Supply and Demand Side Flexibility Options for High Renewable Energy Penetration Levels in South Africa

Peter Klein, Clinton Carter-Brown, Jarrad G. Wright, and Joanne R. Calitz

***Abstract*—This paper presents a study on supply and demand side flexibility resources assessed for two South African power system expansion scenarios with high penetrations of variable renewable energy. The demand response opportunities associated with residential water heating as well as plug-in electric vehicles are included in order to demonstrate demand-side flexibility options. Supply-side options are based on existing and optimally deployed new-build generation technologies. The scenario based results indicate that the combination of cost reductions in wind, solar PV and stationary storage (batteries), results in economic deployment of batteries in South Africa. Battery storage complements flexibility provided by demand response and supply-side options. A notable outcome is the displacement of gas-fired turbines by batteries when assuming cost reductions for batteries in the future. Finally, despite the extensive deployment of battery storage, a significant 55 TWh of energy from solar PV and wind is curtailed. Therefore, effective sector-coupling could make extensive use of this curtailed energy in a number of ways to be identified as part of future research.**

***Index Terms*—Integrated Resource Planning, Energy Sector Coupling, Energy Storage, Demand Response, Electric Vehicles.**

I. Introduction

THE projected growth in South Africa's electricity demand over the next 20 years, coupled with the planned decommissioning of the country's existing generation fleet, will create a supply gap that must be addressed through the construction of new power generation capacity. Long-term capacity expansion planning is required to determine the optimal mix of new-build technologies that should be constructed in order to provide the required system adequacy (energy and reserve provision) at least-cost, while meeting South Africa's commitments to reducing greenhouse-gas emissions.

A comparison of the Levelised Costs of Electricity (LCOE) of different new build generator technologies is presented in Table I. The LCOE for renewable energy generators (concentrating solar power (CSP), solar PV and wind) are based on the latest auction bids that were achieved in November 2015 through the Renewable Energy Power Producer Procurement Programme (REIPPPP). Conventional generator LCOE is based on assumed costs and capacity factors. Due to South Africa's extensive solar and wind resources, coupled with rapidly decreasing technology costs, solar PV and wind are now the least cost generators of bulk electricity with an LCOE of R0.62/kWh (Apr-2016 Rand), which is 38% lower than new build coal generators.

A power grid characterised by an increasing penetration of variable renewable energy (VRE) generators such as solar PV and wind, requires the flexibility of the grid to be improved in order to ensure the matching of instantaneous supply and demand. This grid flexibility can be provided through a number of approaches, including: (1) demand-side management, (2) flexible generation, (3) energy storage (4) sector coupling and (5) grid expansion.

Flexible generation typically needs to be deployed for system level balancing. The LCOE for natural gas fired turbines as a source of flexibility are based on imported Liquefied Natural Gas (LNG) at an assumed cost of R150/GJ, which yields an LCOE of R1.41/kWh for mid-merit CCGTs and R2.89/kWh for peaking OCGTs. Should alternative flexibility technologies, such as battery storage, be available at a lower cost to the power system, these technologies would then offset the need for extensive deployment of gas turbines. It is therefore important to conduct modelling studies to determine the effect of different storage cost projections and sector coupling on the future demand for imported LNG for the power system. The results of such investigations will inform decisions on the scale of investments that should be made into the required gas infrastructure for the power system.

This paper presents a novel investigation into the effect of energy storage costs (Li-ion batteries) on the least cost energy mix for South Africa as well as the demand for natural gas. A high level analysis of opportunities for creating flexible demand through sector coupling is also presented for the case of residential Electric Water Heating (EWH) and Electric Vehicles (EVs).

II. Sector Coupling and Energy Storage

Analysis conducted by Roos [1], based on the greenhouse gas inventory by the Department of Environmental Affairs [2], showed that the electricity sector accounted for 51.6% of South Africa's direct emissions in 2010, whilst transport (8.2%), liquid fuel refineries (9.6%) and industry (12.2%), accounted for a combined 30% of direct greenhouse gas emissions. It is therefore critical to consider decarbonisation of not only the electricity sector, but also other energy end-uses that contribute to emissions such as transportation and heat demand (residential, commercial and industrial).

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TABLE I
LEVELISED COST OF ELECTRICITY (LCOE) FOR NEW BUILD GENERATORS IN SOUTH AFRICA (APR-2016 RAND)

Generator	Capacity Factor [%]	LCOE [R/kWh]
*Renewable Energy Generators**		
Solar PV	26%	0.62
Wind	35%	0.62
CSP	31%	2.02
*Conventional Fossil Fuel Generators***		
Baseload Coal	82%	1.00
Nuclear	90%	1.09
Gas (CCGT)	50%	1.41
Mid-merit Coal	50%	1.41
Gas (OCGT)	10%	2.89
Diesel (OCGT)	10%	3.69

** Capacity factor based on operation plants in 2016. LCOE values in real terms based on PPA's from REIPPPP bids [3].*
*** Changing full-load hours for new-build options drastically changes the fixed cost components per kWh (lower full-load hours = higher capital costs and fixed O&M costs per kWh); Assumptions: Average efficiency for CCGT = 55%, OCGT = 35%; nuclear = 33%; IRP costs from Jan-2012 escalated to May-2016 with CPI; assumed EPC CAPEX inflated by 10% to convert EPC/LCOE into tariff [4];*

Decarbonisation of the electricity sector can be achieved using renewable energy generators (primarily solar and wind), which essentially have an unlimited technical potential due to South Africa's extensive solar and wind resources. The technical potential of biofuels (transport) and biomass (heat demand) are limited by the arable land available. Thus, it is necessary to introduce sector coupling, whereby clean, low cost, electricity is used as an energy carrier for transportation and the supply of thermal energy. The development and optimisation of an integrated energy system can significantly enhance the overall system flexibility [5].

The concept of sector coupling, combined with different forms of energy storage is presented in Figure 1. Energy storage is an extensive topic including a range of different technologies and applications. In Power-to-Power (electricity in/electricity out) energy storage electrical energy is typically converted into either mechanical or chemical energy, which can be stored and later reconverted into electricity when required (capacitors can store electric charge directly). Alternatively excess energy can also be converted into other energy carriers such as gas or liquid fuels (Power-to-Gas/Liquids), as well as thermal energy (Power-to-Heat) for use outside the power sector. Furthermore, the integration of EVs can be used to directly couple electricity to transportation. Sector coupling creates an opportunity for additional value streams to the power sector.

A. *Power-to-Power*

Currently there is a significant global research focus on Power-to-Power energy storage systems. Power-to-Power use cases (applications) can be defined according to four broad categories, namely: Bulk Energy Services, Ancillary Services, Grid Infrastructure Services (transmission and distribution upgrade deferral), and Customer Energy Management Services [6]. Batteries have the potential to fulfil a range of different applications which can be potentially combined (stacked) to increase the number of revenue streams for the storage system. Global demand for battery storage is being driven by electric vehicles, stationary storage, and consumer devices. Lithium-ion batteries in particular can be deployed in a range of stationary and mobile applications.

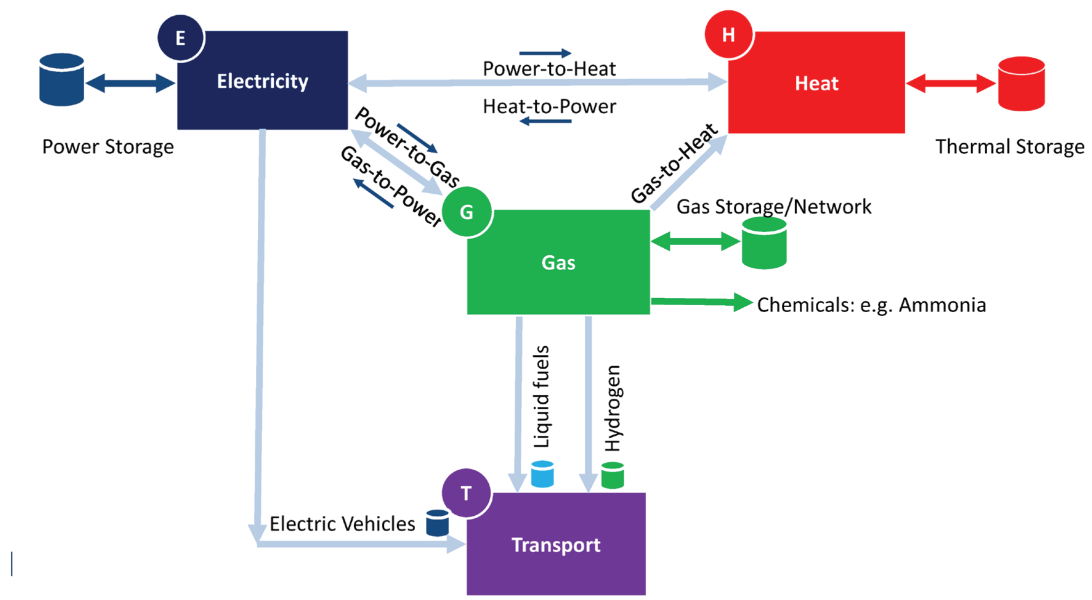

Fig. 1. Sector coupling of electricity, heat and transport, modified from [5]

As shown in Figure 2, research conducted by Bloomberg New Energy Finance (BNEF), shows the the cost of Li-ion battery packs has decreased by 79% between the years of 2010 and 2017. The pack costs for mobile applications include the battery management system, wiring, pack housing and thermal management. These cost reductions have been driven by technology improvements (energy density and pack design), growth in demand leading to improved economies of scale in battery manufacturing, as well as growing competition in the battery market [7]. For stationary battery storage applications BNEF estimate costs could be up to double the mobile pack costs due to inverters, engineering and installation costs. The Electric Power Research Institute (EPRI), estimate that installed system costs of stationary storage can be 2-3 times higher than the battery costs due to auxiliary equipment, installation, operation and maintenance and battery replacement and disposal costs [8].

Lithium-ion batteries are not the only Power-to-Power storage technology exhibiting performance improvements and cost reductions. Flow batteries as well as super-capacitors present credible alternatives to Li-ion if the costs are competitive. In the current paper Li-ion batteries are included in the modelling. However, these are essentially a proxy for any battery/capacitor technology that could be deployed.

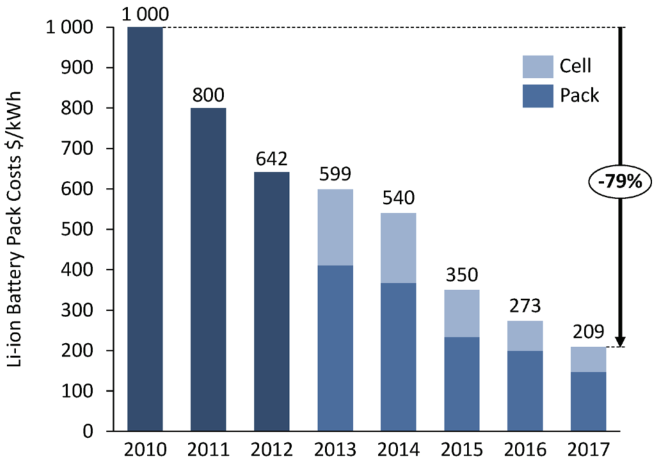

Fig. 2. Cost reductions in Lithium-ion battery packs (the split between cell and pack costs not avilable for 2010-2012) [7]

B. Power-to-Heat and Thermal Storage

Thermal Energy Storage (TES) systems are typically of lower cost (less than \$50/kWh$_t$) and complexity than competing battery storage technologies. TES is suited to energy storage applications where the end-use of the energy is thermal (heat and cold), which includes space heating/cooling, hot water demand, and industrial process heating/cooling. As shown in Figure 3, the Department of Energy estimates that the end-use of energy in the residential, commercial and industrial sectors is predominantly thermal. In the South African residential sector approximately 28% of households currently utilise EWH, coupled with low cost TES in the form of electric geysers [9]. The industrial sector currently makes extensive use of fossil fuels for process heating (coal dominant), which presents an opportunity for decarbonisation through Power-to-Heat conversions. In the commercial sector, electricity is used for HVAC systems, while coal fired boilers are operated numerous public buildings such as hospitals and prisons. One of the challenges to electrifying thermal loads in the industrial and commercial sectors is the low the cost of coal in the order of R900/ton or R0.12/kWh input energy (excluding conversion and distribution efficiency).

TES can be used in a number of applications, including: energy shifting and peak demand reduction (thermal loads), off-grid and waste heat utilisation. Ice/cold water storage is already extensively utilised in a number of commercial buildings to reduce the peak electricity demand due to air-conditioning. Recently Ice Energy was contracted by Southern California Edison in the US to provide 25.6 MW$_t$ of behind the meter ice storage, using the Ice-Bear TES system.

C. Power-to-Gas/Liquids

Through Sasol and PetroSA, South Africa has extensive experience with the production of synthetic fuels via Coal-to-Liquid (CTL) and Gas-to-Liquid (GTL) processes. There are also new opportunities for the export of hydrogen and other fuels such as methanol. As outlined by Roos [1], Japan has indicated the intention to import 9 billion Nm^3 of hydrogen

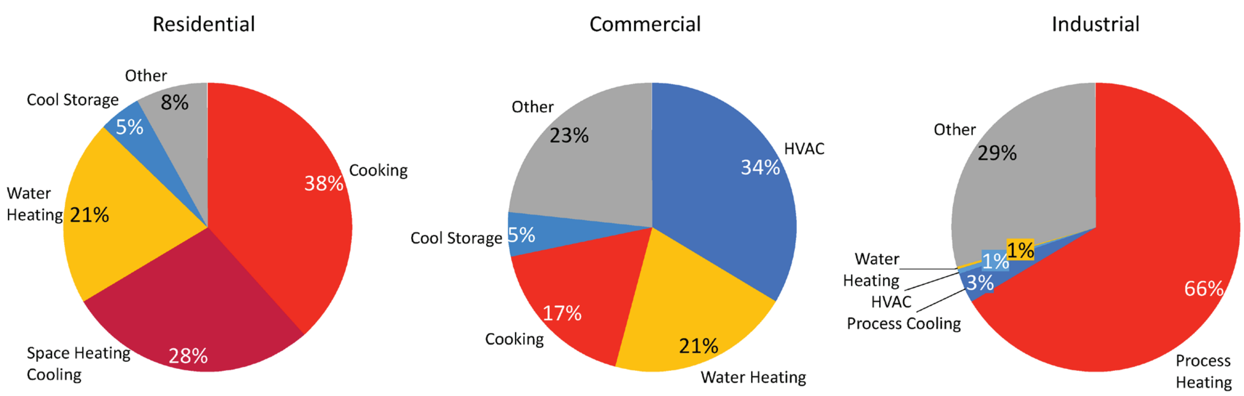

Fig. 3. End-use of energy in the residential, commericial and industrial sectors [10]

(from renewable sources) per year by 2040 at a price of \$3/kg. This equates to a potential export market in the order of R31 billion (2016 coal export market was R47 billion). The EU Renewable Energy Directive (RED) states that 10% of fuel/energy for terrestrial transport should be from renewable sources by 2020. South Africa's significant solar and wind resources, combined with a strong synthetic fuels industry, should position the country to be a competitive exporter of clean fuels through Power-to-Gas/Liquids. South Africa is also in the unique position of having excellent combined solar and wind resources, which has the potential for higher plant capacity factors than a number of other countries.

III. Methodology

The modelling presented is based on a 'Low Demand' growth trajectory from the 2016 Draft Integrated Resource Plan (IRP) for South Africa, where electrical energy demand is projected to grow from 245 TWh p.a. in 2016 to 307 TWh p.a. in 2030 and 381 TWh p.a. in 2050 [4]. Figure 4 presents the supply gap that must be filled due to the combination of demand growth and planned decommissioning of the existing generation fleet up to 2050. The least-cost mix of existing and new build generators is calculated using a Mixed-Integer Linear Programming (MILP) approach that is subject to constraints placed on the model. The MILP apprach is implemented in the software tool PLEXOS to co-optimise the energy and reserve requirements up until 2050. A detailed description of the modelling approach using PLEXOS can be found in [11]-[13] and is summarised in Appendix A.

The electricity system model used for both scenarios includes only the South African power system. The model was configured with hourly temporal resolution and the study horizon was from 2016 to 2050, with results being reported per decade. Transmission constraints were excluded from the implementation i.e. only generation costs were modelled. Broader socio-economic dimensions like existing/new employment opportunities in the energy sector were also excluded from the analysis.

A. Description of Scenarios

Two scenarios are considered in order to assess the impact of different assumed technology costs on the least cost mix of technologies deployed up to 2050. The costs of solar PV, wind and lithium-ion batteries are varied between the two scenarios, while the costs for all other supply technologies are kept equal for both scenarios, as given in Appendix A. The assumed cost trajectories for the two scenarios are presented in Figures 5-7.

As Power-to-Power energy storage requires charging with electricity from generation sources, the deployment of energy storage is inherently linked with the costs of generation. Scenario A assumes a moderate cost reduction in solar PV, coupled with no cost reductions for wind and Li-ion batteries. Scenario B is configured to asses the deployment of storage where there are high learning rates (cost reductions) for batteries, wind and in particular solar PV. The 70% cost reduction in solar PV and 40% cost reduction in wind between 2016 an 2040 are informed by cost projections made by BNEF

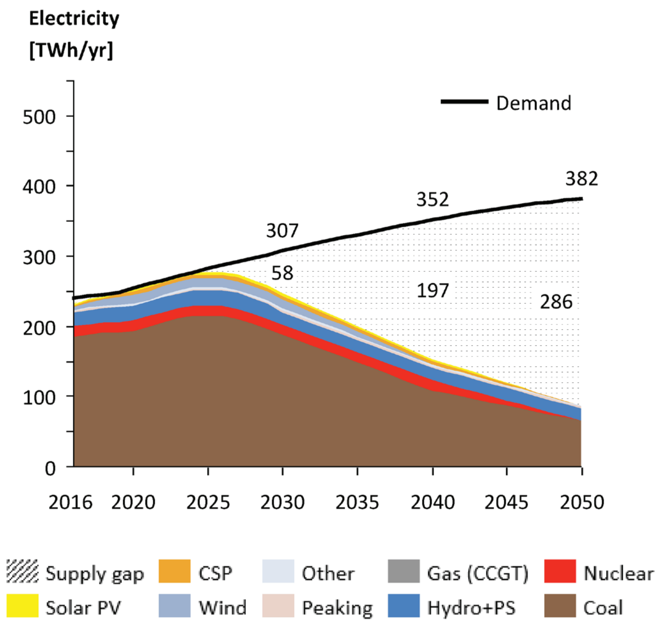

Fig. 4. Electricity supply gap caused by the planned decommissioning of the current generation [11]

as well as IRENA. Scenario B assumes Li-ion battery costs to decrease significantly to \$100/kWh by 2050 (installed capacity cost not LCOE). The cost assumptions for Scenario B are designed to test the implications on the energy mix for low cost VRE generation coupled with very low cost storage.

B. Sector Coupling Included in the Modelling

As described in Section II, Sector Coupling has the potential to positively influence the least cost energy mix. Power-to-Heat and Power-to-eMobility have the potential to introduce flexible electrical loads that reduce the battery storage and/or flexible generation required. In this paper a high level analysis of possible sector coupling that could be achieved through residential water heating and electric vehicles is presented. Further detailed studies on Sector Coupling are planned at the CSIR Energy Centre and will be included in future modelled scenarios. These studies include an assessment of heat demand within the residential, commercial and industrial sectors of South Africa.

1) Residential electric water heating: Due to the historical low-cost of electricity, South Africa already makes extensive use of Power-to-Heat energy conversion in the residential sector for water heating. Electric geysers (water cylinders), typically in the form of a 3kW/150l system, are widely used in the country for water heating. According to Statistics South Africa in 2016 there were 4.7 million households making use of EWH using a geyser [9]. Hot water storage presents an effective opportunity for introducing low cost energy storage. Assuming a 65 °C temperature change, and a cost of R3000 for a 150 l geyser, the cost of the thermal energy storage is R313/kWh$_t$, which is an order of magnitude lower than current battery prices.

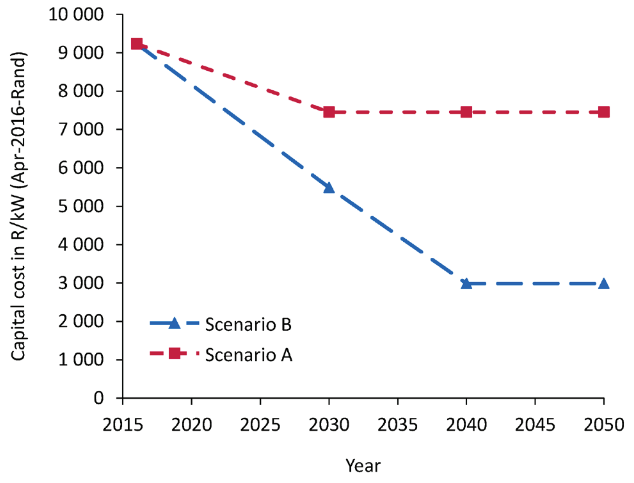

Fig. 5. Assumed cost reductions for Solar PV (including capital phasing)

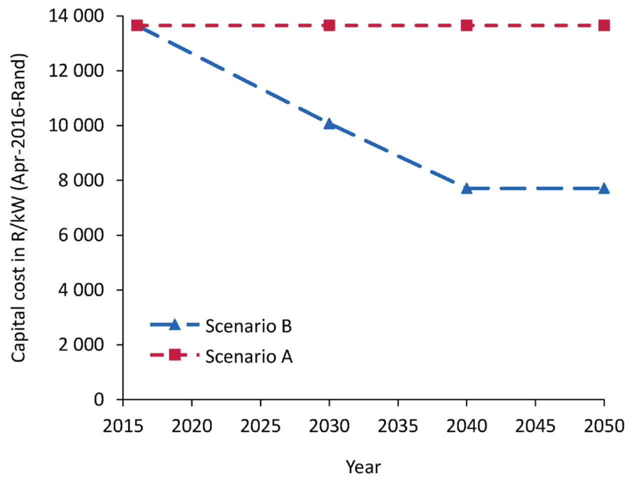

Fig. 6. Assumed cost reductions for wind (including capital phasing)

In order to estimate the potential for creating demand response through EWH a high level analysis was conducted by the CSIR Energy Centre [11]. Important parameters from this analysis are presented in Table II. The potential for daily demand shaping is based on a number of key assumptions which are marked with an asterisk in the Table. The results of the high level analysis show that based on the assumed population growth and electric water heating adoption rates, approximately 70 GWh/day could be available as a flexible load through EWH.

EWH demand response was included in the modelling of both Scenarios A and B. The demand response capability of the EWH was modelled to have intraday controllability (can be dispatched as needed on any given day) based on power system requirements but needs to have a net-zero energy balance on a daily basis (no substitution effect).

2) Electric vehicles: Direct coupling of Power-to-eMobility, through EVs has significant potential to enhance grid flexibility through smart charging. The adoption of electric vehicles in South African to date is small compared to the sale of conventional combustion engines. This is partly

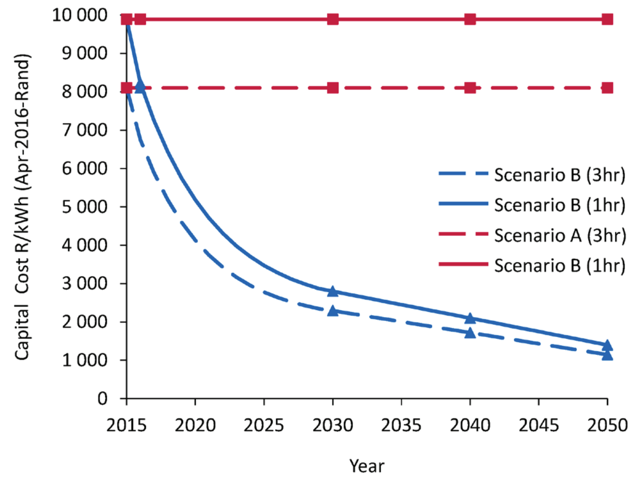

Fig. 7. Assumed cost reductions for battery storage (including capital phasing)

TABLE II
POWER-TO-HEAT: SECTOR COUPLING OF RESIDENTIAL HEAT DEMAND USING ELECTRIC HOT WATER HEATERS

Description	2016	2030	2050
Population [million]	**55.7**	**61.7**	**68.2**
Households [million]	**16.9**	22.4	27.3
Residents/household	3.29	2.75*	2.5*
Household with EWH [%]	28	50*	100*
Individual EWH Power [kW] **	3*	2*	1*
Demand shaping adoption [%]	0	25*	100*
Household with EWH [million]	**4.7**	11.2	27.3
Demand shaping [GWh/day] ***	0	14.9	72.3

Bold values indicate key input parameters from data sources [9], [11]
* Assumed value for high level analysis
** Assume a gradual transition to heat pumps with a COP of 3
* * * Demand shaping potential calculated assuming an 11% duty factor, assuming 4.7 million geyser with 3kW elements account for 13.7 TWh electricity end use based on Eskom IDM [15].

due to a lack of charging infrastructure as well as the cost of electric vehicles today. However, with continued declining lithium-ion prices, the costs of electric vehicles are expected to come down and boost sales into the future.

As with the EWH a high level analysis was conducted in [13] to estimate the potential for demand response through the smart charging of electric vehicles. In order to be conservative the demand response from a high uptake scenario of electric vehicles was not included in Scenario A, where Li-ion battery costs remain high. Therefore demand response from EVs was only applied to the case of Scenario B. In the modelling approach, it was assumed that the regulations, policies and infrastructure required to support the uptake of EVs would be in place. It was assumed that the average annual distance travelled by a passenger vehicle ranges between 15 000 to 20 000 km/yr. In the absence of robust assumptions on the expected daily EV fleet charging patterns, a conservative assumption of 10% of all EVs were assumed to be available in any hour of the day for use as a flexible option only accessing stored energy in excess of daily transportation consumption. More detailed studies on vehicle driving patterns are planned at the CSIR Energy Centre for future work.

Table III presents the results of the high level EV analysis. The results show that in the case of 10-million electric vehicles by 2050, in excess of 100 GWh/d could be available as flexible demand. The study assessed the implications of intra-day control of electrical vehicle charging as a demand response opportunity. Further opportunities also exist to access stored energy and inject such back into the grid, although vehicle-to-grid is currently not considered.

TABLE III
POWER-TO-EMOBILITY: FLEXIBILITY FOR A HIGH GROWTH RATE OF VEHICLES AND A HIGH PENETRATION OF EVS

Description	2016	2030	2050
Population [million]	**55.7**	**61.7**	**68.2**
Motor Vehicles [million]	**7**	12.3*	20.5*
EV adoption [%]	0	8.1*	48.9*
Number of EVs [million]	0.0	1.0	10.0
Demand shaping [GWh/day]**	0	10.1	101.4
Demand shaping [TWh/yr]	0	3.7	37

Bold values indicate key input parameters from data sources [11], [16]
* Assumed value for high level analysis

TABLE IV
COMPARISON OF ENERGY GENERATION MIX FOR THE YEAR 2050 FOR SCENARIO A AND B

Generation	Energy A		Energy B	
	[TWh]	[%]	[TWh]	[%]
Coal	60.2	15.4%	57.9	13.9%
Nuclear	0.0	0.0%	0.0	0.0%
Hydro	11.4	2.9%	8.5	2.1%
Wind	180.2	46.2%	171.3	41.2%
Solar PV	84.1	21.6%	137.7	33.1%
OCGT Gas	9.9	2.5%	8.7	2.1%
CCGT Gas	35.2	9.0%	2.3	0.6%
CSP	0.0	0.0%	0.0	0.0%
Biomass	3.1	0.8%	1.6	0.4%
Battery	0	0.0%	16.4	4.0%
Pumped Hydro	6.1	1.6%	11.1	2.7%
Total	390.1*	100%	415.7*	100%

* Total energy exceeds 382 TWh system demand due to the round trip efficiency of the storage.

C. Reserve Requirement

The reserve requirements made for both scenarios were based on the publically available Eskom Ancillary Services Technical Requirements for 2017/18 - 2021/22 document [14]. From 2022 onwards, the Instantaneous, Regulating and 10-Minute reserve requirements were increased as a function of both the increasing electricity demand and guidelines in [14] regarding the largest single contingency. In the expansion planning model, a total operational reserve is modelled which is the sum of Instantaneous, Regulating, 10-Minute, Supplemental and Emergency reserves. In order to remain conservative, the reserve requirements were increased for Scenario B due to the higher renewable energy penetration but no studies were performed to verify these reserve requirements. Therefore it should also be noted that the system reserve requirements assumed for each model have increased from Scenario A (5.6 GW by 2050) to Scenario B (9.6 GW by 2050).

IV. RESULTS AND DISCUSSION

A. Flexibility Resources

Results for Scenario A and B are presented in Figures 8 and 9 respectively in terms of installed generator capacity, while the energy mix for 2050 is presented in Table IV. The least-cost models for both scenarios show a significant deployment of solar PV and wind as the bulk source of electrical energy supply. Naturally the low cost of solar PV, batteries and to an extent wind in Scenario B, result in a changing energy mix from that of Scenario A. The installed capacity of 55 GW solar PV and 60 GW wind in Scenario A is increased to 81 GW solar PV and 72 GW wind in Scenario B.

In the context of this paper, the focus is placed on the flexibility resources that are built as an outcome of the least cost optimisation for each of the two scenarios. These include: pumped hydro, batteries, biomass/-gas, peaking open cycle gas turbines (natural gas), combined cycle gas turbines (natural gas) and CSP.

Figure 8 shows that at the assumed costs for Scenario A, no battery storage is built. Instead, flexible generation in the form of CCGTs using natural gas is chosen as the more cost effective option. A total of 12 GW of CCGTs natural gas turbines are built in this scenario by 2050, which generate 9% of the total energy. A total of 26 GW of OCGTs are built, but these only generate 3% of total energy, as shown in Table IV.

In contrast, Figure 9 shows that Scenario B deploys extensive amounts of battery storage, with an installed capacity of 17 GW (48 GWh) by 2050. This extensive deployment of stationary storage in the form of batteries in Scenario B offsets a significant portion of gas fired generation deployed in Scenario A. It should be cautioned that it is not only the assumed future low-cost of battery storage but also the very low-cost solar PV that drives the extensive deployment of batteries in Scenario B.

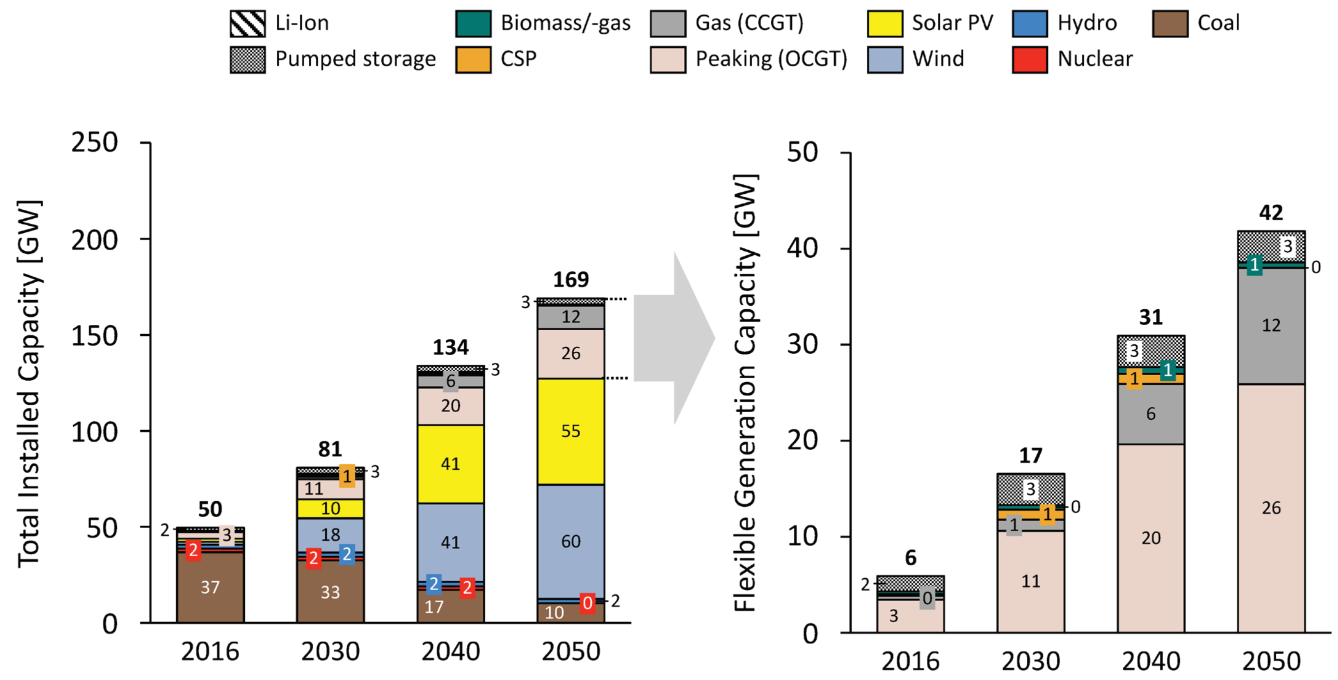

Fig. 8. Flexibility resources for Scenario A to compliment 55 GW PV, 60 GW wind and 169 GW total installed capacity

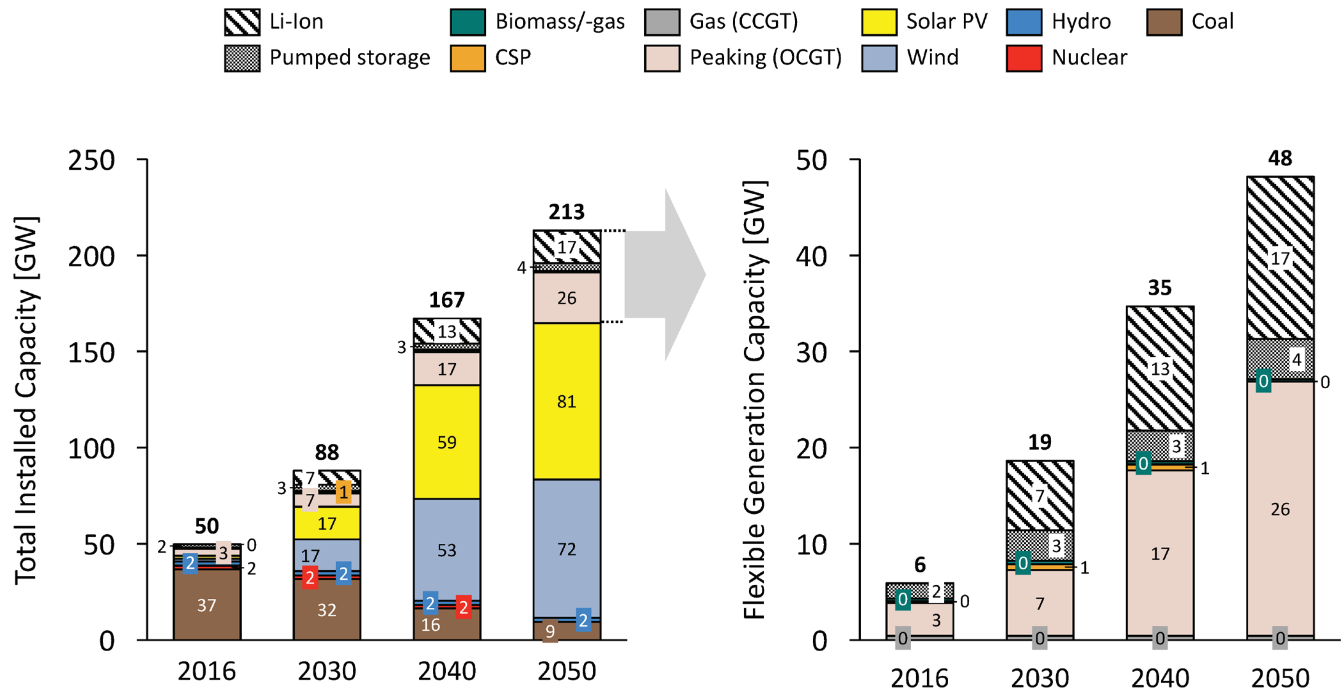

Fig. 9. Flexibility resources for Scenario B to compliment 81 GW PV, 72 GW wind and 213 GW total installed capacity

B. Natural Gas Requirements

The natural gas demand for electrical energy requirements for both Scenario A and B is summarised in Figures 10-11. Although a number of options are available to provide this natural gas demand requirement, the predominant options available in the medium-term would be imported pipeline natural gas from the Southern African region (likely Mozambique) or liquefied natural gas (LNG) import terminals at strategic port locations employing floating storage and regasification unit (FSRU) technology to minimise mainland infrastructure requirements e.g. Richards Bay, Coega, Saldannha Bay. In this context, the equivalent annual offtake for natural gas demand requirements for scenario A and B are illustrated in Figure 11 (considered in mmtpa volume of LNG but the equivalent natural gas volumes via pipeline imports could also be considered on an equivalent

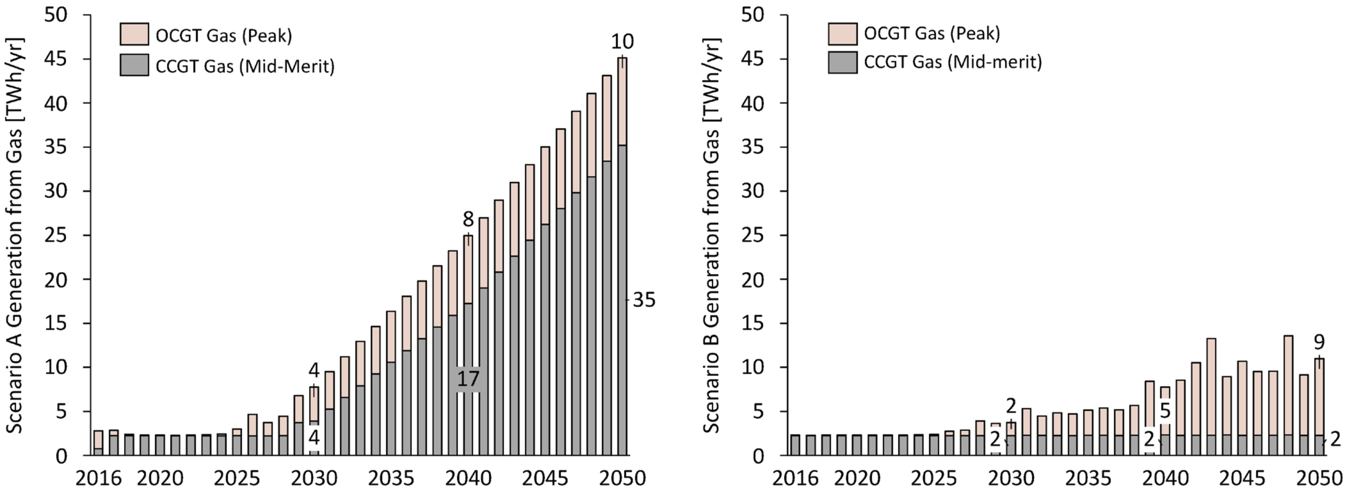

Fig. 10. Electrical energy generation using natural gas fired turbines for both scenarios

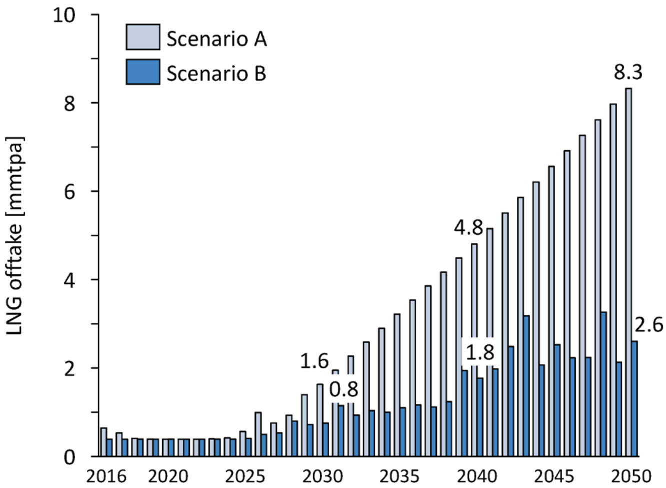

Fig. 11. Equivalent LNG offtake for electrical energy power generation for both scenarios

basis). It is clear that a significantly reduced offtake should be expected in Scenario B when stationary storage (batteries) are deployed.

Assuming a typical monthly refilling cycle and a typical medium to large 100 000-150 000 m^3 FSRU, the LNG offtake would need to at least 0.5-0.8 mmtpa for 1 FSRU at one of the ports previously mentioned. These offtake levels occur from 2025 onwards in both scenarios but at a considerably slower uptake in Scenario B relative to Scenario A. Scenario A LNG offtake would grow to 1.6 mmtpa by 2030, 4.8 mmtpa by 2040 and 8.3 mmtpa by 2050 whilst Scenario B this is only 0.8 mmtpa by 2030, 1.8 mmtpa by 2040 and 2.6 mmtpa by 2050. At a global level, LNG demand in 2017 was 293 mmtpa [17]. This is expected to grow to 314 mmtpa by 2020 and 479 mmtpa by 2030 [18].

Thus, if the cost trajectories assumed for stationary storage are realised or not, South Africa's demand for LNG would be a very small component of global demand by 2030 (less than 0.2-0.3%) and would likely need to be supplemented by additional demand from other sectors (industrial offtake, transportation and/or domestic use).

The renewable energy penetration levels for both Scenarios in 2030 do not result in significant curtailed energy (less than 1TWh). As such battery energy storage displaces a portion of the gas fired plant in Scenario B. The very low load factors of the OCGT fleet, and relatively high CAPEX cost of batteries as compared to OCGT make the displacement of all OCGTs uneconomic. Beyond 2030 the high renewable energy penetration levels in Scenario B result in large levels of curtailed energy, leading to the inclusion of 3h battery storage, and the further displacement of gas fired power plants. Despite the extensive deployment of storage in Scenario B, a total of 55 TWh/year is curtailed by 2050. Assuming 50 kWh/kg to produce hydrogen through electrolysis, this curtailed energy could be used to produce 1.1 million tonnes of hydrogen. Alternatively this energy could be absorbed as process heat and offset the direct consumption of fossil fuels for thermal energy. Curtailed energy is currently not assigned any economic value in the model. However, if these additional value streams can be realised through Sector Coupling, there is the potential for further cost reductions in the least cost electricity model.

The analysis did not assess the impact of cost reductions in battery storage if the future energy mix continues to be provided by predominately coal based generation. In such a scenario there would be little curtailed energy and the system flexibility requirements would be substantially reduced. Depending on the extent of further battery cost reduction beyond those considered, the optimal system level deployment of low-cost batteries in such an energy mix may also include the provision of additional reserves and the further displacement of a portion of gas-fired generation. This would need to be an area of further research.

V. Conclusions

An integrated energy system based on low-cost electricity from wind and solar PV has the potential to decarbonise electricity, heat and transportation in South Africa. In this paper the concept of sector coupling, combined with various forms of energy storage were presented. An analysis of residential heat demand demonstrates the potential for coupling of heat to electricity, with approximately 70 GWh/day available for demand shaping. Should South Africa see a high uptake of 10-million electric vehicles by 2050, the development of a smart charging network could allow for a further 100 GWh/day in flexible demand. The results from two scenarios with high penetrations of renewable energy were presented where wind and solar PV dominated as technologies. The results show that if battery costs do not decrease it is more feasible to utilise flexible generation from natural gas fired combustion turbines. However, with more aggressive cost reductions for wind, solar PV and batteries, an extensive 17 GW/48 GWh of storage is deployed by 2050. The deployment of batteries has the potential to reduce the LNG offtake from 8.3 mmtpa to 2.6 mmtpa in 2050 in the modelled scenarios.

Despite the extensive deployment of storage, a significant 55 TWh of energy from solar PV and wind is optimally curtailed when considering only the electricity sector. Therefore, effective sector-coupling could make extensive use of this curtailed energy in a number of ways to be identified as part of future research.

Appendix A
Modelling Methodology Expanded

This appendix provides details on modelling framework used in this study. As shown in Figure 12 the modelling framework (PLEXOS®) considers all cost components explicitly, including: overnight capital cost, construction time, capital phasing schedule, Fixed Operations and Maintenance (FOM), Variable Operations and Maintenance (VOM), fuel costs and efficiency (heat rate). In order to attain the generation profiles for wind and solar, profiles for 27 supply areas (defined by Eskom) were aggregated into one wind and one solar profile [12].

For this paper all costs were based on the draft IRP 2016 document [4]. Due to availability of real world PPA prices, which are a proxy for real LCOE, the specific CAPEX costs for wind and solar PV are reverse engineered using the approach outline in Figure 13. A summary of relevant generator and storage costs is presented in Tables V-VIII.

Appendix B
Exemplary weeks

An example week showing the dispatch of the optimised energy sources for Scenarios A and B in 2050 is illustrated in Figure 14 and 15 respectively. It should be noted that the same week is illustrated, and the variations in dispatch are due to the different optimal energy mix for each Scenario. The comparatively lower levels of renewable energy penetration in Scenario A result in no curtailed energy, and the required flexibility is achieved via demand response, gas, hydro, and the downward dispatch of coal. Demand response with excess midday PV energy provides increased flexibility without the need for battery storage. However, in Scenario B (Figure 15) the increased renewable energy penetration results in substantial excess energy that would otherwise be curtained. In that Scenario B the deployment of 3h battery storage combined with demand response enables the cost effective shifting of excess midday energy (from PV) into periods that would otherwise have been supplied by gas.

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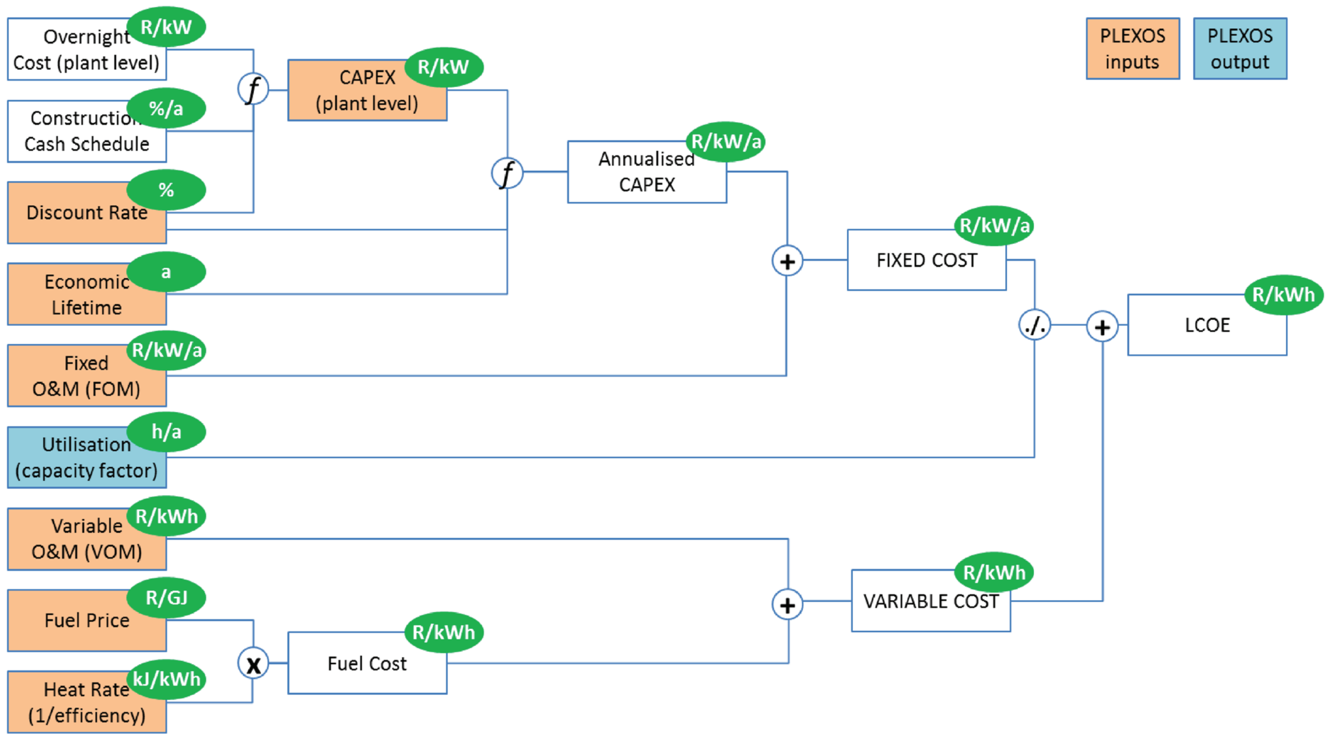

Fig. 12. PLEXOS modelling framework for generator cost drivers [11]

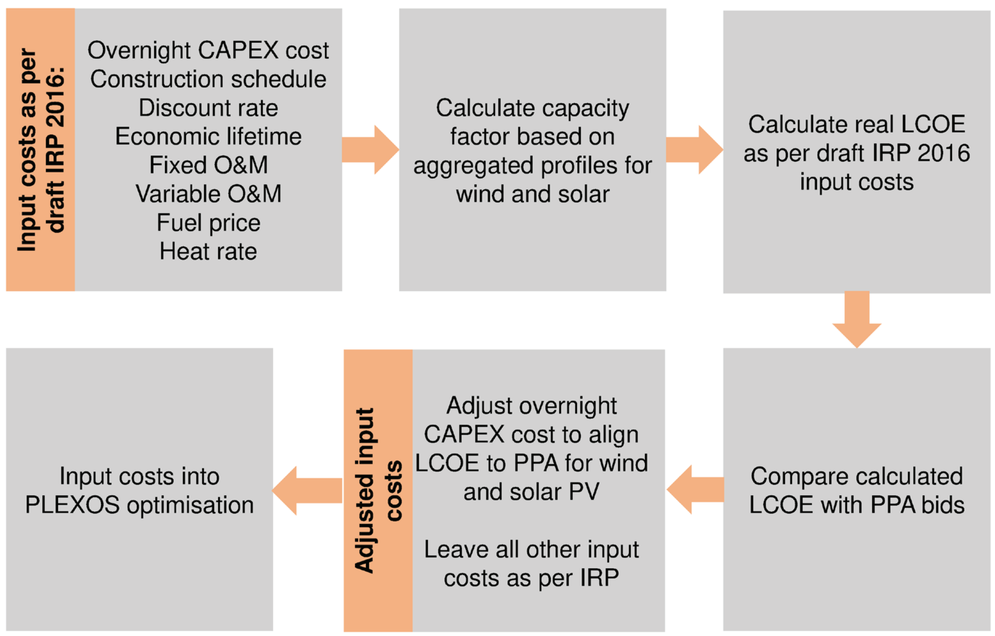

Fig. 13. Methodology to adjust CAPEX costs for wind and solar PV to align with PPA submissions

TABLE V
TECHNOLOGY COST INPUT ASSUMPTIONS FOR RENEWABLE GENERATORS AND FOR SCENARIO A

Property	Unit	Wind	Solar PV (fixed)	Battery (1h)	Battery (3h)	Pumped Hydro	CAES
Rated Capacity	[MW]	100	10	3	3	333	180
Capital Cost (2016)*	[USD/kW]	928	628	672	1652	1893	1881
Capital Cost (2030)*	[USD/kW]	928	507	672	1652	1893	1881
Capital Cost (2040)*	[USD/kW]	928	507	672	1652	1893	1881
Capital Cost (2050)*	[USD/kW]	928	507	672	1652	1893	1881
Fuel Cost	[USD/GJ]	0	0	0	0	0	10.2
Heat Rate	[GJ/MWh]	0	0	4045	4045	0	4444
Rnd.Trip Eff.	[%]	N/A	N/A	89%	89%	78%	81%
Fixed O&M	[USD/kW/a]	34	14	42	42	14	14
Variable O&M	[USD/kW/a]	0	0	0.2	0.2	0	0.2
Load Factor	[%]	36%	20%	4%	12%	33%	22%
Economic Lifetime	[a]	20	25	10	10	50	40

* Capital cost based on capital phasing (found in [13]), discount rate and economic lifetime.
** All costs in April 2016 Rand and using a USD:ZAR exchange rate of 14.71

TABLE VI
TECHNOLOGY COST INPUT ASSUMPTIONS FOR RENEWABLE GENERATORS AND FOR SCENARIO B

Property	Unit	Wind	Solar PV (fixed)	Battery (1h)	Battery (3h)	Pumped Hydro	CAES
Rated Capacity	[MW]	100	10	3	3	333	180
Capital Cost (2016)*	[USD/kW]	928	628	640	1573	1893	1881
Capital Cost (2030*	[USD/kW]	685	373	190	468	1893	1881
Capital Cost (2040)*	[USD/kW]	524	203	143	351	1893	1881
Capital Cost (2050)*	[USD/kW]	524	203	95	234	1893	1881
Fuel Cost	[USD/GJ]	0	0	0	0	0	11.2
Heat Rate	[GJ/MWh]	0	0	4045	4045	0	4444
Rnd.Trip Eff.	[%]	N/A	N/A	89%	89%	78%	81%
Fixed O&M	[USD/kW/a]	34	14	42	42	14	14
Variable O&M	[USD/kW/a]	0	0	0.2	0.2	0	0.2
Load Factor	[%]	36%	20%	4%	12%	33%	22%
Economic Lifetime	[a]	20	25	10	10	50	40

* Capital cost based on capital phasing (found in [13]), discount rate and economic lifetime.
** All costs in April 2016 Rand and using a USD:ZAR exchange rate of 14.71 [4];

TABLE VII
TECHNOLOGY COST INPUT ASSUMPTIONS FOR CONVENTIONAL GENERATORS FOR SCENARIO A AND B

Property	Unit	Coal (PF)	Coal (FBC)	Nuclear	OCGT	CCGT	Hydro Imp.
Rated Capacity	[MW]	750	250	1400	132	732	2500
Capital Cost (2016)*	[USD/kW]	2674	3219	5304	597	677	4572
Capital Cost (2030)*	[USD/kW]	2674	3219	5161	597	677	4572
Capital Cost (2050)*	[USD/kW]	2674	3219	5161	597	677	4572
Fuel Cost	[USD/GJ]	1.9	0.9	0.5	10.2	10.2	0
Heat Rate	[GJ/MWh]	9812	10788	10657	11519	7395	0
Fixed O&M	[USD/kW/a]	63	42	66	11	11	61.7
Variable O&M	[USD/kW/a]	5.4	11.8	2.5	0.2	1.5	0
Load Factor	[%]	82%	82%	90%	6%	36%	70%
Economic Lifetime	[a]	30	30	60	30	30	60

* Capital cost based on capital phasing (found in [13]), discount rate and economic lifetime.
** All costs in April 2016 Rand and using a USD:ZAR exchange rate of 14.71

TABLE VIII
TECHNOLOGY COST INPUT ASSUMPTIONS FOR RENEWABLE GENERATORS FOR SCENARIO A AND B

Property	Unit	CSP (tower,9h)	Biomass (forestry)	Biomass (MSW)	Landfill Gas	Biogas	Bagasse (gen)
Rated Capacity	[MW]	125	25	25	5	49	53
Capital Cost (2016)*	[USD/kW]	6599	3301	10754	2111	867	2419
Capital Cost (2030)*	[USD/kW]	3920	3301	10754	2111	867	2419
Capital Cost (2050)*	[USD/kW]	3920	3301	10754	2111	867	2419
Fuel Cost	[USD/GJ]	0	2.2	0	0	7.7	5.5
Heat Rate	[GJ/MWh]	0	12386	18991	12302	11999	19327
Fixed O&M	[USD/kW/a]	69	113	440	161	29	26
Variable O&M	[USD/kW/a]	0	4.5	7.8	4.2	3.5	1.8
Load Factor	[%]	57%	85%	85%	85%	20%	50%
Economic Lifetime	[a]	30	30	30	30	30	30

* Capital cost based on capital phasing (found in [13]), discount rate and economic lifetime.
** All costs in April 2016 Rand and using a USD:ZAR exchange rate of 14.71

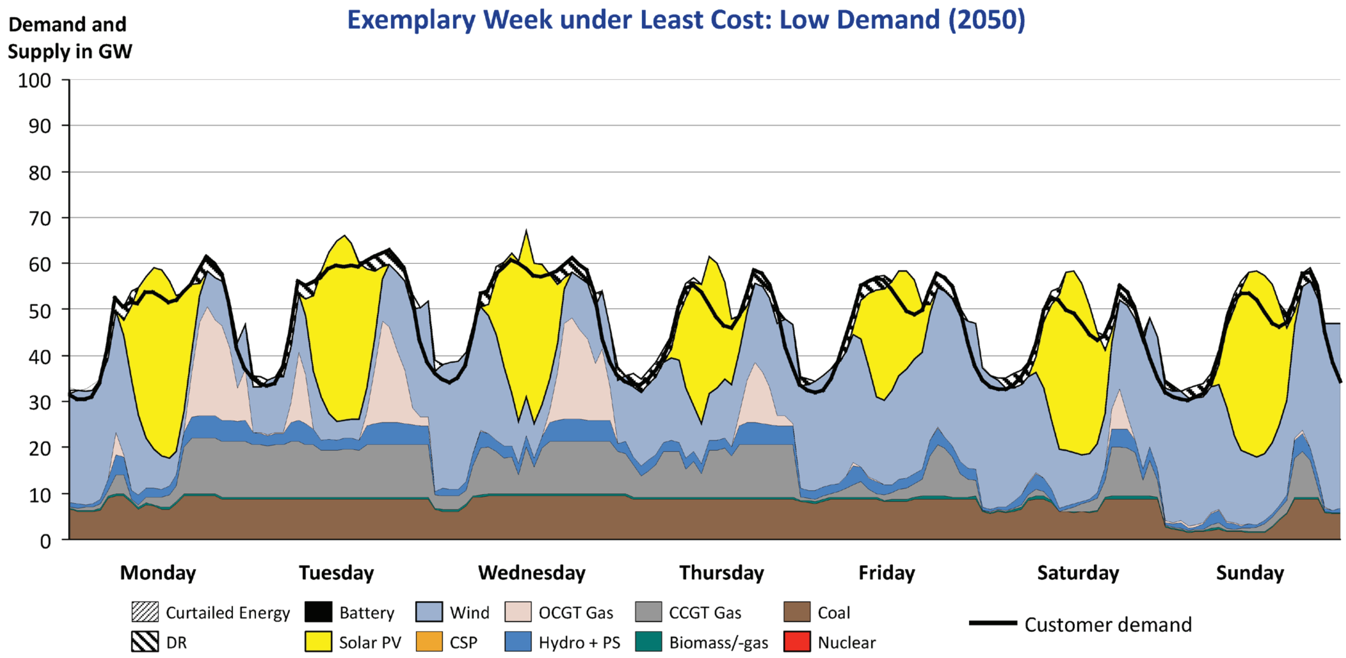

Fig. 14. Exemplary week from Scenario A in 2050

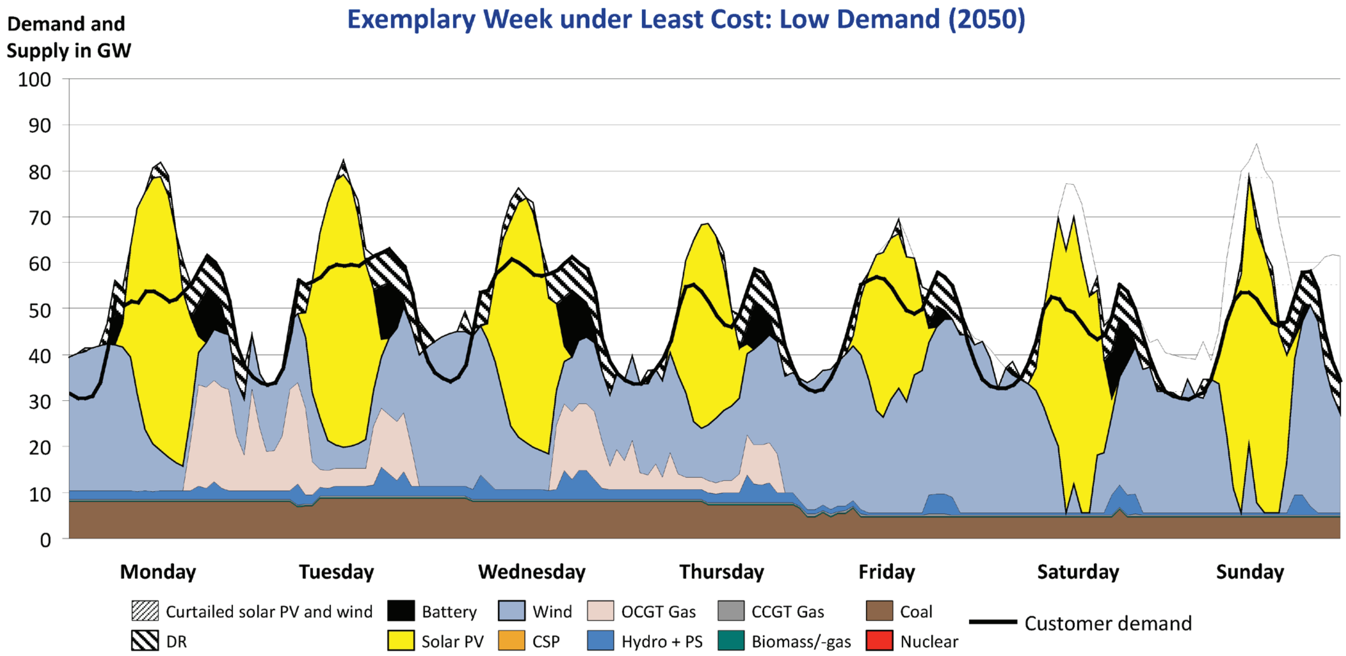

Fig. 15. Exemplary week from Scenario B in 2050

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