# Future wind deployment scenarios for South Africa

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## Abstract

South Africa has historically had a predominantly coal based energy system and a particularly coal dominated electricity system due to a large domestic coal resource and favourable coal generation technology economics. A more recently well understood wind (and solar) resource in South Africa combined with large geographical land-area and technology cost reductions globally and domestically for wind and solar photovoltaics (PV) has made these technologies more than competitive with alternatives. As a result, wind (and solar PV) have significant roles to play in the future South African electricity system. The potential role of wind in particular is quantified in this research where a least-cost scenario-based electricity sector capacity expansion planning exercise is undertaken. The results of this show that a considerable deployment of wind into the future should be expected where in least-cost scenarios ≈15-25 GW of installed wind capacity by 2030 (≈10-20% of the energy mix), ≈40-60 GW by 2040 (≈20-40% of the energy mix) and ≈60-85 GW by 2050 (45-50% of the energy mix) is cost-optimal. By 2050, least-cost scenarios are 5-12% cheaper than Business-as-usual scenarios, emit 55-60% less $CO_2$ and use 55-60% less water. Regardless of scenario, results show a consistent and growing build-out of wind capacity to 2050 in South Africa revealing that it is cost-optimal to deploy wind capacity at the rate of at least 0.8-1.0 GW/yr to 2030 and 3-4 GW/yr therafter to 2050.

*Keywords:* South Africa, least-cost, electricity sector, capacity expansion planning,
renewable energy, wind.

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**Highlights**

This research shows that any new-build generation capacity in South Africa should include wind generation capacity. The long-term capacity expansion planning undertaken shows a consistent and growing deployment of wind in South Africa primarily as a result of favourable economics, a world-class wind resource and large geographical land area.

## 1. Introduction

South Africa's electricity sector has been predominantly based on coal-fired supply capacity as a result of the advantageous economics of the technology and significant domestic coal resource. The use of this resource may become limited in future as South Africa has made commitments to slowing down and reducing $CO_2$ emissions with a specific focus on the large contributions made by the use of coal in the electricity sector. Combining this with the planned decommissioning of existing coal generation capacity, an expected increase in future electricity demand and the considerable wind (and solar) resource available (as well as technology cost reductions already realised and expected in future); South Africa has the opportunity to deploy economically competitive wind (and solar) generation capacity into the future.

This paper presents the quantification of this opportunity with a specific focus on wind deployment for a range of scenarios. It presents some background on the existing global wind market, the South African electricity sector (with a focus on wind) followed by an outline of the defined scenarios, approach taken as part of a capacity expansion planning exercise and the data assumptions that inform these. Results from these scenarios are then presented along with a discussion on the implications of the outcomes specifically for wind generation in South Africa followed by conclusions for the research undertaken.

### *1.1. Global wind market*

As shown in Figure 1 and Figure 2, the global wind market has been historically driven by China, U.S.A. and Europe [1]. In 2016, 54 GW of wind capacity was installed across the globe (South Africa installed 0.4 GW of new wind capacity in 2016 - <1% of the global market). Of this new installed capacity, China installed >40% of the 54 GW installed in 2016 with the next closest countries being the U.S.A. (8.2 GW), Germany (5.4 GW) and India (3.6 GW). Total global operational wind capacity at the end of 2016 was 487 GW. This is dominated by China and the U.S.A with 169 GW and 82 GW respectively followed by a number of European countries like Germany (50 GW), Spain (23 GW), U.K. (14 GW) and France (12 GW) while India (29 GW) and Brazil (11 GW) also have large deployments of wind capacity. Wind capacity globally has grown in excess of 20% annually since 2000 and is likely to continue in future resulting in wind generation playing a significant role in a number of countries globally in addition to those already listed.

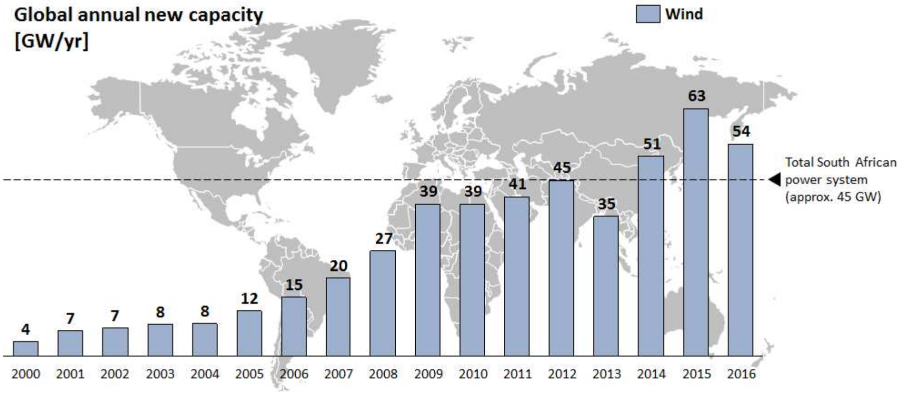


Figure 1: Global wind annual capacity additions (2000-2016) showing scale of wind deployment annually relative to total South African power system.

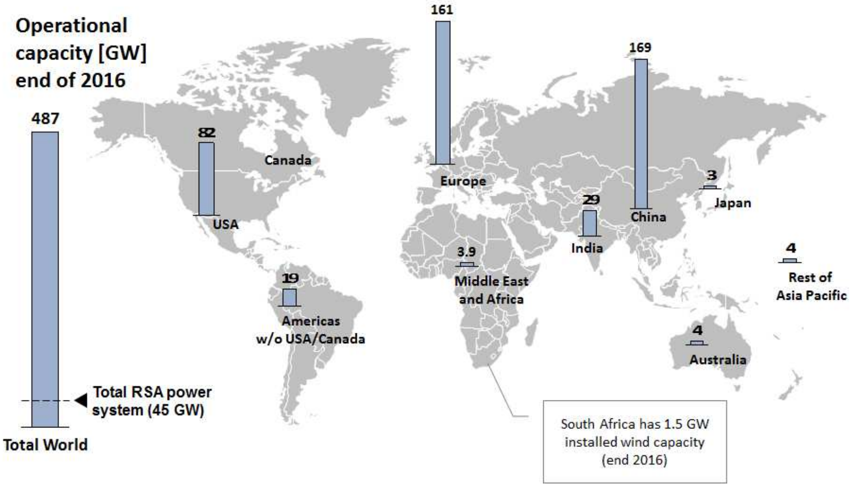


Figure 2: Total global wind capacity operational (2000-2016) showing deployment has been mainly driven by China, U.S.A. and Europe.

## *1.2. South African context*

### *1.2.1. Existing electricity mix*

South Africa's installed capacity and electrical energy mix is summarised by resource type in Table 1 (for 2016) [2, 3, 4]. The South African electricity mix is currently dominated by coal-fired generation capacity complemented by minor nuclear as well as domestic and imported hydro generation capacity (and pumped storage). A small amount of peaking capacity (in the form of open-cycle gas turbines (OCGTs)) also exists which predominantly run on diesel fuel. As will be discussed later, existing coal-fired generation capacity is planned to decommission from the mid 2020s until the mid 2040s.

Table 1: South Africa electricity supply summary by technology (adapted).

| **Technology** | **Installed capacity** | | **Energy (2016)** | |
|---|---|---|---|---|
| | **[GW]** | **[%]** | **[TWh]** | **[%]** |
| Coal | 36.8 | 74% | 194.0 | 82% |
| Nuclear | 1.9 | 4% | 14.3 | 6% |
| Gas | 0.4 | 1% | 0.7 | 0% |
| Peaking[a] | 3.4 | 7% | 2.0 | 1% |
| Hydro[b] + PS[c] | 3.8 | 8% | 18.2 | 8% |
| Wind | 1.5 | 3% | 3.7 | 2% |
| CSP | 0.2 | 0% | 0.5 | 0% |
| Solar PV | 1.5 | 3% | 2.6 | 1% |
| Biomass/-gas[d] | 0.3 | 1% | 1.6 | 1% |
| Battery storage | - | 0% | - | 0% |
| **Total** | **49.6** | **100%** | **237.7**[e] | **100%** |

[a] *Open-cycle gas turbines (OCGTs) fuelled by diesel.*

[b] *Including hydro imports from Mozambique (HVDC interconnected and dispatched by South African SO).*

[c] *PS = Pumped Storage*

[d] *Includes cogeneration.*

[e] *Total = domestic demand + exports*

### *1.2.2. Renewable energy in South Africa (wind focus)*

As an outcome of the South African Integrated Resource Plan (IRP) and resulting Ministerial Determinations from the Department of Energy (DoE), a competitive auction known as the renewable energy independent power producer procurement programme (REIPPPP) for a range of renewable energy (RE) technologies including solar photovoltaics (PV), onshore wind, concentrating solar power (CSP), mini-hydro, landfill-gas, biomass and biogas began in 2011 [5]. As can be seen in Figure 3, the dominant technologies in the REIPPPP have been solar PV, wind and CSP. Large tariff reductions have also been realised (Figure 4 [6]) where over the short period of 4 years, average tariffs for wind reduced by ≈60% while that of solar PV reduced by >80%. Total wind power procured as part of these Bid Windows (BWs) is 4 GW (with another 100 MW of wind capacity not part of the REIPPPP but also operational at the Eskom owned Sere wind farm). Installed capacity and energy from wind, solar PV and CSP up to the end of 2016 is shown graphically in Figure 5a and 5b respectively.

The procured wind capacity as part of the REIPPPP is predominantly located in the Eastern Cape and Western Cape of South Africa (as shown in Figure 6). At the time of writing, there was 1.5 GW of wind capacity operational (see Figure 5a) [7]. All BW 1 (634 MW), BW 2 (563 MW) and $\approx 20\%$ of BW 3 (163 MW) wind capacity as part of the REIPPPP was operational by mid-2017. An additional 100 MW of wind capacity not part of the REIPPPP is also operational (Sere wind farm).

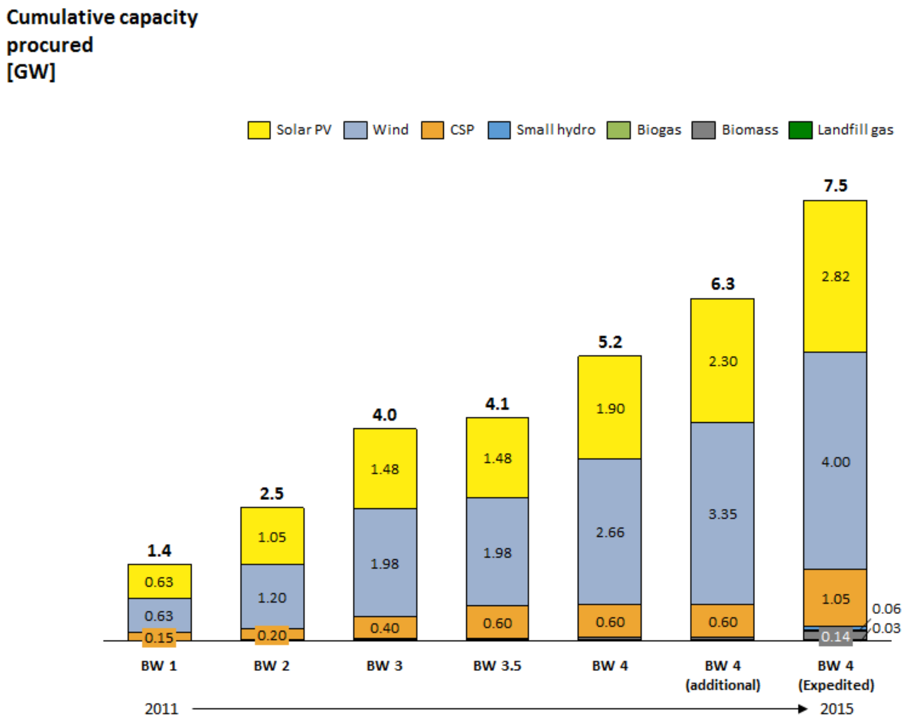


Figure 3: Cumulative capacity procured from first 4 bid windows of South African RE auction process (REIPPPP).

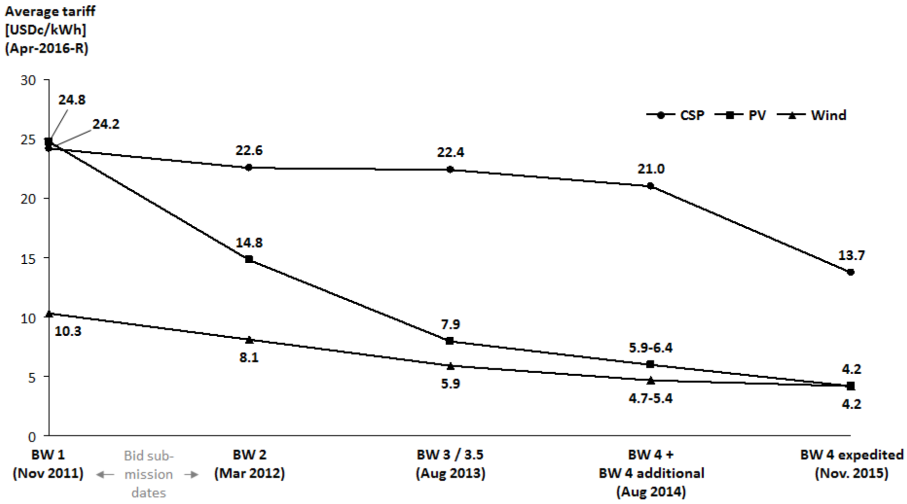
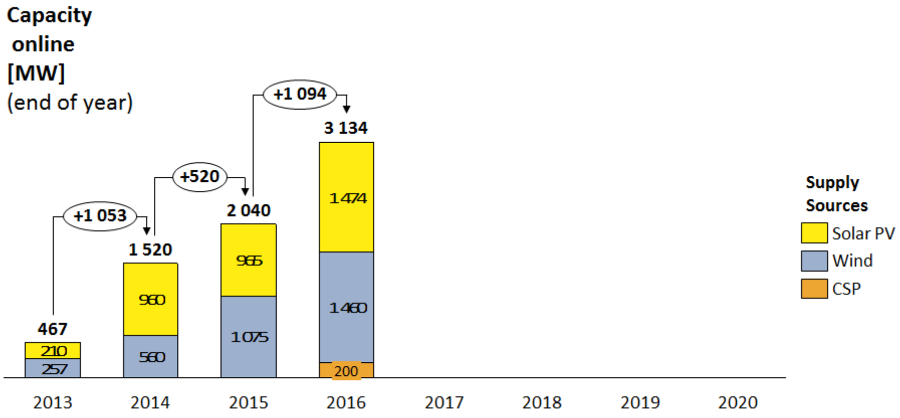
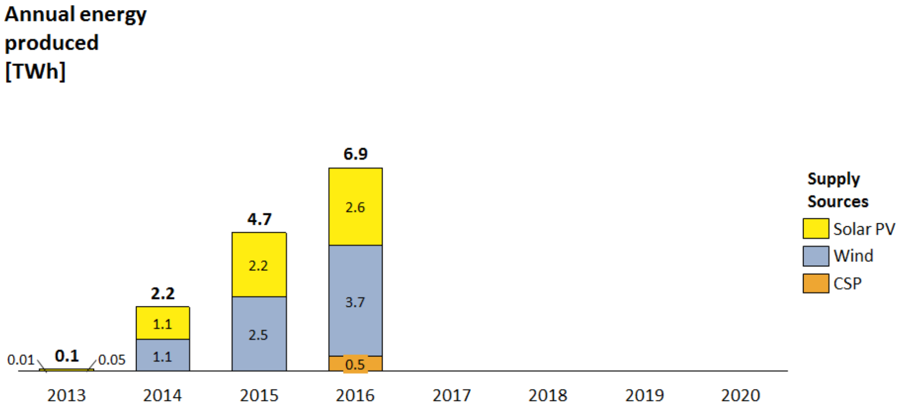


Figure 4: Average tariffs from first 4 bid windows of South African RE auction process (REIPPPP) [6].



(a) Operational capacity.



(b) Energy produced.

Figure 5: Operational renewable energy capacity and energy produced in South Africa (solar PV, wind and CSP to the end of 2016).

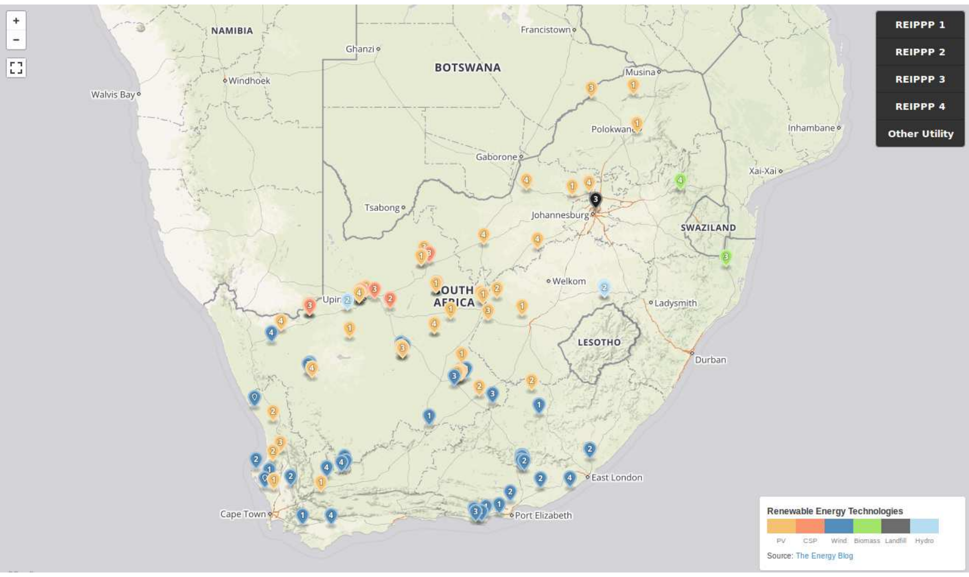


Figure 6: Locations of REIPPPP capacity in South Africa highlighting how wind capacity procured thusfar is predominantly in the Eastern Cape and Western Cape (as expected).

Looking into the future, the overall South African wind resource has recently been quantified in [8] and also summarised in [9] using fundamental data for wind derived from the Wind Atlas of South Africa (WASA) [10] with 5 km x 5 km spatial resolution and 15-minute temporal resolution from 2009-2013. A relative comparison between the global wind resource and that of South Africa can be made by comparing the well known geographical map from [11] and the recently developed geographical map for South Africa in [8] (presented in Figure 7a and Figure 7b respectively). Almost all areas of South Africa have average wind speeds at 100 m above ground $>$6 m/s it is clear that South Africa is well endowed with significant wind resources over a large land area that has not yet been exploited. As an illustration of this, it was shown in [8, 9] that $\approx$70% of South Africa's land area has sufficient wind resource for an annual load factor of 35% or more. Added to this is the relatively low annual seasonality of wind in South Africa.

From another perspective, to produce equivalent energy to South Africa's electrical system load with wind would require $\approx$7 200 km$^2$ of land (0.6% of South Africa's land area)[1] [8] . For some further insight, it was also shown in [8] that for just the Renewable Energy Development

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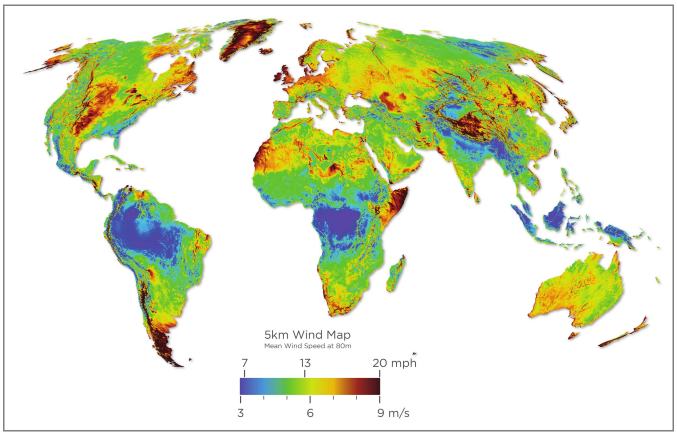
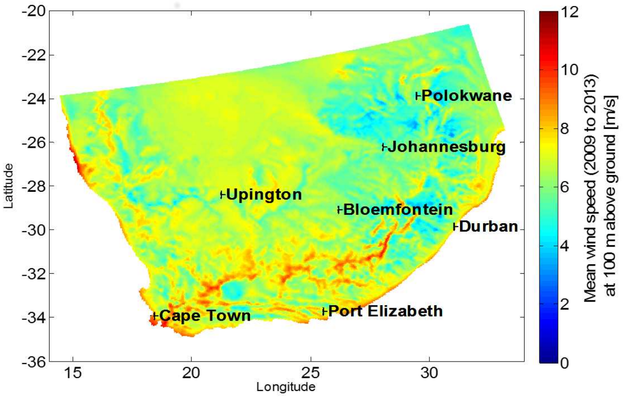
[1] Assuming 0.1 km$^2$/MW

Zones (REDZ)) [12] (areas where renewable energy development has been formally prioritised, ≈7% of South Africa's land area), there is 535 GW/1 780 TWh of wind available. A relative comparison to South Africa's existing electrical system load reveals the scale of the wind resource available. The wind resource just in these REDZ amounts to >7x the existing electrical system load.

From a technical resource potential perspective there is effectively no limitation to wind (or solar PV) in South Africa considering the significant resource and large land area that is available.



(a) Global wind speed at 80 m above ground (© Vaisala 2015).



(b) South Africa wind speed at 100 m above ground (from [8]).

Figure 7: Global wind speed relative to South Africa.

### *1.2.3. Capacity expansion planning in South Africa*

The IRP in South Africa informs the future expansion of the South African electricity sector. It is established by the Electricity Regulation Act No. 4 of 2006 [13] combined with the Electricity Regulations for New Generation Capacity published in 2009 [14]. The South African DoE is the custodian of the IRP and combined with the South African system operator and National Energy Regulator of South Africa (Nersa) are responsible for the development of the IRP as a plan for the electricity sector at the national level. The IRP broadly includes input planning assumptions (on the supply and demand side), a modelling process and scenario planning following which a base plan is derived from the least-cost generation investment requirements with the inclusion of all primary costs within the electricity sector.

The IRP is expected to be updated periodically to ensure generation capacity investments are made on an informed basis considering the latest trends and developments both domestically and internationally in supply technology costs, demand forecasts for electricity and existing generation fleet performance. A key outcome of the IRP is the identification of new generation capacity required (by technology) and the timing associated with these investments. It is well-known and accepted that adjustments are made during this process based on the most probable scenarios as well as government policy objectives including renewable and alternative energies, demand side management and energy efficiency [14]. Following this process, the IRP is approved by the Minister of Energy in the DoE 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 8 while the scenario based approach taken is shown graphically in Figure 9.

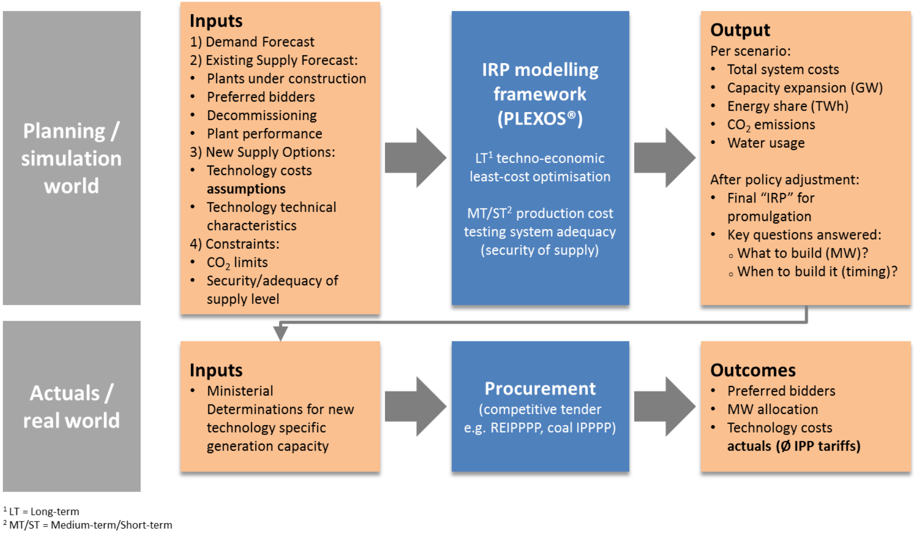
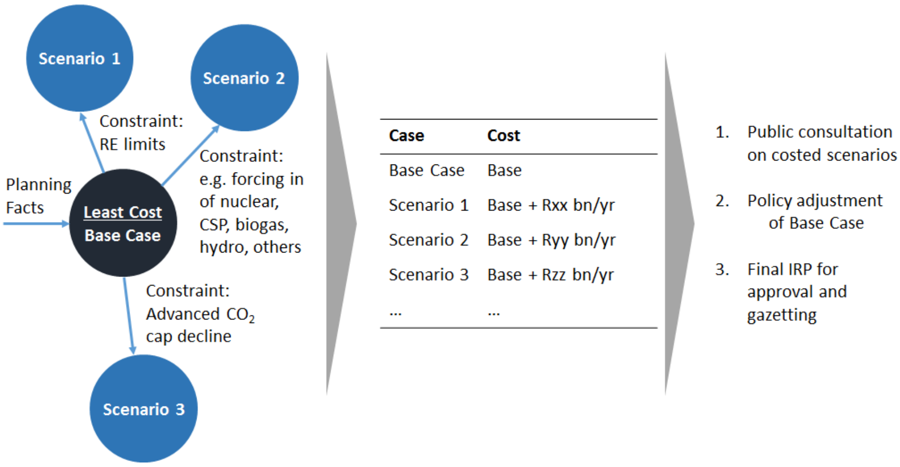


Figure 8: Process of the South African IRP and implementation highlighting how simulation/modelling is translated into implementation of new generation capacity in South Africa.



| Case | Cost |
|---|---|
| Base Case | Base |
| Scenario 1 | Base + Rxx bn/yr |
| Scenario 2 | Base + Ryy bn/yr |
| Scenario 3 | Base + Rzz bn/yr |
| ... | ... |

1. Public consultation on costed scenarios
2. Policy adjustment of Base Case
3. Final IRP for approval and gazetting

Figure 9: Scenario based planning as adopted in the South African IRP.

## 2. Approach

As graphically illustrated in Figure 10, the capacity expansion planning problem is solved using a least cost optimisation with a time horizon to 2050 focussed on generation capacity. The problem is solved using Mixed-Integer Linear Programming (MILP) by co-optimising energy and reserve requirements over the time horizon including existing generators (which decommission over time), committed/under construction generators and new technology investments while ensuring the energy balance is maintained in the least cost manner (subject to adequacy requirements i.e. reserves and the definition of Value of Lost Load (VoLL) metric). The VoLL is set to 5250 \$/MWh while reserve requirements are defined as the sum of Instantaneous, Regulating, 10-Minute, Supplemental and Emergency reserves. These system adequacy requirements are applied for all scenarios considered.

The optimisation is also subject to a number of other user-defined constraints e.g. supply technology technical characteristics (ramp rates, minimum stable levels), supply technology reliability level (Forced Outage Rate (FOR) and Unforced Outage Rate (UFOR)), $CO_2$ emission trajectories and other operational limitations (pumped storage weekly recycling targets and technology specific annual energy constraints (hydro)).

Wind and solar PV generators are assumed to be driven by defined profiles taken from datasets developed in [8] with these profiles being based on the 27 supply areas in South Africa and aggregated into one solar PV and one wind profile respectively to represent existing and expansion candidates for solar PV and wind.

A chronological demand model is applied using a fitted approach with 12 periods per day where the chronology of the demand profile is maintained but intervals are combined together to simplify the problem size. The typical Load Duration Curve (LDC) approach is not utilised as a result of the variability on the supply side from non-dispatchable technologies like solar PV and wind as well as the lack of correlation between these and demand. This approach (along with other similar approaches) is becoming increasingly common amongst energy planners around the world especially in high penetration RE scenarios [15, 16, 17, 18, 19, 20].

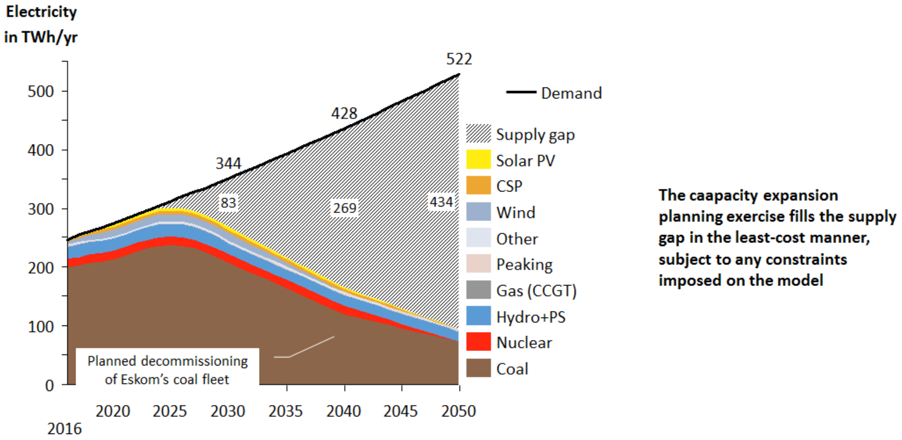


Figure 10: Illustration of the capacity expansion planning problem applied to South Africa (opening supply gap is met by least cost mix of available existing and new resources).

## 3. Scenarios

The scenarios considered as part of this research are summarised in Table 2. These scenarios are based on the latest Draft of the IRP 2016 [21] and the research performed in [22, 23]. Key differences between the scenarios are highlighted in Table 2 and as can be seen the pertinent differences are that of technology costs for wind and solar PV as well annual annual build-out limits on solar PV and wind in the Business as Usual scenarios

Table 2: Scenario summary

| Reference | Scenario name | Demand | Constraints | Technology costs |
|---|---|---|---|---|
| BAU-Hi | Business as Usual | High (Fig. 14) | PPD Moderate (Fig. 15);<br>Annual RE limit* | Tab. A.3-A.5 |
| LC-Hi | Least-cost | High (Fig. 14) | PPD Moderate (Fig. 15) | Tab. A.6-A.8 |
| DC-Hi | Decarbonised | High (Fig. 14) | Decarbonised (Fig. 15) | Tab. A.6-A.8 |
| BAU-Lo | Business as Usual | Low (Fig. 14) | PPD Moderate (Fig. 15);<br>Annual RE limit* | Tab. A.3-A.5 |
| LC-Lo | Least-cost | Low (Fig. 14) | PPD Moderate (Fig. 15) | Tab. A.6-A.8 |

* Annual limit on new-build wind (1.8 GW) and solar PV (1 GW).

## 4. Data assumptions

Pertinent input assumptions are summarised in Appendix A. Input assumptions can be categorised into supply technologies (cost structures and technical characteristics), stationary storage costs, existing generators' decommissioning schedule and performance, system reserve requirements, electrical energy demand forecast, electricity sector $CO_2$ emissions trajectories, demand shaping resources (electric water heaters (EWHs)). These input assumptions are outlined in the sub-sections that follow. A social discount rate of 8.2% is used for all scenarios based on [21].

### *4.1. Supply technology cost structures and technical characteristics*

Cost structures of all technologies are included in Appendix A with key parameters being overnight capital costs, construction time, capital phasing schedule, Fixed Operations and Maintenance (FOM), Variable Operations and Maintenance (VOM), fuel costs and efficiency (heat rate). Key technical constraints include ramp rates, minimum stable levels, start/stop costs, run-up and run-down rates as well as generator minimum up/down times. Wind and solar PV generators are assumed to be driven by defined profiles taken from datasets developed in [8] with wind and solar PV profiles from the 27 supply areas in South Africa aggregated into one solar PV and one wind profile respectively.

### *4.2. Decommissioning schedule*

Existing generation capacity is assumed to decommission as shown in Figure 11 (based on [21]). Existing coal generation capacity decommissions 9.6 GW by 2030, 24.4 GW by 2040 and 31.4 GW by 2050. Most existing peaking capacity decommissions just before 2040 while the only existing nuclear capacity decommissions in the mid-2040s. In the Decarbonised scenario, the decommissioning schedule is not optimised but instead an estimation of an earlier decommissioning schedule is assumed for the existing coal fleet (see Figure 12). All coal generation capacity from 2030 onwards is assumed to decommission 5 years earlier and one of the two currently under construction large coal plants is not commissioned (≈4.8 GW) while the other (≈4.8 GW) and new coal Independent Power Producers (IPPs) are decommissioned from 2045.

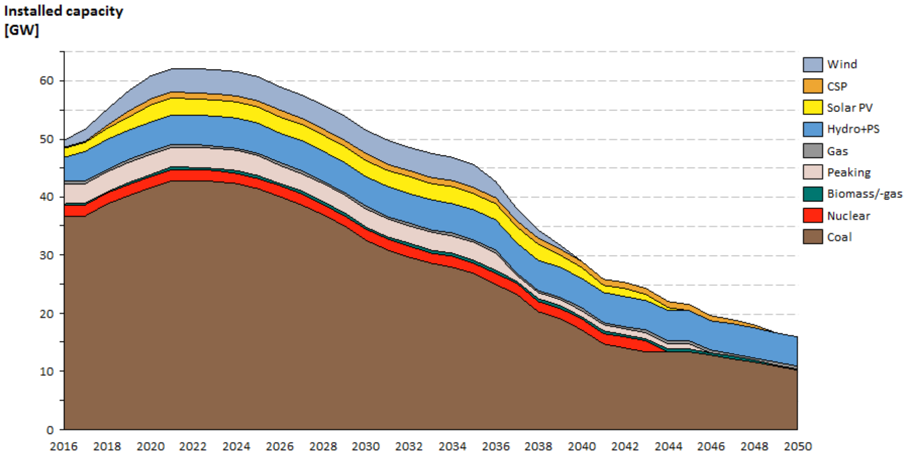


Figure 11: Decommissioning schedule of existing South African generation capacity (2016-2050)

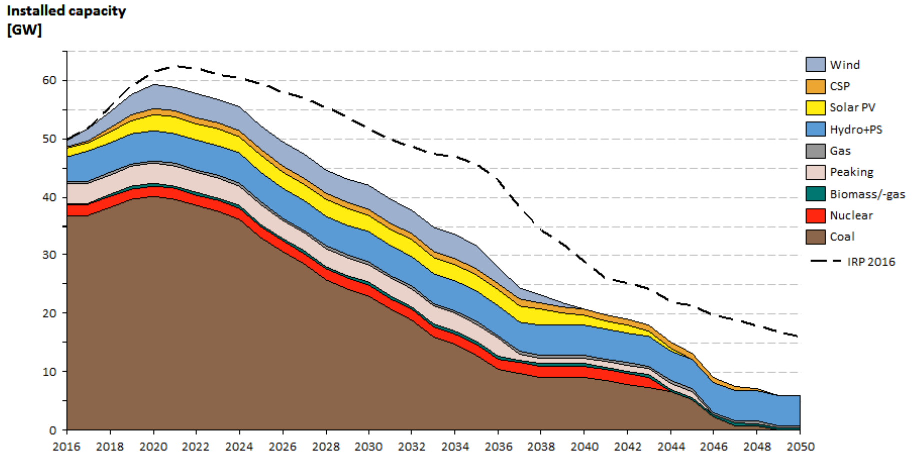


Figure 12: Assumed "Decarbonise" decommissioning schedule of existing South African generation capacity (2016-2050)

### 4.3. Existing coal fleet performance

The existing fleet of power generators in South Africa is predominantly made up of coal capacity whose expected performance is summarised in Figure 13 via the Energy Availability Factor (EAF). Of the three fleet performance profiles shown, the scenarios in this research assume Moderate fleet performance.

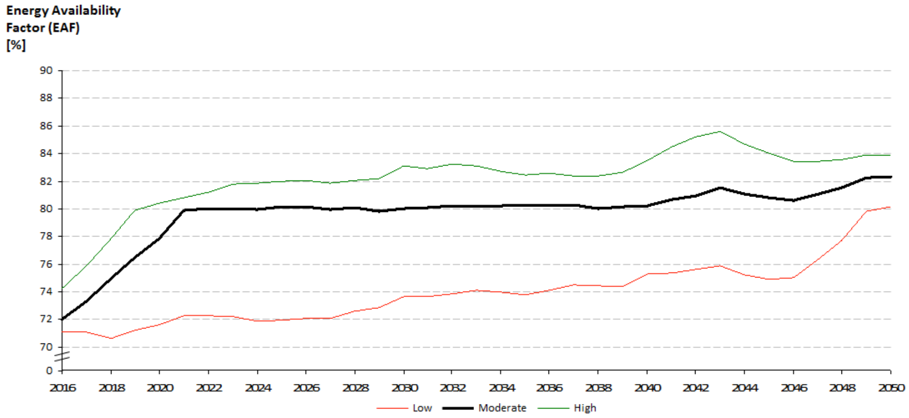


Figure 13: Existing coal fleet performance (2016-2050).

### *4.4. Reserve requirements*

Assumptions on reserve requirements are summarised in Appendix A. Without any additional information (or detailed investigations at this stage), reserve requirements are based on the information presented in [24]. From 2022 onwards, assumptions are based on the rules applied in [24] for Instantaneous, Regulating and 10-Minute reserve categories as far as possible. The largest multiple contingency is initially ≈2000 MW (3 x 669 MW) but then becomes ≈2200 MW once larger coal units are commissioned i.e. 3 x 722 MW from 2018. Looking further into the future, the ”worst case” assumption for a multiple contingency event is two large coal units and one new nuclear unit i.e. ≈3400 MW. The regulating reserve requirement scales linearly with demand into the future and the 10-Minute reserve requirement is still calculated to be the difference between the multiple contingency event, Instantaneous and Regulating reserve requirements (as defined in [24]). The sum of Instantaneous, Regulating, 10-Minute, Supplemental and Emergency reserves are used for long-term capacity expansion planning reserve requirements while each of these reserve categories are modelled explicitly for unit-commitment and economic dispatch runs.

### *4.5. Electrical energy demand forecast*

Figure 14 shows the historical electrical energy demand for South Africa [3] along with the expected high and low demand trajectories from [25]. Electrical energy demand is expected to just more than double in size by 2050 in the high demand forecast while the power system is expected to be in 1.6x bigger in the low demand forecast.

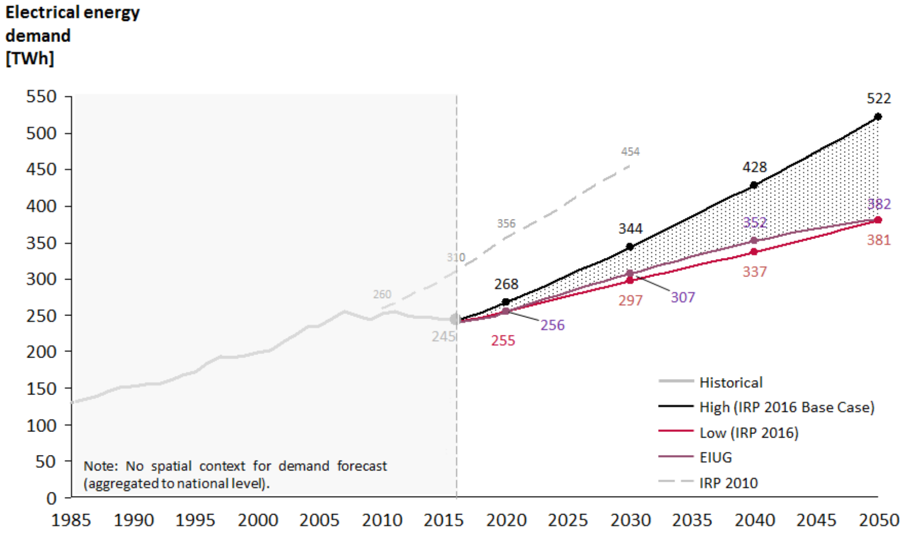


Figure 14: Electrical energy demand forecast assumed for South Africa (historical from [3] and forecast from [25]).

### 4.6. *$CO_2$ emissions trajectories*

Electricity sector $CO_2$ emissions are assumed to follow either the well-known Peak-Plateau-Decline (PPD) trajectory with a Moderate Decline [21] or a Decarbonised trajectory [22, 23]. In the Moderate Decline, $CO_2$ emissions decline from 2037 onwards (from 275 Mt/year to 210 Mt/year in 2050) while in the Decarbonised scenario a linear decline from 2020 onwards to a 95% reduction by 2050 is assumed.

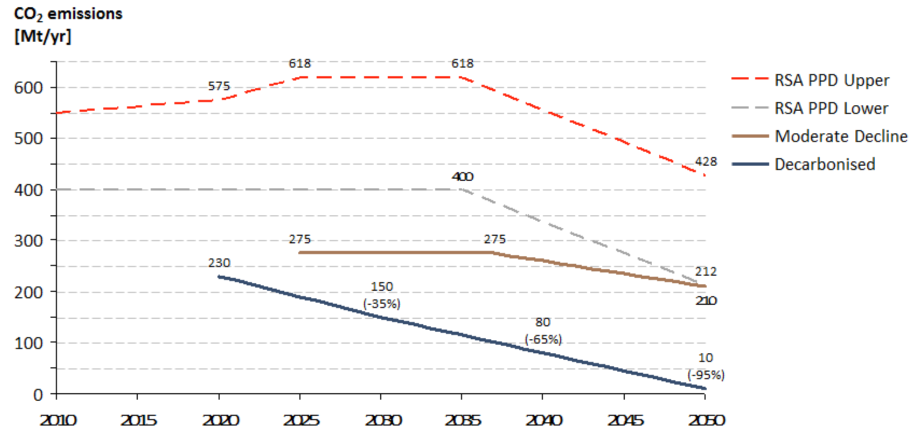


Figure 15: Electricity sector $CO_2$ emissions trajectory for the Moderate Decline and Decarbonise scenarios (shown along with overall PPD trajectories.

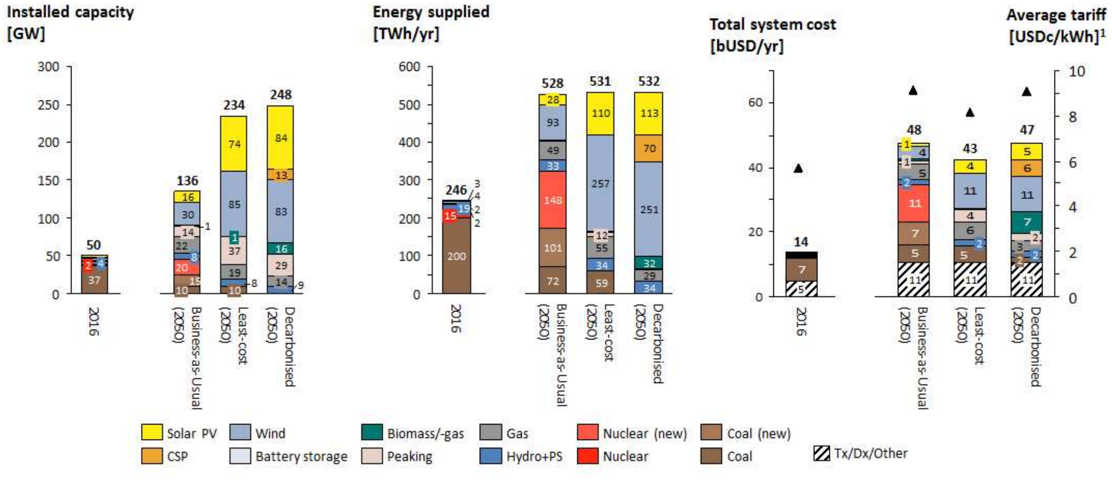
### 4.7. *Demand shaping*

In order to demonstrate the effect of demand shaping, one opportunity has been identified and included in the Least-Cost and Decarbonised scenarios - the intra-day control of residential electric water heater (EWH) demand. This has been investigated and reviewed for a range of end-use appliances in [26, 27] but specifically for EWH in [28, 29, 30] (amongst others). A summary of key parameters which define the EWH resource are given in Appendix A.

## 5. Results and Discussion

Results from the defined scenarios are summarised in Figure 16 and 17 for high and low demand trajectories respectively. The $CO_2$ emissions and water usage by 2050 are summarised in Figure 18. Detailed results for all scenarios considered are included in Appendix B.

In the BAU scenarios, new-build solar PV and wind are built up to the annual new-build limit combined with new-build coal and gas-fired generation capacity. Once the $CO_2$ emission constraint becomes binding, the model chooses to build nuclear capacity and continues to invest in solar PV and wind combined with gas-fired generation. In the BAU scenarios, there is 11 GW of wind capacity by 2030, 21 GW by 2040 and 30 GW by 2050. In the least-cost scenarios where no new-build-limits are imposed on solar PV and wind and updated technology cost assumptions are applied, the optimal new-build configuration is predominantly composed of wind, solar PV



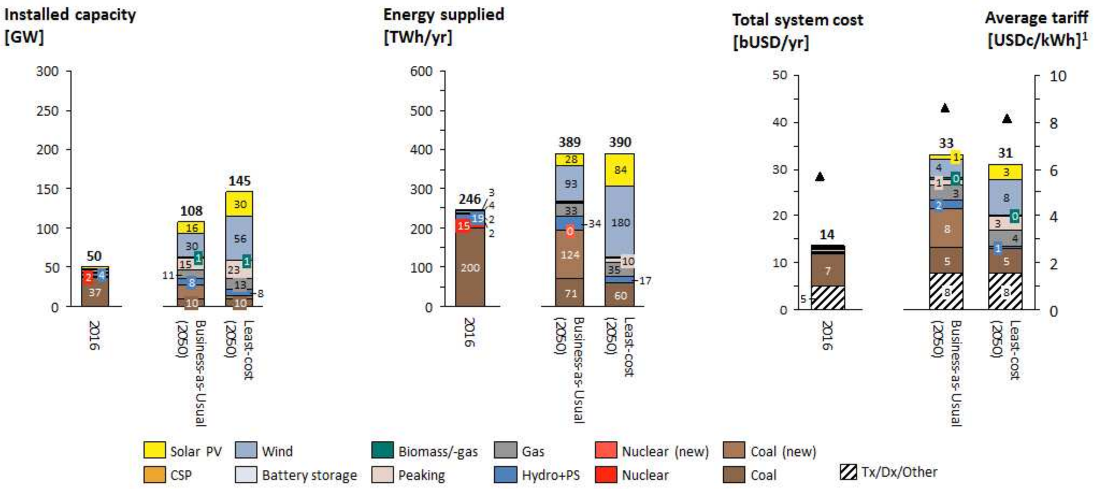
¹ Includes an assumed 2 USDc/kWh (0.30 R/kWh) for transmission, distribution and customer services

Figure 16: Summary of results from scenarios considered for high demand trajectory (BAU-Hi, LC-Hi, DC-Hi) by the end of the 2050 time horizon (installed capacity, energy supplied, total system costs and estimated average tariff).

and flexible natural gas fired generation. In the Least-cost scenarios, there is ≈15-25 GW of installed wind capacity by 2030, ≈40-60 GW by 2040 and ≈60-85 GW by 2050. The Decarbonised scenario is very similar to the Least-cost scenario with the fundamental difference being that between 2040-2050 the $CO_2$ emissions constraint necessitates the building other $CO_2$ free flexible but more expensive dispatchable capacity not chosen in the Least-cost scenario i.e. biomass/-gas and CSP.

By 2050, the LC-Hi scenario is 5.1-bUSD/yr (12%) cheaper than BAU-Hi and 5.0 bUSD/yr (10%) cheaper than DC-Hi. For the low demand trajectory, LC-Lo is 1.9-bUSD/yr (5%) cheaper than BAU-Lo. The average tariff ranges from 8-8.3 USDc/kWh in the LC scenarios and is ≈9.1 USDc/kWh in the BAU scenarios while the Decarbonised is also ≈9.1 USDc/kWh.

Although not the focus of this work, $CO_2$ emissions and water usage summarised in Figure 18 show a considerable difference in expected $CO_2$ emissions from the scenarios considered. The BAU scenarios emit the most $CO_2$ as a result of the considerable new-build coal capacity in these scenarios. The Least-cost scenarios emit ≈55-60% less $CO_2$ than the BAU scenarios while the Decarbonised emits the least $CO_2$ (as expected) at 95% less than BAU and 90% less than LC at 10 Mt/yr by 2050. The Least-cost scenarios also use ≈60-70% less water than Business-as-usual scenarios by 2050.



[1] Includes an assumed 2 USDc/kWh (0.30 R/kWh) for transmission, distribution and customer services

Figure 17: Summary of results from scenarios considered for low demand trajectory (BAU-Lo, LC-Lo) by the end of the 2050 time horizon (installed capacity, energy supplied, total system costs and estimated average tariff).

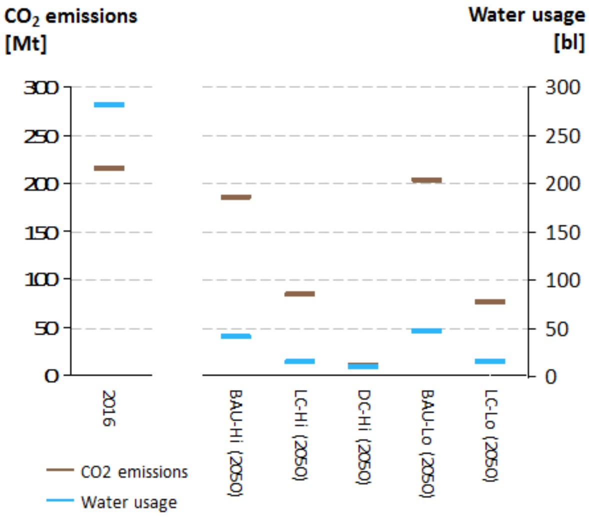
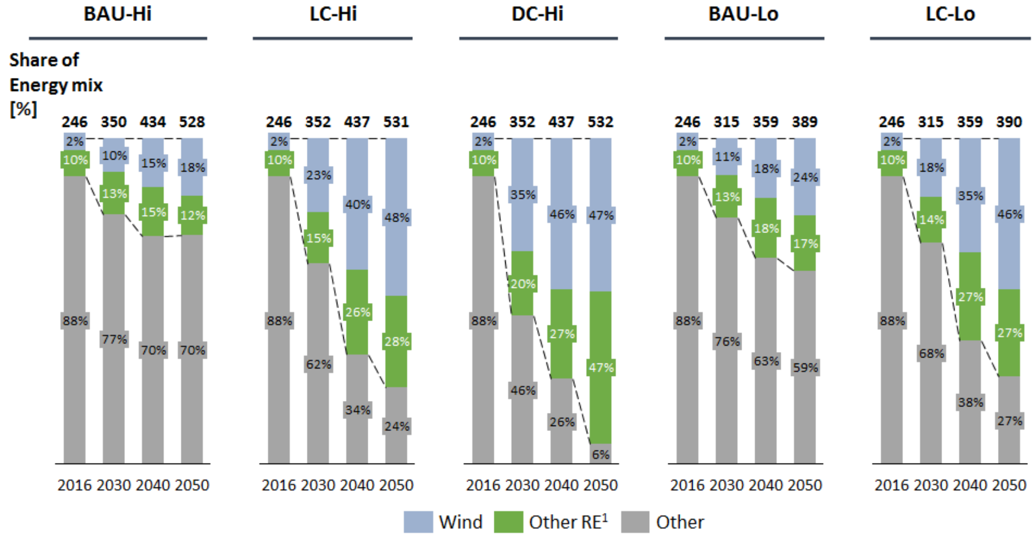


Figure 18: Summary of $CO_2$ emissions and water usage for all scenarios.



Note: For reference, total energy supplied is shown for each year;
¹ Other RE includes domestic and imported renewable energy.

Figure 19: Share of wind and renewable energy from scenarios considered (2016-2050).

The relative contribution of wind (and other RE) to the South African energy mix for all scenarios is shown in Figure 19. With high demand trajectory in the BAU scenario, wind only contributes 10% to the energy mix by 2030 and 18% by 2050. For the low demand trajectory, wind contributes 12% by 2030 and doubles to 24% by 2050. The primary reason for this being the annual new-build limits imposed in the BAU scenarios which become binding, resulting in a similar absolute wind deployment but much higher relative contribution in the low demand trajectory. For both high and low demand trajectories, the LC scenarios result in considerable contributions from wind to the South African energy mix at 18-23% by 2030 and just more than doubling to 47-49% by 2050. As expected in the DC scenario, wind contributes significantly to the energy mix earlier (at 35% by 2030). This is considerably higher than the LC scenario (at 23% by 2030 as previously mentioned). By 2050, the contribution from wind is quite similar in the LC and DC scenarios as other $CO_2$ free dispatchable capacity is included in the mix in the DC scenario to adhere to the $CO_2$ emissions constraint and ensure system adequacy.

The annual deployment of wind across all scenarios is summarised as the gross new-build capacity in Figure 20 (along with annual build-out rates). Regardless of scenario, there is a consistent and growing build-out of wind capacity to 2050 in South Africa (albeit with a wide range

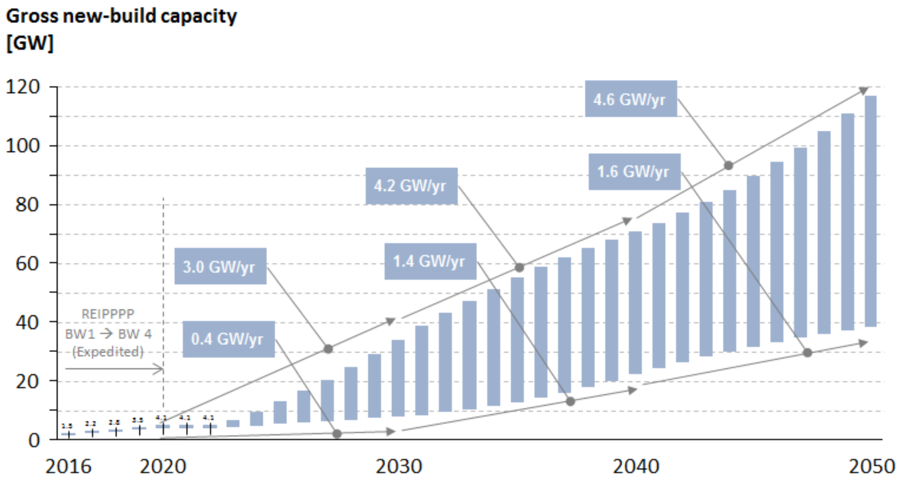


Figure 20: Expected range of gross new-build wind capacity for South Africa (2016-2050) including range of annual build-out rates.

depending on scenario). However, if the Least-cost scenario is considered, there is an average annual build-out rate to 2030 of ≈0.8-1.0 GW/yr and ≈3-4 GW/yr thereafter (regardless of demand trajectory). The Decarbonise scenario requires an even higher deployment at ≈3 GW/yr to 2030 and ≈3.5-4.5 GW/yr thereafter.

This indicates a considerable market for wind development in South Africa in the long-term but should be put into the global market context. The 10-year and 5-year historical annual average global wind capacity deployed has been ≈40 GW and ≈50 GW respectively (summarised in Figure 1 and 2) [1]). This annual deployment of wind globally makes South Africa a relatively small market to 2030 at ≈1.5-2.5% of the historical global wind market per year but likely a medium size market thereafter installing ≈6-10% of historical annual global wind deployed per year. It is appreciated that this assumes similar global wind deployment into the future as has been the case historically (which may not necessarily be the case considering commitments by various countries towards increased deployment of RE and wind specifically) but is a good indication of the relative size of the wind market in South Africa.

## 6. Conclusion

South Africa has historically had a predominantly coal-based energy system and a particularly coal-dominated electricity system. This has been primarily as a result of the availability of a large domestic coal resource as well as favourable economics for coal generation technologies. The more recently well understood world-class wind (and solar) resource in South Africa combined with a large geographical land-area and considerable technology cost reductions globally and domestically for wind and solar PV technologies has made these technologies more than competitive with alternatives. In addition, South Africa's recent commitments made regarding greenhouse gas (GHG) emissions (more particularly $CO_2$ emissions) will mean a constrained deployment of new-build $CO_2$ intensive generation technologies in future (if at all) as the aforementioned economics of alternatives keep improving. As a result, wind (and solar PV) have significant roles to play in the future South African electricity system with recent deployments as part of the REIPPPP an indication of this. The potential role of wind generation capacity in particular is quantified in this research where a least-cost scenario-based electricity sector capacity expansion planning exercise is undertaken. The results of this show that a considerable deployment of wind into the future should be expected where in least-cost scenarios ≈15-25 GW of installed wind capacity by 2030 (≈10-20% of the energy mix), ≈40-60 GW by 2040 (≈20-40% of the energy mix) and ≈60-85 GW by 2050 (≈45-50% of the energy mix) is cost-optimal. By 2050, least-cost scenarios are 5-12% cheaper than Business-as-usual scenarios, emit 55-60% less $CO_2$ and use 55-60% less water. Regardless of scenario, results show a consistent and growing build-out of wind capacity to 2050 in South Africa revealing that it is cost-optimal to deploy wind capacity of at-least 0.8-1.0 GW/yr to 2030 and 3-4 GW/yr therafter to 2050.

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## Abbreviations

| | |
|---|---|
| **BW** | Bid Window |
| **CPI** | Consumer Price Inflation |
| **CCGT** | closed-cycle gas turbine |
| **CSP** | concentrating solar power |
| **DoE** | Department of Energy |
| **EAF** | Energy Availability Factor |
| **EWH** | electric water heater |
| **FOM** | Fixed Operations and Maintenance |
| **FOR** | Forced Outage Rate |
| **GHG** | greenhouse gas |
| **IPP** | Independent Power Producer |
| **IRP** | Integrated Resource Plan |
| **LDC** | Load Duration Curve |
| **MILP** | Mixed-Integer Linear Programming |
| **Nersa** | National Energy Regulator of South Africa |
| **OCGT** | open-cycle gas turbine |
| **PPD** | Peak-Plateau-Decline |

| | |
|---|---|
| **PS** | pumped storage |
| **PV** | photovoltaics |
| **RE** | renewable energy |
| **REDZ** | Renewable Energy Development Zones |
| **REIPPPP** | renewable energy independent power producer procurement programme |
| **UFOR** | Unforced Outage Rate |
| **VoLL** | Value of Lost Load |
| **VoRS** | Value of Reserve Shortfall |
| **VOM** | Variable Operations and Maintenance |
| **WASA** | Wind Atlas of South Africa |

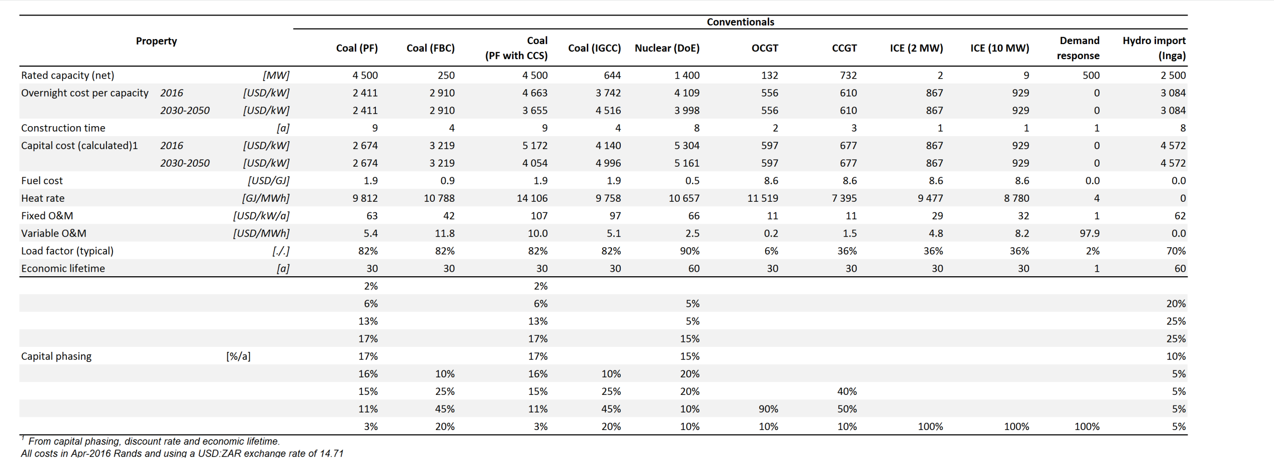
## Appendix A. Input assumptions

Based on [21], Table A.3-A.5 summarise the supply technology input cost assumptions for the Business-as-Usual scenario. Based on [21, 6, 23], Table A.6-A.8 summarise the cost assumptions made for all supply technologies with conservative assumptions made for new supply technologies (solar PV, wind, CSP and stationary storage technologies). All supply technology input cost assumptions are updated to April-2016 Rands using Consumer Price Inflation (CPI) [31]. The 2016 average USD:ZAR exchange rate was 14.71 [32].

Reserve requirements for the scenarios included in this work are summarised in Table A.9.

The key input parameters and associated calculations that define EWHs as a demand shaping resource for demand side flexibility is summarised in Table A.10.

Table A.3: Technology cost input assumptions (conventionals) - Business-as-Usual.



| Property | | | Conventionals | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Coal (PF) | Coal (FBC) | Coal (PF with CCS) | Coal (IGCC) | Nuclear (DoE) | OCGT | CCGT | ICE (2 MW) | ICE (10 MW) | Demand response | Hydro import (Inga) |
| Rated capacity (net) | | *[MW]* | 4 500 | 250 | 4 500 | 644 | 1 400 | 132 | 732 | 2 | 9 | 500 | 2 500 |
| Overnight cost per capacity | *2016* | *[USD/kW]* | 2 411 | 2 910 | 4 663 | 3 742 | 4 109 | 556 | 610 | 867 | 929 | 0 | 3 084 |
| | *2030-2050* | *[USD/kW]* | 2 411 | 2 910 | 3 655 | 4 516 | 3 998 | 556 | 610 | 867 | 929 | 0 | 3 084 |
| Construction time | | *[a]* | 9 | 4 | 9 | 4 | 8 | 2 | 3 | 1 | 1 | 1 | 8 |
| Capital cost (calculated)1 | *2016* | *[USD/kW]* | 2 674 | 3 219 | 5 172 | 4 140 | 5 304 | 597 | 677 | 867 | 929 | 0 | 4 572 |
| | *2030-2050* | *[USD/kW]* | 2 674 | 3 219 | 4 054 | 4 996 | 5 161 | 597 | 677 | 867 | 929 | 0 | 4 572 |
| Fuel cost | | *[USD/GJ]* | 1.9 | 0.9 | 1.9 | 1.9 | 0.5 | 8.6 | 8.6 | 8.6 | 8.6 | 0.0 | 0.0 |
| Heat rate | | *[GJ/MWh]* | 9 812 | 10 788 | 14 106 | 9 758 | 10 657 | 11 519 | 7 395 | 9 477 | 8 780 | 4 | 0 |
| Fixed O&M | | *[USD/kW/a]* | 63 | 42 | 107 | 97 | 66 | 11 | 11 | 29 | 32 | 1 | 62 |
| Variable O&M | | *[USD/MWh]* | 5.4 | 11.8 | 10.0 | 5.1 | 2.5 | 0.2 | 1.5 | 4.8 | 8.2 | 97.9 | 0.0 |
| Load factor (typical) | | *[./.]* | 82% | 82% | 82% | 82% | 90% | 6% | 36% | 36% | 36% | 2% | 70% |
| Economic lifetime | | *[a]* | 30 | 30 | 30 | 30 | 60 | 30 | 30 | 30 | 30 | 1 | 60 |
| | | | 2% | | 2% | | | | | | | | |
| | | | 6% | | 6% | | 5% | | | | | | 20% |
| | | | 13% | | 13% | | 5% | | | | | | 25% |
| | | | 17% | | 17% | | 15% | | | | | | 25% |
| Capital phasing | | [%/a] | 17% | | 17% | | 15% | | | | | | 10% |
| | | | 16% | 10% | 16% | 10% | 20% | | | | | | 5% |
| | | | 15% | 25% | 15% | 25% | 20% | | 40% | | | | 5% |
| | | | 11% | 45% | 11% | 45% | 10% | 90% | 50% | | | | 5% |
| | | | 3% | 20% | 3% | 20% | 10% | 10% | 10% | 100% | 100% | 100% | 5% |

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

*All costs in Apr-2016 Rands and using a USD:ZAR exchange rate of 14.71*

Table A.4: Technology cost input assumptions (renewables) - Business-as-Usual.

| Property | | | Renewables | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | **Wind** | **Solar PV (tracking)** | **Solar PV (fixed)** | **CPV** | **CSP (trough, 3h)** | **CSP (trough, 6h)** | **CSP (trough, 9h)** | **CSP (tower, 3h)** | **CSP (tower, 6h)** | **CSP (tower, 9h)** | **Biomass (forestry)** | **Biomass (MSW)** | **Landfill Gas** | **Biogas** | **Bagasse (Felixton)** | **Bagasse (gen)** |
| Rated capacity (net) | | *[MW]* | 100 | 10 | 10 | 10 | 125 | 125 | 125 | 125 | 125 | 125 | 25 | 25 | 5 | 5 | 49 | 53 |
| Overnight cost per capacity | *2016* | *[USD/kW]* | 1 428 | 1 328 | 1 254 | 3 425 | 5 880 | 7 260 | 8 906 | 5 247 | 6 452 | 7 310 | 5 061 | 9 722 | 2 111 | 5 254 | 1 211 | 2 323 |
| | *2030-2050* | *[USD/kW]* | 1 248 | 1 049 | 998 | 3 425 | 5 880 | 7 260 | 6 187 | 3 622 | 4 467 | 5 079 | 5 061 | 9 722 | 2 111 | 5 254 | 1 211 | 2 323 |
| Construction time | | *[a]* | 4 | 2 | 1 | 1 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 1 | 1 | 2 | 3 |
| Capital cost (calculated)1 | *2016* | *[USD/kW/a]* | 1 471 | 1 339 | 1 254 | 3 425 | 6 505 | 8 031 | 9 852 | 5 805 | 7 138 | 8 086 | 5 599 | 10 754 | 2 111 | 5 254 | 1 244 | 2 419 |
| | *2030-2050* | *[USD/kW/a]* | 1 286 | 1 058 | 998 | 3 425 | 6 505 | 8 031 | 6 845 | 4 007 | 4 941 | 5 618 | 5 599 | 10 754 | 2 111 | 5 254 | 1 244 | 2 419 |
| Fuel cost | | *[USD/GJ]* | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 2.18 | 0.00 | 0.00 | 0.00 | 5.51 | 5.51 |
| Heat rate | | *[GJ/MWh]* | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 243 | 18 991 | 12 302 | 11 999 | 26 874 | 19 327 |
| Fixed O&M | | *[USD/kW/a]* | 41 | 19 | 22 | 21 | 70 | 71 | 73 | 64 | 67 | 69 | 113 | 440 | 161 | 132 | 12 | 26 |
| Variable O&M | | *[USD/MWh]* | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 4.5 | 7.8 | 4.2 | 3.5 | 0.6 | 1.8 |
| Load factor (typical) | | *[./.]* | 36% | 28% | 24% | 30% | 32% | 38% | 46% | 38% | 50% | 60% | 85% | 85% | 85% | 85% | 55% | 50% |
| Economic lifetime | | *[a]* | 20 | 25 | 25 | 25 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| Capital phasing | | *[%/a]* | | | | | | | | | | | | | | | | |
| | | | 5% | | | | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | | | | |
| | | | 5% | | | | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% | | | | 10% |
| | | | 10% | 10% | | | 45% | 45% | 45% | 45% | 45% | 45% | 45% | 45% | | | 33% | 30% |
| | | | 80% | 90% | 100% | 100% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 100% | 100% | 67% | 60% |

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

*All costs in Apr-2016 Rands and using a USD:ZAR exchange rate of 14.71*

Table A.5: Technology cost input assumptions (storage) - Business-as-Usual.

| **Property** | | | **Storage technologies** | | | |
|---|---|---|---|---|---|---|
| | | | **Pumped Storage** | **Battery (Li-Ion, 1h)** | **Battery (Li-Ion, 3h)** | **CAES (8h)** |
| Rated capacity (net) | | *[MW]* | 333 | 3 | 3 | 180 |
| Overnight cost per capacity | *2016* | *[USD/kW]* | 1 518 | 672 | 1 652 | 1 665 |
| | *2030* | *[USD/kW]* | 1 518 | 672 | 1 652 | 1 665 |
| | *2040* | *[USD/kW]* | 1 518 | 672 | 1 652 | 1 665 |
| | *2050* | *[USD/kW]* | 1 518 | 672 | 1 652 | 1 665 |
| Construction time | | *[a]* | 8 | 1 | 1 | 4 |
| Capital cost (calculated)1 | *2016* | *[USD/kW/a]* | 1 893 | 672 | 1 652 | 1 881 |
| | *2030* | *[USD/kW/a]* | 1 893 | 672 | 1 652 | 1 881 |
| | *2040* | *[USD/kW/a]* | 1 893 | 672 | 1 652 | 1 881 |
| | *2050* | *[USD/kW/a]* | 1 893 | 672 | 1 652 | 1 881 |
| Fuel cost | | *[USD/GJ]* | 0.0 | 0.0 | 0.0 | 11.2 |
| Heat rate | | *[GJ/MWh]* | 0 | 4 045 | 4 045 | 4 444 |
| Round-trip efficiency | | *[%]* | | 89% | 89% | 81% |
| Fixed O&M | | *[USD/kW/a]* | 14 | 42 | 42 | 14 |
| Variable O&M | | *[USD/MWh]* | 0.0 | 0.2 | 0.2 | 0.2 |
| Load factor (typical) | | *[./.]* | 33% | 4% | 12% | 22% |
| Economic lifetime | | *[a]* | 50 | 20 | 20 | 40 |
| | | | 1% | | | |
| | | | 1% | | | |
| | | | 2% | | | |
| | | | 9% | | | |
| Capital phasing | | *[%/a]* | 16% | | | |
| | | | 22% | | | 25% |
| | | | 24% | | | 25% |
| | | | 20% | | | 25% |
| | | | 5% | 100% | 100% | 25% |

*All costs in Apr-2016 Rands and using a USD:ZAR exchange rate of 14.71*

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

Table A.6: Technology cost input assumptions (conventionals) - conservative.

| Property | | | Conventionals | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Coal (PF) | Coal (FBC) | Coal (PF with CCS) | Coal (IGCC) | Nuclear (DoE) | OCGT | CCGT | ICE (2 MW) | ICE (10 MW) | Demand response | Hydro import (Inga) |
| Rated capacity (net) | | *[MW]* | 750 | 250 | - | - | 1 400 | 132 | 732 | - | - | - | 2 500 |
| Overnight cost per capacity | *2016* | *[USD/kW]* | 2 411 | 2 910 | - | - | 4 109 | 556 | 610 | - | - | - | 3 084 |
| | *2030-2050* | *[USD/kW]* | 2 411 | 2 910 | - | - | 3 998 | 556 | 610 | - | - | - | 1 |
| Construction time | | *[a]* | 9 | 4 | - | - | 8 | 2 | 3 | - | - | - | 0 |
| Capital cost (calculated)1 | *2016* | *[USD/kW]* | 2 674 | 3 219 | - | - | 5 304 | 597 | 677 | - | - | - | 0 |
| | *2030-2050* | *[USD/kW]* | 2 674 | 3 219 | - | - | 5 161 | 597 | 677 | - | - | - | 0 |
| Fuel cost | | *[USD/GJ]* | 1.9 | 0.9 | - | - | 0.5 | 10.2 | 10.2 | - | - | - | 61.7 |
| Heat rate | | *[GJ/MWh]* | 9 812 | 10 788 | - | - | 10 657 | 11 519 | 7 395 | - | - | - | 0 |
| Fixed O&M | | *[USD/kW/a]* | 63 | 42 | - | - | 66 | 11 | 11 | - | - | - | 0 |
| Variable O&M | | *[USD/MWh]* | 5.4 | 11.8 | - | - | 2.5 | 0.2 | 1.5 | - | - | - | 4.1 |
| Load factor (typical) | | *[./.]* | 82% | 82% | - | - | 90% | 6% | 36% | - | - | - | 0% |
| Economic lifetime | | *[a]* | 30 | 30 | - | - | 60 | 30 | 30 | - | - | - | 0 |
| | | | 2% | - | - | | | | - | - | - | | 0% |
| | | | 6% | - | - | | 5% | | - | - | - | | 0% |
| | | | 13% | - | - | | 5% | | - | - | - | | 0% |
| | | | 17% | - | - | | 15% | | - | - | - | | 0% |
| Capital phasing | | [%/a] | 17% | - | - | | 15% | | - | - | - | | 0% |
| | | | 16% | 10% - | - | | 20% | | - | - | - | | 0% |
| | | | 15% | 25% - | - | | 20% | | 40% - | - | - | | 20% |
| | | | 11% | 45% - | - | | 10% | 90% | 50% - | - | - | | 25% |
| | | | 3% | 20% - | - | | 10% | 10% | 10% - | - | - | | 25% |

[1] *From capital phasing, discount rate and economic lifetime.*
*All costs in Apr-2016 Rands and using a USD:ZAR exchange rate of 14.71*

Table A.7: Technology cost input assumptions (renewables) - conservative.

| Property | | | Renewables | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | **Wind** | **Solar PV (tracking)** | **Solar PV (fixed)** | **CPV** | **CSP (trough, 3h)** | **CSP (trough, 6h)** | **CSP (trough, 9h)** | **CSP (tower, 3h)** | **CSP (tower, 6h)** | **CSP (tower, 9h)** | **Biomass (forestry)** | **Biomass (MSW)** | **Landfill Gas** | **Biogas** | **Bagasse (Felixton)** | **Bagasse (gen)** |
| Rated capacity (net) | | *[MW]* | 100 | - | 10 | - | - | - | - | - | - | 125 | 25 | 25 | 5 | 5 | 49 | 53 |
| Overnight cost per capacity | *2016* | *[USD/kW]* | 901 | - | 628 | - | - | - | - | - | - | 6 340 | 2 984 | 9 722 | 2 111 | 867 | 1 211 | 2 323 |
| | *2030-2050* | *[USD/kW]* | 901 | - | 497 | - | - | - | - | - | - | 3 766 | 2 984 | 9 722 | 2 111 | 867 | 1 211 | 2 323 |
| Construction time | | *[a]* | 4 | - | 1 | - | - | - | - | - | - | 4 | 4 | 4 | 1 | 1 | 2 | 3 |
| Capital cost (calculated)1 | *2016* | *[USD/kW]* | 928 | - | 628 | - | - | - | - | - | - | 7 014 | 3 301 | 10 754 | 2 111 | 867 | 1 244 | 2 419 |
| | *2030-2050* | *[USD/kW]* | 928 | - | 497 | - | - | - | - | - | - | 4 166 | 3 301 | 10 754 | 2 111 | 867 | 1 244 | 2 419 |
| Fuel cost | | *[USD/GJ]* | 0.0 | - | 0.0 | - | - | - | - | - | - | 0.0 | 2.2 | 0.0 | 0.0 | 7.7 | 5.5 | 5.5 |
| Heat rate | | *[GJ/MWh]* | 0 | - | 0 | - | - | - | - | - | - | 0 | 12 386 | 18 991 | 12 302 | 11 999 | 26 874 | 19 327 |
| Fixed O&M | | *[USD/kW/a]* | 34 | - | 14 | - | - | - | - | - | - | 69 | 113 | 440 | 161 | 29 | 12 | 26 |
| Variable O&M | | *[USD/MWh]* | 0 | - | 0 | - | - | - | - | - | - | 0 | 4 | 8 | 4 | 4 | 1 | 2 |
| Load factor (typical) | | *[./.]* | 36% | - | 20% | - | - | - | - | - | - | 60% | 85% | 85% | 85% | 20% | 55% | 50% |
| Economic lifetime | | *[a]* | 20 | - | 25 | - | - | - | - | - | - | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| | | | | | - | - | - | - | - | - | | | | | | | | |
| | | | | | - | - | - | - | - | - | | | | | | | | |
| | | | | | - | - | - | - | - | - | | | | | | | | |
| | | | | | - | - | - | - | - | - | | | | | | | | |
| Capital phasing | | *[%/a]* | | | - | - | - | - | - | - | | | | | | | | |
| | | | 5% | | - | - | - | - | - | - | | 10% | 10% | 10% | | | | |
| | | | 5% | | - | - | - | - | - | - | | 25% | 25% | 25% | | | | 10% |
| | | | 10% | 10% | - | - | - | - | - | - | | 45% | 45% | 45% | | | 33% | 30% |
| | | | 80% | 90% | 100% - | - | - | - | - | - | | 20% | 20% | 20% | 100% | 100% | 67% | 60% |

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

*All costs in Apr-2016 Rands and using a USD:ZAR exchange rate of 14.71*

Table A.8: Technology cost input assumptions (storage) - conservative.

| Property | | | Storage technologies | | | |
|---|---|---|---|---|---|---|
| | | | **Pumped Storage** | **Battery (Li-Ion, 1h)** | **Battery (Li-Ion, 3h)** | **CAES (8h)** |
| Rated capacity (net) | | *[MW]* | 333 | 3 | 3 | 180 |
| Overnight cost per capacity | *2016* | *[USD/kW]* | 1 518 | 672 | 1 652 | 1 665 |
| | *2030* | *[USD/kW]* | 1 518 | 672 | 1 652 | 1 665 |
| | *2040* | *[USD/kW]* | 1 518 | 672 | 1 652 | 1 665 |
| | *2050* | *[USD/kW]* | 1 518 | 672 | 1 652 | 1 665 |
| Construction time | | *[a]* | 8 | 1 | 1 | 4 |
| Capital cost (calculated)[1] | *2016* | *[USD/kW]* | 1 893 | 672 | 1 652 | 1 881 |
| | *2030* | *[USD/kW]* | 1 893 | 672 | 1 652 | 1 881 |
| | *2040* | *[USD/kW]* | 1 893 | 672 | 1 652 | 1 881 |
| | *2050* | *[USD/kW]* | 1 893 | 672 | 1 652 | 1 881 |
| Fuel cost | | *[USD/GJ]* | 0.0 | 0.0 | 0.0 | 11.2 |
| Heat rate | | *[GJ/MWh]* | 0 | 4 045 | 4 045 | 4 444 |
| Round-trip efficiency | | *[%]* | | 89% | 89% | 81% |
| Fixed O&M | | *[USD/kW/a]* | 14 | 42 | 42 | 14 |
| Variable O&M | | *[USD/MWh]* | 0.0 | 0.2 | 0.2 | 0.2 |
| Load factor (typical) | | *[./.]* | 33% | 4% | 12% | 22% |
| Economic lifetime | | *[a]* | 50 | 10 | 10 | 40 |
| Capital phasing | | *[%/a]* | 1% | | | |
| | | | 1% | | | |
| | | | 2% | | | |
| | | | 9% | | | |
| | | | 16% | | | |
| | | | 22% | | | 25% |
| | | | 24% | | | 25% |
| | | | 20% | | | 25% |
| | | | 5% | 100% | 100% | 25% |

*All costs in Apr-2016 Rands and using a USD:ZAR exchange rate of 14.71*

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

Table A.9: Assumed reserve requirements to 2050.

| | | | 2016-2019 | 2020-2022 | 2023-2024 | 2025-2029 | 2030-2034 | 2035-2039 | 2040-2044 | 2045-2049 | 2050-2054 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Instantaneous | Summer | Peak | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| | | Off-peak | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| | Winter | Peak | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| | | Off-peak | 800 | 800 | 800 | 800 | 800 | 800 | 800 | 800 | 800 |
| Regulating | Summer | Peak | 550 | 550 | 570 | 640 | 720 | 800 | 890 | 990 | 1 010 |
| | | Off-peak | 550 | 550 | 570 | 640 | 720 | 800 | 890 | 990 | 1 010 |
| | Winter | Peak | 600 | 600 | 630 | 720 | 820 | 920 | 1 020 | 1 120 | 1 140 |
| | | Off-peak | 600 | 600 | 630 | 720 | 820 | 920 | 1 020 | 1 120 | 1 140 |
| Ten-minute | Summer | Peak | 1 150 | 1 150 | 1 130 | 2 260 | 2 180 | 2 100 | 2 010 | 1 910 | 1 890 |
| | | Off-peak | 850 | 850 | 830 | 1 960 | 1 880 | 1 800 | 1 710 | 1 610 | 1 590 |
| | Winter | Peak | 1 100 | 1 100 | 1 070 | 2 180 | 2 080 | 1 980 | 1 880 | 1 780 | 1 760 |
| | | Off-peak | 800 | 800 | 770 | 1 880 | 1 780 | 1 680 | 1 580 | 1 480 | 1 460 |
| Operating | Summer | Peak | 2 200 | 2 200 | 2 200 | 3 400 | 3 400 | 3 400 | 3 400 | 3 400 | 3 400 |
| | | Off-peak | 2 200 | 2 200 | 2 200 | 3 400 | 3 400 | 3 400 | 3 400 | 3 400 | 3 400 |
| | Winter | Peak | 2 200 | 2 200 | 2 200 | 3 400 | 3 400 | 3 400 | 3 400 | 3 400 | 3 400 |
| | | Off-peak | 2 200 | 2 200 | 2 200 | 3 400 | 3 400 | 3 400 | 3 400 | 3 400 | 3 400 |
| Supplemental | Summer/ Winter | Peak/ Off-peak | 1 300 | 1 300 | 1 300 | 1 300 | 1 300 | 1 300 | 1 300 | 1 300 | 1 300 |
| Emergency | | | 300 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 |
| Total | Summer/ Winter | Peak/ Off-peak | 3 800 | 4 400 | 4 400 | 5 600 | 5 600 | 5 600 | 5 600 | 5 600 | 5 600 |

Table A.10: Input parameters and calculations for 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 |

## Appendix B. Detailed Results

Detailed results for each scenario considered are given in Figure B.21-B.25.

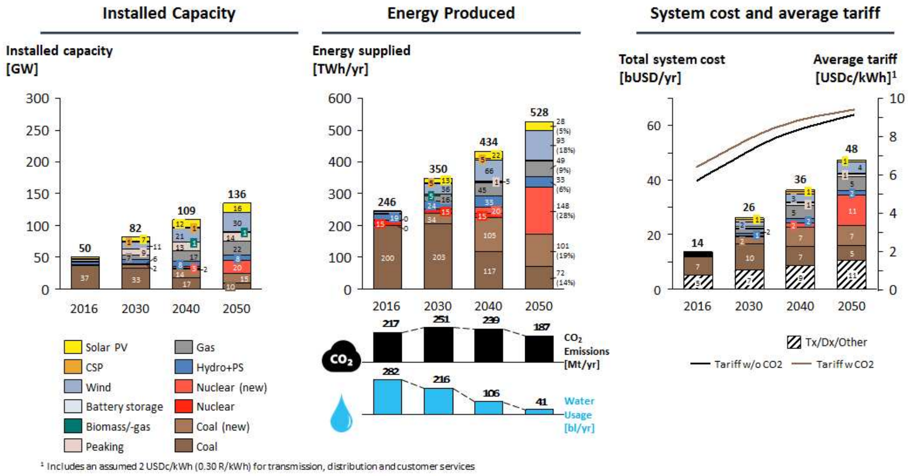


Figure B.21: Detailed results summary for BC-Hi scenario (Base Case - High demand).

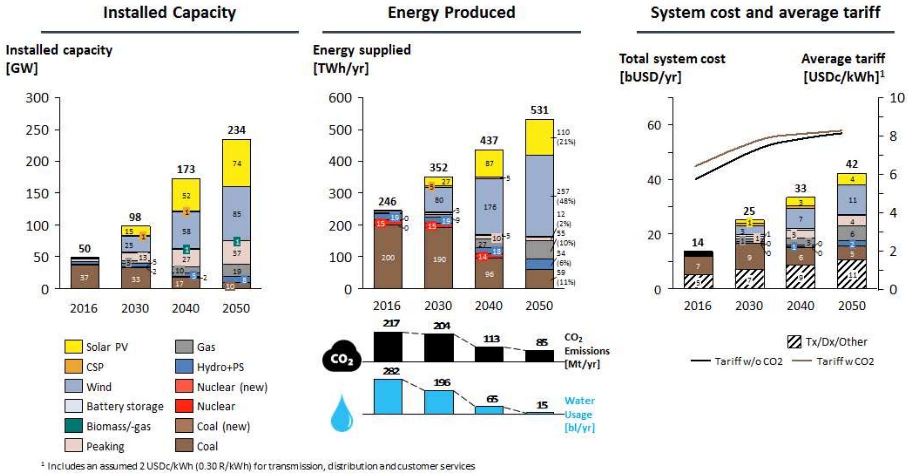
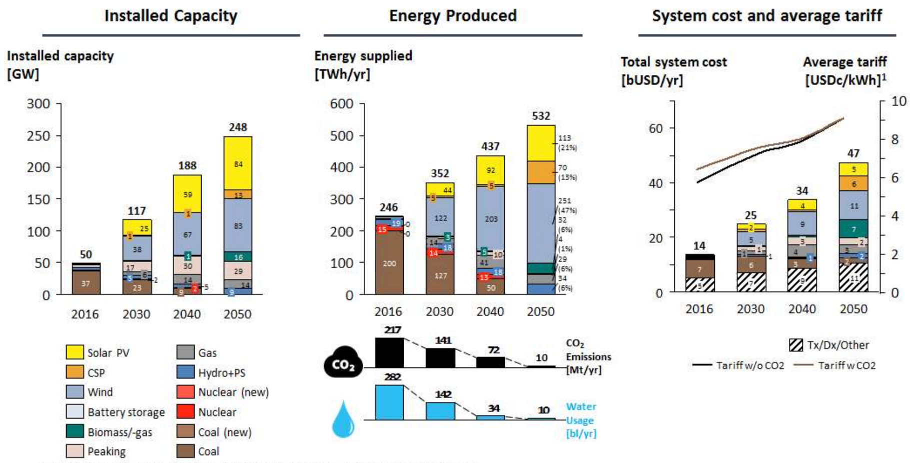
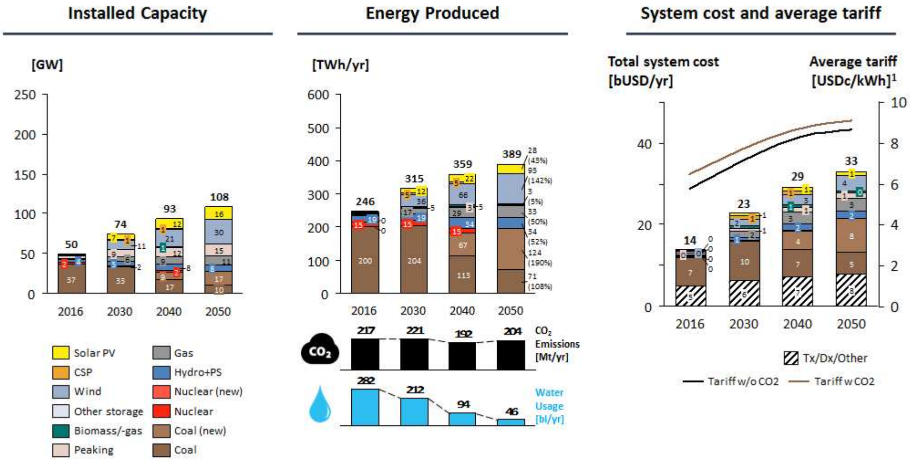


Figure B.22: Detailed results summary for LC-Hi scenario (Least-cost - High demand).



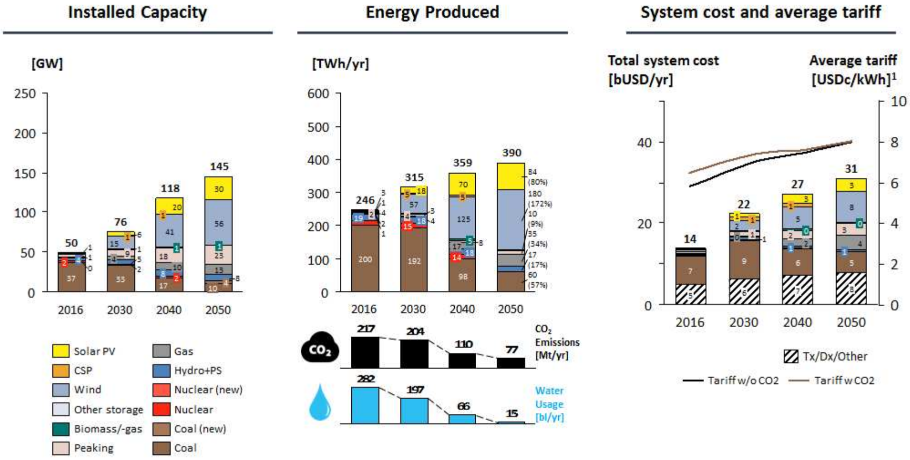
¹ Includes an assumed 2 USDc/kWh (0.30 R/kWh) for transmission, distribution and customer services

Figure B.23: Detailed results summary for DC-Hi scenario (Decarbonise - High demand).



¹ Includes an assumed 2 USDc/kWh (0.30 R/kWh) for transmission, distribution and customer services

Figure B.24: Detailed results summary for BC-Lo scenario (Base Case - Low demand).



¹ Includes an assumed 2 USDc/kWh (0.30 R/kWh) for transmission, distribution and customer services

Figure B.25: Detailed results summary for LC-Lo scenario (Least-cost - Low demand).