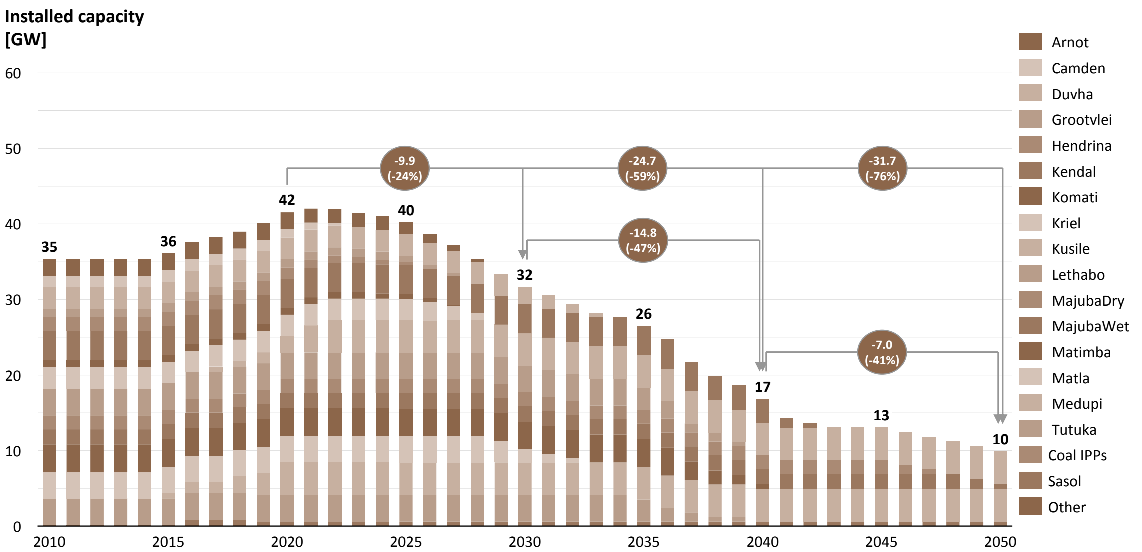
New-build largely driven by the planned decommissioning of the existing coal fleet - mostly post 2030



Sources: Draft IRP 2018; CSIR analysis

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Figure 71: Existing and under construction coal capacity from 2010-2050 in South Africa

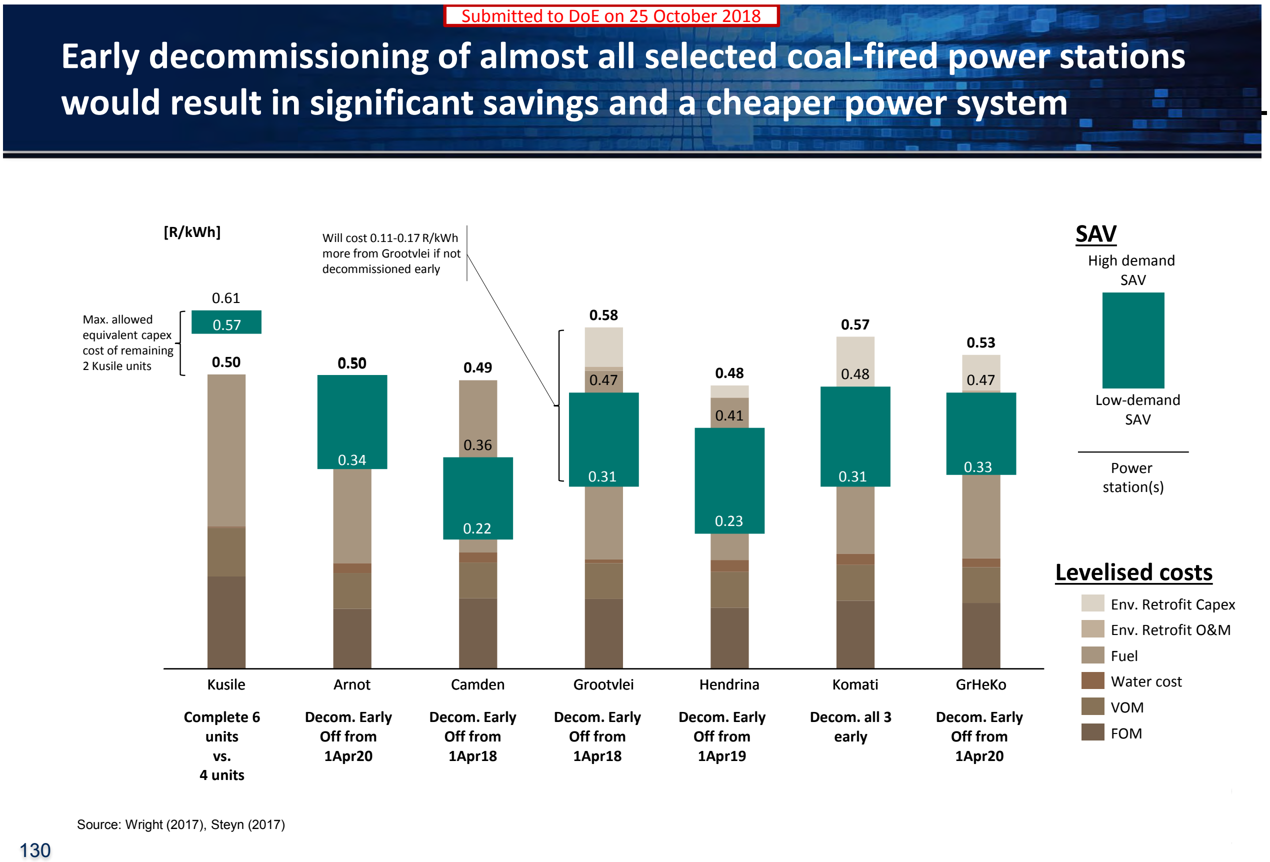


Figure 72: Outcomes of research undertaken in [50] applying SAV approach

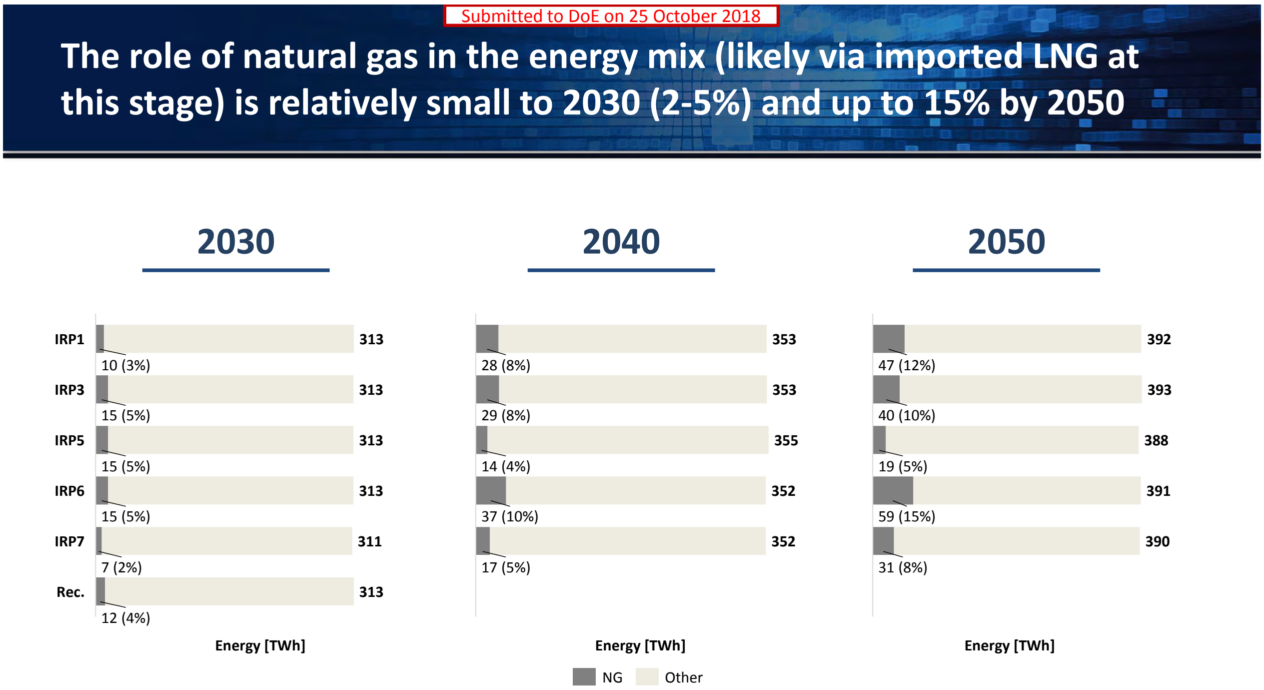
4.2.3 Natural gas

The deployment of gas-fired capacity is consistent across all Draft IRP 2018 scenarios with varying magnitude. The contribution of natural gas to the energy mix across these scenarios is summarised in Figure 73. Natural gas fired capacity contributes 2-5% of the energy mix by 2030 and 8-15% of the energy mix by 2050.

The expected cost of this natural gas (fuel only, based on the Draft IRP 2018) is shown in Figure 74. Natural gas (fuel only) is expected to contribute 2-4% of system costs by 2030 across all scenario and between 3-10% of total system costs by 2050. The natural gas that is used for the required flexible capacity is assumed to be based on Liquified Natural Gas (LNG) imports or regional pipeline gas (likely from Mozambique). Thus, the price assumption at which natural gas is obtained is considered to be quite expensive in most scenarios (135.7 ZAR/GJ, 10 USD/GJ) and even higher in IRP5 and IRP7 ("market linked", increases from 126 ZAR/GJ (9.3 USD/GJ) in 2017 to 190 ZAR/GJ by 2035 (14.0 USD/GJ) and constant thereafter).

These are important considerations as they put into perspective the role (in the energy mix and in cost) that imported natural gas is expected to play across all Draft IRP 2018 scenarios.

If the risk of imported natural gas is deemed considerable from a national energy security perspective and/or from a total system cost perspective (as a result of exchange rate changes, international market liquidity and/or supply/demand uncertainty), domestic sources of flexibility could mitigate these (relatively) small volumes of natural gas in the electricity sector. Examples of these include domestic sources of natural gas like Underground Coal Gasification (UCG), Coal Bed Methane (CBM), shale gas, offshore gas as well hydrogen or other technologies like biomass/-gas, CSP, mini-hydro or storage



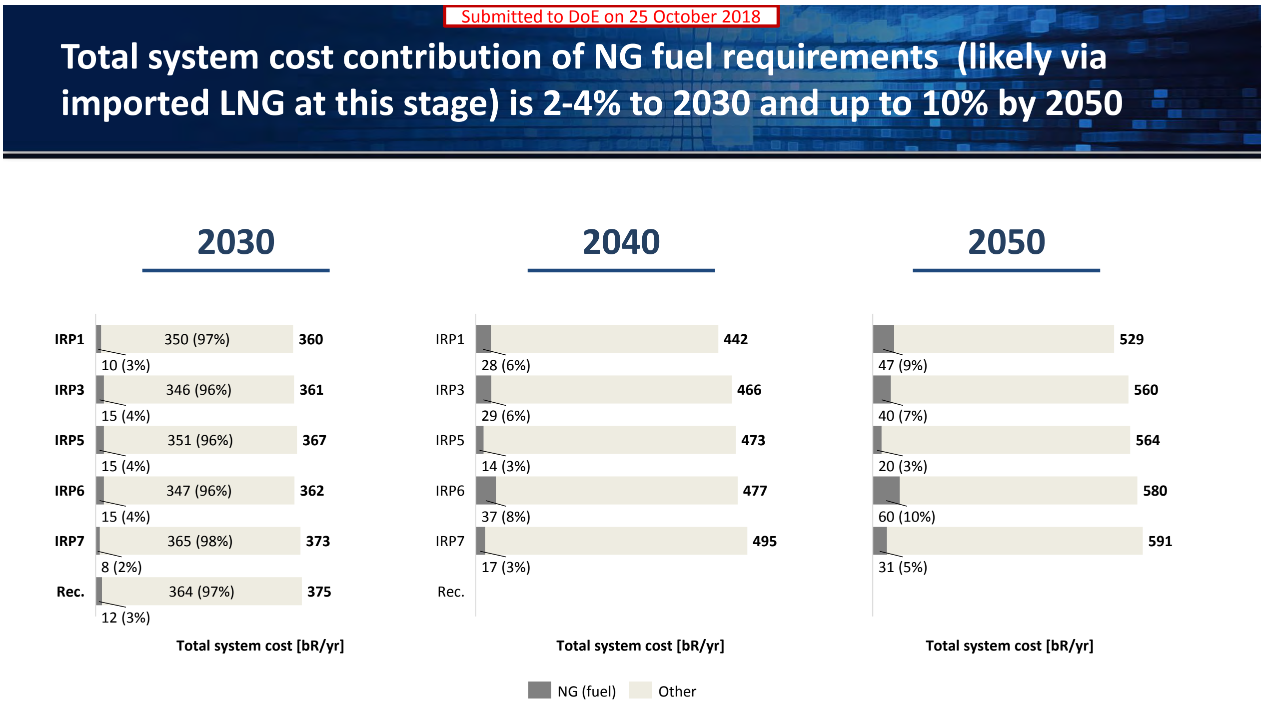


Figure 74: Summary of the expected cost of natural gas (fuel only) in the energy mix across Draft IRP 2018 scenarios

NG – Natural gas; Sources: Draft IRP 2018

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4.2.4 Planning for Embedded Generation (EG)

In 2013, the location of power generators in South Africa were mostly concentrated in Mpumalanga (Figure 75). In the short space of 5 years as seen in Figure 76, this has completely shifted with new generation capacity (largely driven by the REIPPPP) being distributed across the country with particular development in the Northern Cape, Eastern Cape and Western Cape. This trend is likely to further continue as distributed generation options (likely mostly driven by solar PV) will deploy in metropolitan environments as well as in other less concentrated settlement areas where generation capacity has not existed previously.

Overlaid on both Figure 75 and 76 is the existing as well as planned transmission backbone strengthening, the Renewable Energy Development Zones (REDZ) and strategic transmission corridors already being planned for (as discussed in section 5.1).

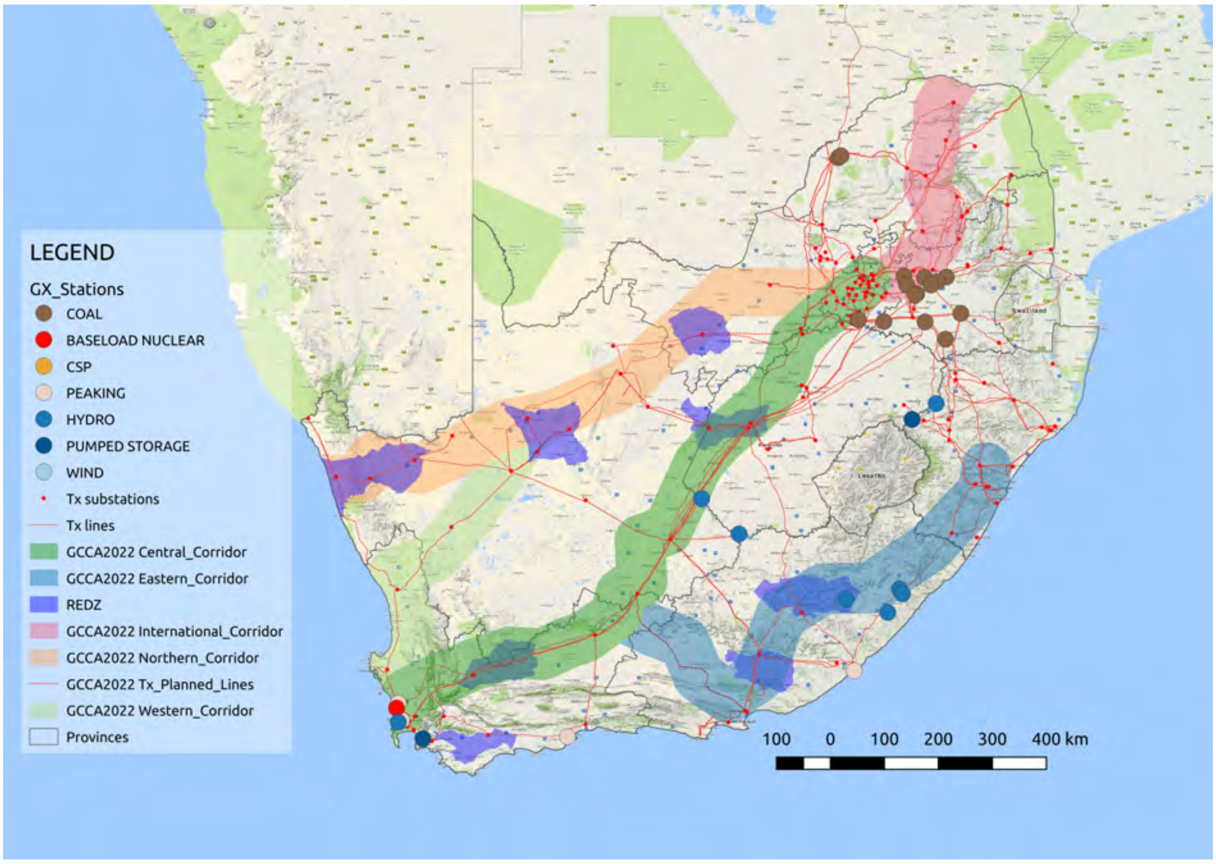

Figure 75: Location of large power generators in South Africa (2013)

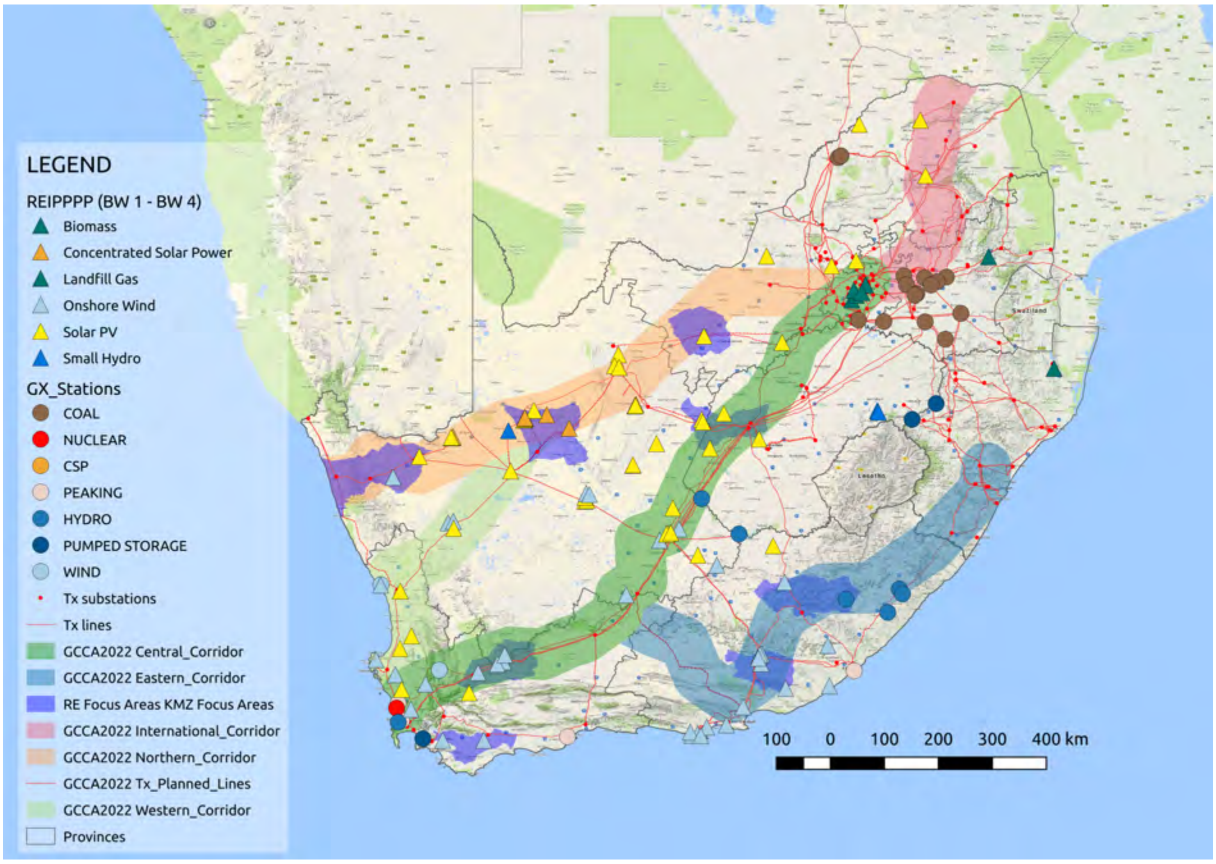

Figure 76: Location of large power generators in South Africa (2018)

The current approach to determining electricity demand in South Africa is shown in Figure 77. System load (which is what is planned for as part of the Draft IRP 2018) does not consider EG explicitly. Instead, this is assumed as negative demand (an overall reduced demand requirement).

The South African electricity balance for 2016 is summarised in Figure 78. The Draft IRP 2018 demand forecast is based on meeting this system load (with EG assumed to be implicit in reduced demand). The set of demand forecasts considered as part of the Draft IRP 2018 are summarised in Figure 79.

The Draft IRP 2018 is also very clear on the differences between the Median demand forecast and the Lower demand forecast. The Lower demand forecast is utilised to represent further Energy Efficiency (EE), fuel switching and EG relative to the Median demand forecast. Using this as a basis and parametrising the expected share of embedded generation in these differences, Figure 80 shows how much energy would be implicit as reduced demand if 20-80% of the reduced demand came from EG (dominated by solar PV). This equates to 5-19 TWh of EG and if all of this is assumed to be solar PV, this amounts to 1.1-5.8 GW by 2030 (80-420 MW/yr).

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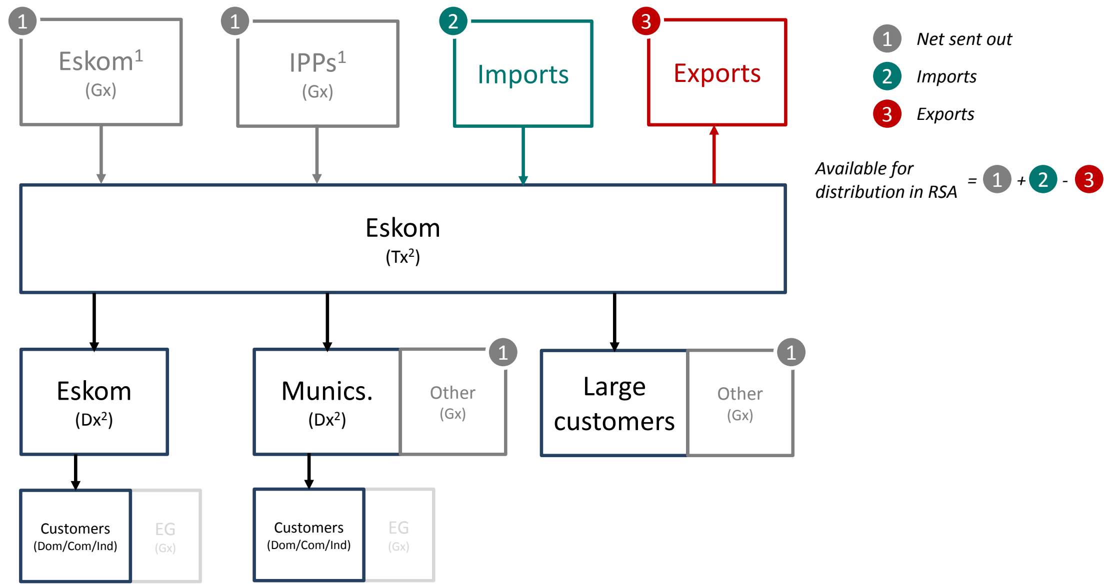
IRP meets energy demand for RSA – expressed as equivalent demand (assumes EG as reduced demand)



EG = Embedded Generation; Gx = Generation; Tx = Transmission; Dx = Distribution
[1] Power generated less power station load; Minus pumping load (Eskom owned pumped storage); [2] Transmission/distribution networks incur losses before delivery to customers

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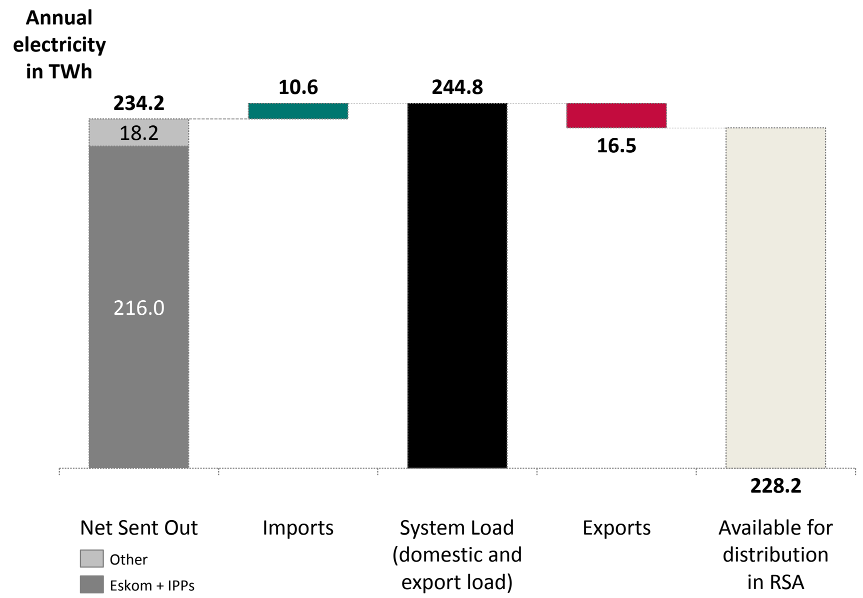
From Jan-Dec 2016, 234 TWh of net electricity was sent out in SA with imports of almost 11 TWh means system load was 245 TWh

Actuals captured in wholesale market for Jan-Dec 2016 (i.e. without embedded plants)



Notes: "Net Sent Out" = Total domestic generation (less auxillary load) minus pumping load of Eskom pumped storage stations (not shown seperately)
Sources: Eskom; Statistics South Africa

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Figure 78: Current approach to determining South Africa's electricity demand

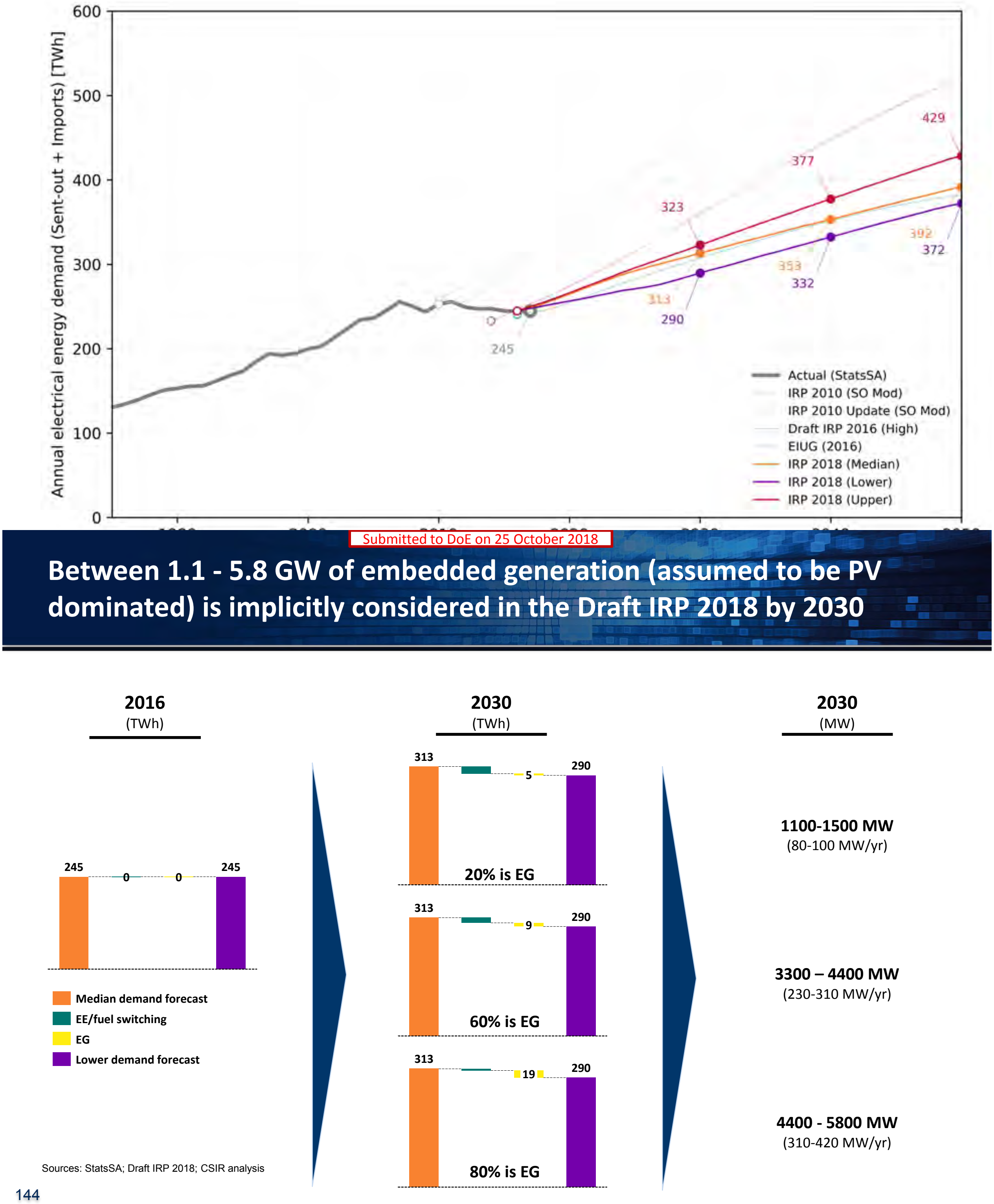

Figure 80: Implicitly assumed embedded generation already built into the difference in demand forecasts in the Draft IRP 2018 (assuming a range of embedded generation shares with energy efficiency and fuel switching)

4.2.5 Demand profile

The shape of the national demand profile being planned for in the Draft IRP 2018 is assumed to remain unchanged as the power system grows. This will not be the case in future as the constituent components of the demand forecast (agricultural, domestic, commercial/manufacturing, mining and transportation) shift based on the range of assumptions made on economic activity and associated energy use. A representative example of this is shown in Figure 81.

This change in demand profile will need to be factored into future iterations of the IRP likely following

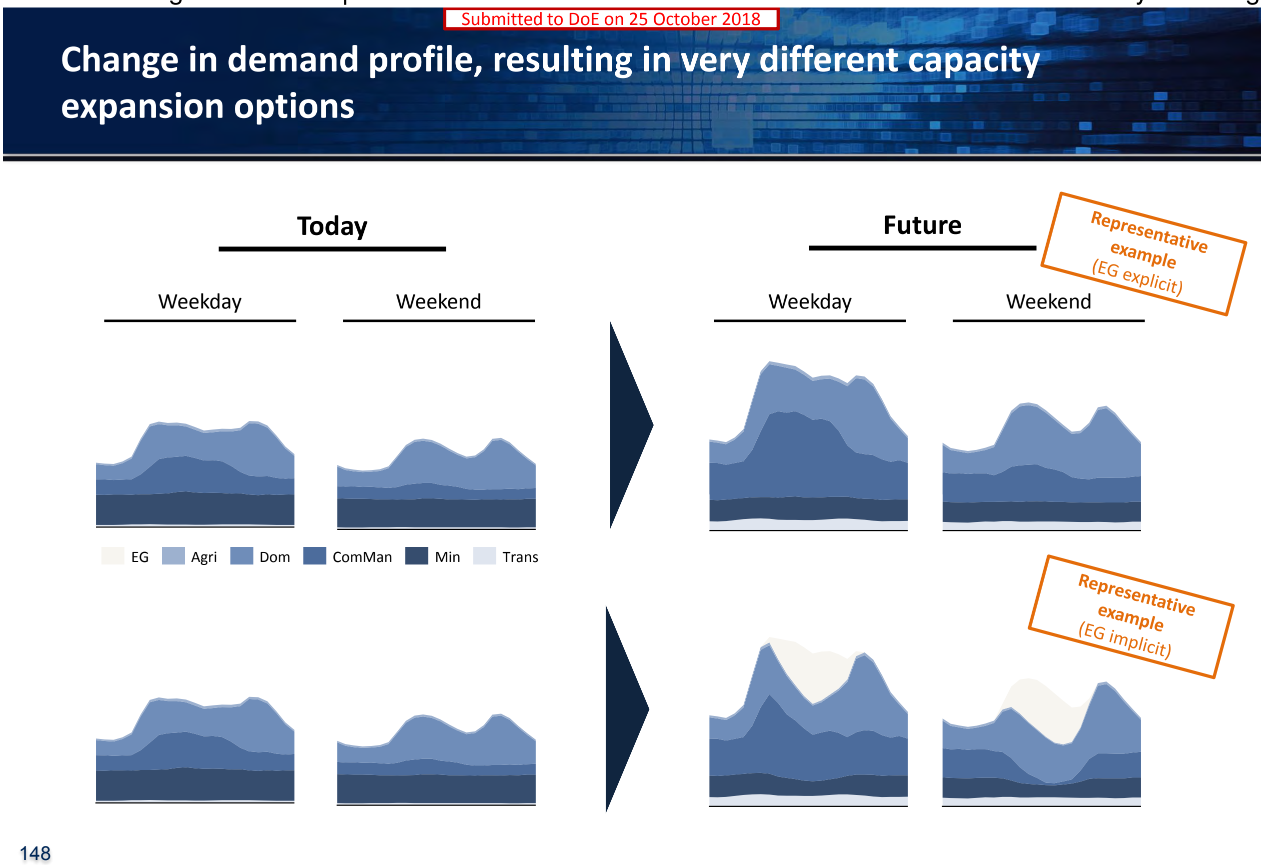

Figure 81: Represenative example of the changing South African demand profile as sectors of the economy grow, their associated energy use changes and EG adoption increases

5 Technical considerations

5.1 Transmission networks

As illustrated in Figure 23 previously with respect to the inclusion of network costs, collector network costs in the various Eskom Customer Load Networks (CLNs) as well as shallow grid connection costs for VRE (solar PV and wind) have been included in the Draft IRP 2018 [52]. The shallow grid connection costs for all other technologies have also been included [52]. This is a welcome inclusion and is a good starting point to start to incorporate technology specific costs previously not considered as part of the IRP process.

The design of collector network costs was based on experience gained from the integration of VRE generators as part of the REIPPPP with the objective of avoiding premature congestion at Eskom Main Transmission Substations (MTSs), minimising the absolute number of MTSs, connect more smaller VRE plants in a specific area and allows for more orderly network development and increased utilisation i.e. more efficient integration into the national grid. The network costs are based on unitised costing of high-level individual equipment costings from Eskom experience (transmission substations, satellite stations, transformers, transmission/distribution bays, overhead lines, Static VAr Compensators (SVCs)) needed to establish and expand collector networks as well as integrate into Eskom MTSs.

Deep network costs (backbone strengthening requirements) are not included as part of the IRP as these are established based on scenarios of generation expansion planning outcomes from the IRP and undertaken as part of the periodically updated TDPs and SGPs developed by Eskom Grid Planning [53]. What is most important considering the scenario-based approach taken as part of the IRP is how the relative cost of these deep network costs change across scenarios. Generally, these deep network costs do not change significantly across the range of scenarios considered and thus would not materially impact least-cost outcomes.

In future iterations of the IRP, there should be a continued pursuit to include geospatial components of supply, networks and demand side options. In this, co-optimisation of as many of these cost components along the supply chain would be co-optimised where deemed feasible and tractable.

5.2 System services

As introduced in the previous comments provided by CSIR on the Draft IRP 2016 [7, 8], with the integration of higher levels of cheaper VRE (specifically solar PV and wind) into a number of power systems around the world in recent years, the challenge now generally becomes one of technical system integration [54, 55].

A key driver into the future will be the appropriate valuation and disaggregation of the necessary products to incentivise market participants to provide these as required by System Operators (SOs). In South Africa specifically - capacity, energy and system services are largely bundled. These services will need to be made transparent and sufficiently unbundled in order to ensure that providers of each service can be identified and provide it as, when and where needed.

A growing component of the necessary products mentioned above will be that of system services. As existing synchronous generators are decommisisoned as planned, reduced system services will be provided from these providers as they have been provided "by default" historically. In the following sections, some key system services and how increased penetration of VRE will affect them are discussed. Some components from the previous CSIR comments on the Draft IRP 2016 are repeated here for ease of reference [7, 8].

5.2.1 Rate of Change of Frequency (RoCoF) and frequency stability

A particular focus is placed on frequency stability and frequency control (more specifically - system inertia) as this seems to be the most significant concern from SOs around the world when integrating high levels of VRE that are typically non-synchronous (inverter-connected) [3].

A challenge that is experienced with increased penetration levels of non-synchronous generation is the erosion of natural inertial energy (stored rotational kinetic energy) that is provided by synchronous machines. Inertial energy from synchronous machines can be defined as resistance to change in motion on the machines due to system frequency disturbances such as loss of a large generator or load. This natural inertial response from synchronous generating sources helps in damping frequency excursions during system events such as generator trips or sudden loss of large loads or transmission infeeds. The non-synchronous inverter-based generation does not naturally possess inertial energy. With depleting inertial energy, the RoCoF following large disturbances could increase so much so that primary frequency response and sometimes Under Frequency Load Shedding (UFLS) schemes may fail to protect the system. This has become a notable focus for SOs in a number of jurisdictions globally as non-synchronous penetration levels increase.

The initial system RoCoF following a large disturbance (loss of generation/load and/or transmission import/export) is predominantly dependant on the amount of system inertia on the network at the time of the disturbance. A stylised representation of the RoCoF is shown in Figure 82 [56] for the loss of a large generator and/or transmission infeed (imports). The term "inertia" when used in this context actually refers to the total amount of kinetic energy that is stored in the rotating masses of all synchronously connected generators (and loads). Using the well known swing equation [57], linearised over the small disturbance range and removing primary frequency control (to be as conservative as possible), one can derive the minimum amount of system inertia required at any time to ensure that the RoCoF remains below a pre-defined threshold:

$$E_{kin.(min)} = P_{cont.} \frac{f_n}{2(\text{RoCoF})} + E_{kin(cont.)} \tag{1}$$

[3] The authors appreciate that there are other areas that need sufficient planning, investment and operational experience but the system inertia concern is ubiquitous and is thus a particular focus

where

$E_{kin.(min)}$	=	Minimum system inertia i.e. minimum synchronous system energy required;
f_n	=	System frequency (50 Hz);
$P_{cont.}$	=	Size of largest contingency (MW);
RoCoF	=	Pre-defined acceptable RoCoF (Hz/s);
$E_{kin(cont.)}$	=	Amount of energy lost in contingency (MW.s).

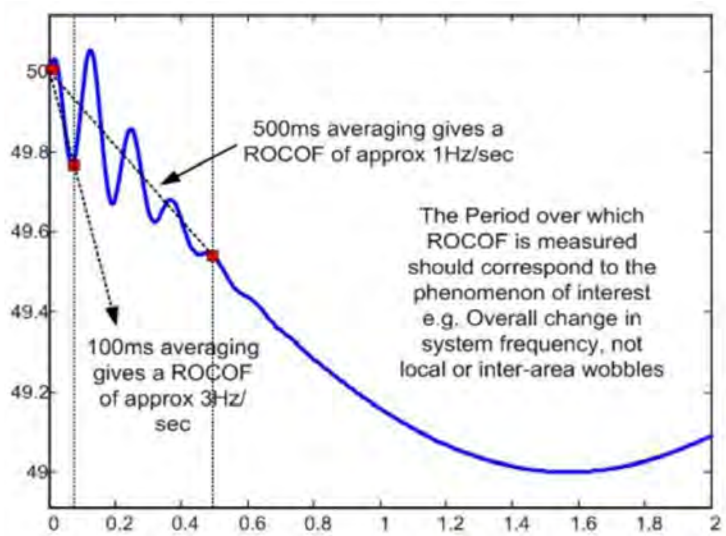

Figure 82: Illustration of RoCoF following a large contingency event (measured over different averaging windows) [56]. Typically, averaging window is 500 ms as this is the phenomenon one is interested in (not localised and/or inter-area modes/oscillations).

5.2.1.1 Estimating an acceptable system inertia based on RoCoF

Using equation 1 and assuming an acceptable RoCoF as well as reasonable contingency size, one can define the amount of synchronous system energy ("system inertia") that needs to be in the system at any point in time to ensure the pre-defined RoCoF is not exceeded. Assuming the following:

- $P_{cont.}$ = 2 400 MW (loss of three large coal units simultaneously);
- RoCoF = 0.5 Hz/s;

The choice of RoCoF = 0.5 Hz/s is adjusted relative to the previous comments provided by CSIR on the Draft IRP 2016 in order to remain even more conservative than previously was the case [4].

From these input assumptions, the minimum amount of system inertia required would be $\approx$ 125 000 MW.s . This defines the minimum amount of system inertia that needs to be in the power system for all hours of the year.

[4] Ireland has recommended 1 Hz/s [58, 59]. The South African Grid Code (for renewables) requires a RoCoF = 1.5 Hz/s at this stage [60].

5.2.1.2 Estimating an acceptable system inertia based on existing operations

As an alternative approach, considering a previous operating year as the starting point, if one assumes that the SO operated the South African power system with sufficient inertia in this year, then going forward - at least this amount of system inertia would need to be available for all hours of the year.

This has been calculated for 2016 where the minimum system inertia was $\approx$ 104 500 MW.s . The basis for this is the simulated hourly unit commitment and economic dispatch for the South African power system for 2016. This is calculated based on assumptions for typical inertia constants for all generator technologies. This system inertia is then ordered to obtain an inertia duration curve. The minimum system inertia was then established.

5.2.1.3 Expected future system non-synchronous penetration (IRP1)

In order to determine the "worst-case" System Non-Synchronous Penetration (SNSP) to be expected in future, the IRP1 scenario from the Draft IRP 2018 is considered.

System Non-Synchronous Penetration (SNSP) is a relative measure of the amount of instantaneous non-synchronous penetration relative to the power system demand at any moment in time and can be mathematically expressed as:

$$SNSP = \frac{P_w + P_{pv} + I_{HVDC}}{D_s + E_s} \tag{2}$$

where

$SNSP$	=	System non-synchronous penetration;
P_w	=	Wind production (MW);
P_{pv}	=	Solar PV production (MW);
I_{HVDC}	=	Imports via HVDC (MW);
D_s	=	System demand (including network losses) (MW);
E_s	=	Exports (MW)

The SNSP is an important metric as it provides insight into when the system may be vulnerable to having low levels of inertia. If a large disturbance were to occur during these periods a high RoCoF would result if no remedial action was taken or mitigating solution implemented.

The expected future system SNSP for the IRP1 scenario (most aggressive on non-synchronous penetration levels) ordered similar to a Load Duration Curve (LDC) is shown in Figure 83. As can be seen, there are relatively low levels of non-synchronous penetration before 2030 where SNSP levels are only above 37% by 2030 for 10% of the time but with a maximum SNSP of 60%. EirGrid have set maximum SNSP at 60% today and are aiming for 75% by 2020. Post-2030, SNSP levels increase notably with maximum SNSP levels of 80% by 2040 and almost 90% by 2050. However, as the power system transitions towards 2040 and 2050, new flexible capacity in the form of OCGTs, Internal Combustion Engines (ICEs), CCGTs and Combined Cycle Gas Engines (CCGEs) assist in providing inertia (replacing existing capacity as it decommissions). This is further expanded on section 5.2.1.4.

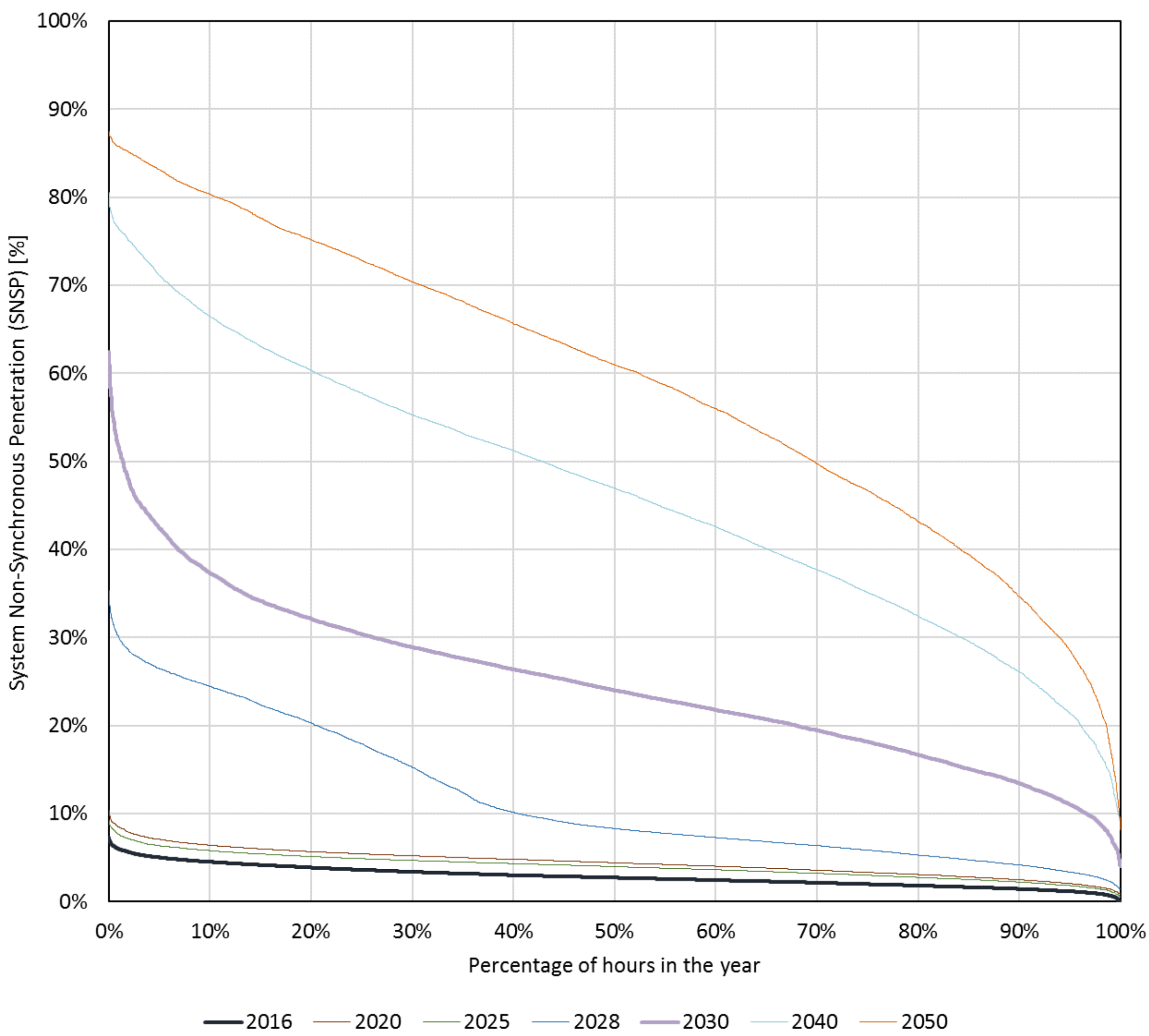

Figure 83: Expected system non-synchronous penetration for IRP1 scenario of the Draft IRP 2018 for 2016, 2020, 2030, 2040 and 2050 (this is the scenario with the highest VRE penetration levels)

5.2.1.4 Expected future system inertia (IRP1)

In order to determine the "worst-case" minimum system inertia to be expected in future, the most aggressive VRE scenario (IRP1) is considered. The hourly unit commitment and economic dispatch solutions for the scenario in 2020, 2025, 2028, 2030, 2040 and 2050 are established following which the amount of system inertia online for all hours of the year is calculated. This is based on assumptions for typical inertia constants for all generator technologies. This system inertia is then ordered to obtain an inertia duration curve. The previously calculated minimum system inertia (section 5.2.1.1) or system inertia from previous experience (section 5.2.1.2) are then overlaid onto this. The amount of system inertia each scenario lacks (if any) and the number of hours for which the system has insufficient system inertia can then be calculated.

It is important to note that any technology coupled through a power electronics interface (solar PV, wind, generators coupled via High Voltage Direct Current (HVDC) interconnection) do not contribute to system inertia. However, there is the potential for these technologies to provide synthetic inertia but this is not considered in this analysis in order to remain conservative.

Results from the analyses for the IRP1 scenario are summarised in Figure 84. A summary is provided in Table 4. System inertia in 2016 was already below the minimum required inertia previously calculated but only by a small margin (125 000MW.s relative to the 104 500 MW.s in 2016) and is expected to remain below this level by 2020. The SO has not yet indicated any concerns with SNSP or inertia (and expected RoCoF levels) and thus it is concluded that a system inertia of ≈110 000-125000 MW.s is sufficient to ensure acceptable RoCoF performance. System inertia levels actually grow from 2016 onwards primarily as a result of the power system growing but also driven by the introduction of natural gas fired generation capacity (with a higher H constant than existing and new-build coal capacity).

Beyond 2030 and towards 2040, the IRP1 scenario requires up to ≈58 000 MW.s of additional system inertia for ≈1 800 hours of the year (20% of the year). By 2050, up to ≈72 200 MW.s of additional inertia would be needed for ≈2 000 hours of the year (23% of the year) if existing levels of system inertia are required in future.

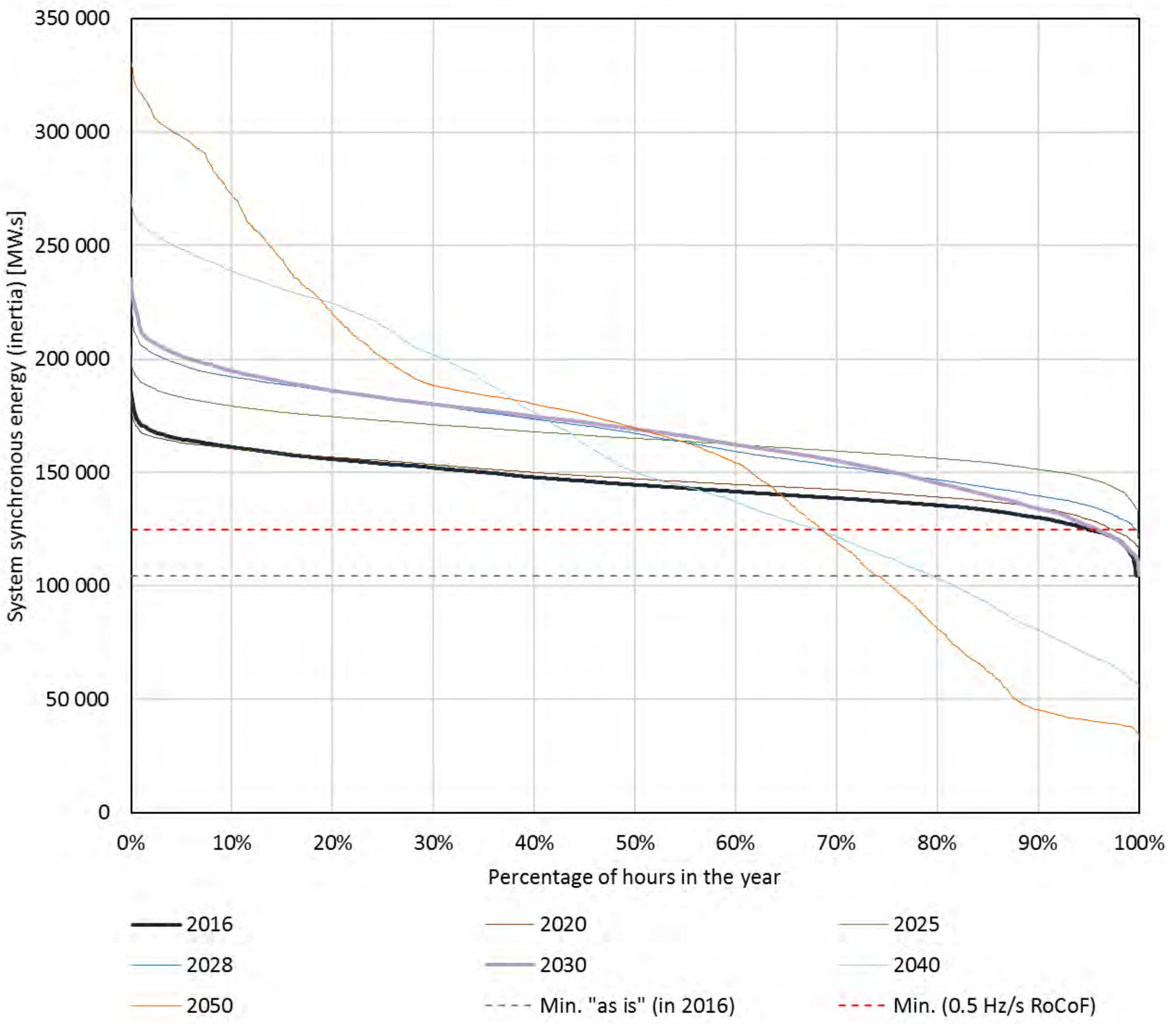

Figure 84: Expected system inertia (system synchronous energy) and reference system inertia requirement for IRP1 scenario of the Draft IRP 2018 for 2016, 2020, 2030, 2040 and 2050 (this is the scenario with the highest VRE penetration levels)

In principle, there are two ways to deal with lower system inertia:

i **Conservative:** Introduce additional intrinsic inertia (synchronous inertia) to reduce RoCoF; or

ii **Progressive:** Introduce reactive measures and control algorithms to deal with an increased RoCoF i.e. synthetic inertia.

Although a range of solutions in the progressive approach are available and a number of investigations and operational experiences have been outlined for a range of jurisdictions already [61, 62, 63, 64, 65, 66, 67, 68, 69, 70, 71, 72, 73, 74], the approach taken is to only outline the technical solutions in the conservative approach to increase system inertia and reduce RoCoF. These technical solutions are [56]:

- Synchronous compensators that are new purpose built devices and retro-fitting of decommissioned generators, with/without flywheels;
- Rotating stabiliser devices typically a multi-pole device incorporating a flywheel, which can be based on a Doubly-Fed Induction Generator or synchronous machine;
- Wind turbines: Only when directly coupled (typically with doubly-fed induction generators);
- Pumped hydro generators assuming synchronous machines are deployed;
- "Parking" conventional generators i.e. operating generation plant at low output levels but with reduced/no capability to provide system services (like operating reserves) at the lower output levels;
- Reduction in the minimum stable level thresholds of conventional generation while still leaving the plant with the capability to fully provide system services;
- New flexible thermal power plants with high inertia constants.

Of these mitigation measures that can be considered to address RoCoF, most of the "conservative" options are already in existence and could be leveraged to improve RoCoF performance whilst others in the "progressive" category like fast frequency response systems (FFR), synthetic inertial response systems from wind turbines are still at an early stage of development and understanding. RoCoF is of particular concern mainly in power systems that are small and not well interconnected with neighbours. South Africa is a large power system but is not very well connected with neighbours. Thus, it would be prudent to obtain the necessary frequency control services domestically. Other SOs with similar network architecture to that of the South African power system like EirGrid (Ireland), ERCOT (Texas, U.S.A) and AEMO (Australia) have made significant progress in understanding learning and actively managing increased non-synchronous penetration levels.

Going forward, although existing technologies and operating philosophies are being applied globally, there is a need to further develop these to address this phenomenon. This could involve designing a new suite of ancillary services such as provision of synthetic inertia, increased DSR and FFR capabilities. Grid Code reviews and the development of new frameworks will be necessary. Furthermore, it will become important to sufficiently cost inertia as part of future iterations of the IRP. This is undertaken as part of the comments provided for the IRP1 scenario.

5.2.1.5 Costing system inertia needs (IRP1)

To cost system inertia in the most conservative manner possible, the installation of a fleet of rotating stabiliser devices (directly coupled flywheels) is assumed. It is appreciated that this is not the optimal solution but it is the most conservative approach in that it costs system inertia in the most "expensive" manner possible in order to establish a worst-case maximum cost to address insufficient inertia. The rotating stabilisers are assumed to be connected to the power system for all hours of the year (even though they may only be required for a selected number of hours). The costs for additional system inertia via the deployment of a fleet of flywheels (as required per scenario) is summarised in Table 4 (assuming typical technical characteristics, investment and operations costs for rotating stabilisers as shown).

As can be seen in Table 4, only beyond 2030 does system inertia start to become a concern. Additional costs for rotating stabilisers beyond 2030 are only ≈1% of total system costs (worst-case). This is considerably less than the difference between the Least-cost scenario of the Draft IRP 2018 as well as other scenarios presented by in this submission.

Table 4: Summary of system inertia requirements and associated "worst case" costs to ensure acceptable RoCoF levels for IRP1 scenario from Draft IRP 2018 for 2016, 2020, 2025, 2028 2030, 2040, 2050

		2016	2020	2025	2028	2030	2040	2050
Minimum inertia needed	[MW.s]	104 482	104 482	104 482	104 482	104 482	104 482	104 482
Minimum inertia (actual)	[MW.s]	104 482	116 485	116 609	122 260	104 992	55 832	31 907
Additional inertia needed	[MW.s]	-	-	-	-	-	48 650	72 575
Number of hours	[hrs]	24	-	-	-	-	1 799	2 282
Share of hours	[%]	0.3%	0.0%	0.0%	0.0%	0.0%	20.5%	26.1%
Rotating stabilisers needed	[MW]	-	-	-	-	-	1 220	1 810
Annual cost for rotating stabilisers	[bR/yr]	-	-	-	-	-	3.7	5.6
(% of system costs)	[%]	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	1.2%

5.2.2 Transient stability and fault level ("system strength")

Transient stability is the ability of the power system to maintain synchronism when a large transient disturbance occurs (typically an electrical fault) [57]. More specifically, it is the ability of synchronous generators to maintain synchronism with eachother by ensuring that rotor angle deviations are not too large to then lose synchronism (as governed by the well known power-angle relationship). The amount of time that a fault can remain on the network before synchronism is lost is known as the Critical Clearence Time (CCT) and is the maximum time a fault can remain on the power system before which generators lose synchronism. The CCT is used as a determining factor when performing power system planning with particular reference to requirements in the Grid Code within which the analysis is being performed [75]. If with the addition of a new power generator, CCTs increase, the impact of the new power generator is positive and vice versa. Increased transient stability of the power system is tightly linked to "system strength" (high fault levels). Thus, as the penetration of inverter connected generators (like solar PV and wind) increases, this would need to be carefully understood and considered to ensure sufficient system strength across the power system in order to ensure acceptable transient stability, voltage stability and expected protection operation.

With specific reference to wind and solar PV generators, these generators are likely to be interfaced via power electronics and thus their impact on transient stability will be indirect (positive or negative). In this regard, an example of a positive impact is the improvement of power transfers (in the case where they are installed in exporting areas). An example of a negative impact would be the reduced synchronising torque between remaining synchronous generators in different areas. The impact will depend on the specific situation and thus the standard and well established grid planning approach should be followed when conducting the integration studies (as is already the case within Eskom).

At an operations level, tools and facilities can be deployed by the SO (as is being done by many SOs around the world, including Eskom) to assess transient stability in real-time. An example of this is the deployment of synchronised wide area monitoring (synchrophasors) for real-time system awareness as well as improved integration with online monitoring tools e.g. DSATools suite developed by Powertech [76] and specifically Transient Security Assessment Tool (TSAT) in this case [76]. Tools like these (as well as others) are being integrated into the Energy Management System (EMS) of SOs around the world in order to assist in ensuring system security and stability. More specifically with higher penetrations of VRE, the specific tool developed for and being applied by EirGrid/SONI in Ireland, Wind Security Assessment Tool (WSAT), is an example of what is available (or could be developed in South Africa) to better manage and integrate high VRE penetrations in South Africa.

5.2.3 Reactive power and voltage control

Reactive power is locational and thus needs to be procured in specific supply areas to ensure acceptable voltage levels as well as voltage control capability. The distributed nature of solar PV and wind could act in their favour in this regard as well designed procurement can geographically spread these around the country thereby ensuring acceptable voltage levels and reactive power control is available in areas where it is needed. However, it is appreciated that many wind and solar PV generators may be integrated at distribution voltage levels meaning voltage control at transmission level may become more complex[5]. If it is not optimal or feasible to place wind or solar PV plants in the requisite locations for this, other devices may need to be deployed to ensure the system service is obtained e.g. existing and future synchronous generators as well as reactive power control equipment like strategically placed capacitor/reactor banks, SVCs, Static Synchronous Compensators (STATCOMs) or Synchronous Condensors (SCOs). It is important to also remember that non-synchronous inverter connected generation do not only provide active power but can also provide necessary reactive power and voltage both statically and dynamically.

In South Africa, static as well as dynamic reactive power and voltage control is a pre-requisite for grid connection for particular size renewable energy generators as defined in the Grid Code [60]. Modern utility-scale wind turbines and solar PV inverters combined with their plant level controllers are designed for and capable of static and dynamic reactive power control similar to what conventional synchronous power generators are capable of.

[5] Voltage control is also done at distribution level where transformer on-load tap changers (OLTCs) assist.

Reactive power compensation requirements are informed by typical grid planning processes and is currently undertaken by Eskom (this should also continue into the future). Examples of this include the TDP [77], SGP [78] and Grid Connection Capacity Assessment (GCCA) [79]. Similar to tools being applied at system operations level for transient stability, similar tools and facilities can be deployed by the SO for voltage stability and security e.g. Voltage Security Assessment Tool (VSAT) complemented by tools like WSAT.

In summary, with already existing relevant grid planning and design approaches applied in South Africa, reactive power and voltage control requirements should not become a significant challenge in future as the penetration level of non-synchronous inverter connected generation sources increases.

5.2.4 Variable resource forecasting

Considering the expected growth in VRE in all scenarios of the Draft IRP 2018, the SO will need to be equipped with the relevant tools and skills to operate and manage the power system securely and reliably. VRE forecasting with sufficient levels of accuracy in a number of time-frames (15-minute ahead, hour-ahead, 12 hour-ahead, day-ahead and further) will become more important for the SOs to accurately dispatch and schedule capacity to ensure grid stability and the security of supply.

Tools and best practices are already being applied around the world in this regard and South Africa has the opportunity to leverage off of this whilst building local capacity and infrastructure to ensure a level of preparedness to ensure variable resources can be forecasted and associated risk managed accordingly. Examples of global variable resource forecasting being applied in system operators around the world include Germany [80, 81], Texas (USA) [82], Ireland [83] and Denmark [84] to name a few.

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