Combined system-wide value of sectoral electrical demand flexibility in South Africa's integrated energy system: an application in SATIM.

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Abstract

There is a growing body of research on demand-side flexibility in energy systems, including evaluating total demand resource potentials, individual system benefits, technical capabilities of enabling technologies, behavioural aspects, and regulation and market designs to incentivize participation. However, a gap lies in determining the individual and combined overall system-wide value of multiple interacting future demand-side resources in the South African context and doing so using an integrated multi-sector full energy system model.

This paper models and presents the expected system-wide value, and future energy system planning implications, of including flexible electrical demand response (DR) in the future South African energy system evolution focusing on the electricity sector compared to a baseline reference scenario from 2020 to 2050. It evaluates the impact of increased penetrations of controllable DR in the residential, industrial and commercial sectors using the South African TIMES model (SATIM). Specifically measured and reported for the South African electricity system context are (1) the per kWh system value of individual and combined sectoral flexible end-uses, (2) the change in peak grid demand, and (3) the change in the least-cost national electricity capacity expansion plan.

This evaluation does not attempt to quantify the fully achievable future demand resource potentials, or estimate the total costs of implementation, but rather determines what the combined system-wide value and planning impacts of various flexible demands could be, if realized. This provides insights for the justification of enabling economic incentives and programs, incorporation of new demand-side resources into national and municipal energy planning activities, guidance for focus areas for further research and development, and insights to the private sector for potential high value future investments and innovation opportunities.

1 Introduction

Flexible Demand (FD) refers to a change in energy demand in response to a price signal, incentive or retrofit program, or direct control of end-use demand technologies. Flexible demand in an energy system covers a wide range of energy services where there is an option to shift use in time, forgo or reduce energy use, or store energy in some way. In brief, flexible demand could refer to any of the following practices:

- Using alternative energy sources, carriers, or technologies to meet the same demand more efficiently.
- Shifting the time at which the energy service is required or foregoing the service.
- Storing energy in some form, such as in batteries, pumped hydro, or thermal storage.
- Using transmission links to trade energy regionally between countries, provinces, or even individual consumers.
- Inter-sectoral linkages and power-to-X: such as flexible charging of electric vehicles, or flexible production of hydrogen through electrolysis for use in power-to-gas, power-to-power, or power-to-liquids applications.

Demand Response (DR), which is the focus of this study, is a type of FD referring specifically to electricity demands responding dynamically to changes in the status of the system, typically in time-frames such as a day, but also longer such as over seasons – typical time-shifting methods are shown in Figure 1. DR is attractive in energy systems with numerous potential benefits and have been documented extensively, popularised early as in (Gelling et. al. 1989) and revisited more recently as in (Lund et. al., 2015). Table 1 provides a summary of DR benefits appropriate to the electricity system (Ireland et. al., 2019) – the table also indicates which system benefits are directly measured in this study (shaded green), which are currently excluded (shaded blue), and which can be studied in future using SATIM (shaded orange).

DR provides operational, economic, planning, and environmental benefits to energy systems with the potential of improving their efficiency, integrating more variable renewable energy, reducing emissions, lowering cost of supply, and improved reliability and stability of electricity systems. More specifically, FD provides a way of reducing peak electricity demands, and therefore the need for peaking generation capacity often being costly to run; it allows a reduction in spinning reserves, can allow higher penetrations of variable generation technologies such and wind and solar, and it can allow investments in new transmission and distribution networks to be deferred and losses reduced. RE is attractive to South Africa because of its low cost in relation to other plants, and its reduction of GHG emissions, and domestic availability among others. Recently variable renewables are increasingly being incorporated into the South African electricity supply system, both on the national centralised grid through the REIPPPP programme and by individual consumers. Significantly more RE is projected to be added in future under national policy and a least-cost basis, such as in the Integrated Resource Plans (IRP) of the country (DoE, 2011, 2016, 2018) and as modelled by a number of other institutions shown in Figure 8.

Table 1 - Summary of flexible demand benefits in electricity systems (Ireland et. al., 2018)

Operational Benefits	Economic Benefits	Planning and Environmental Benefits
Lessened need for peaking plants and fuel consumption	Overall reduced electricity price and price volatility	Deferral/Reduction of generation and transmission capacity requirements
Reduced thermal plant cycling, lowering start-up costs, and ramping efficiency losses	Economic inclusion of more low-cost variable renewables	Higher penetrations of RE lessening the economic burden of national contributions to global climate goals
Improved reliability and stability of electricity systems	Reduced electricity storage requirements and cycling losses and degradation	Environmental and health benefits (GHG, land use, air, and water quality)
Ancillary services such as grid frequency, voltage support, and spinning reserves	Energy affordability and global industrial electricity price competitiveness	Added flexibility adapting to unforeseen changes in technology or global commodity and carbon prices
Green: Measured in this study	***Blue: Not measured in this study***	***Orange: Not measured in this study but possible with SATIM framework***

Tendencies towards decentralisation and energy independence are particularly evident among South African municipalities. They are challenging the current regulatory regime procuring their own renewable energy from IPP's, while paving the way for regulated embedded generation in households and commercial businesses. Local governments are set to become major participants in an energy system that is more amenable to demand flexibility. Municipalities are likely to be the actors that will be positioned to best understand the electricity demand requirements within their jurisdictions and would be key actors in incentivizing end-users to participate in demand flexibility programs. They can then also act as aggregators enabling them to provide predictions of firmly "dispatchable" demand resources to the centralised generation and transmission system operators.

Recent advances in distributed energy costs, mini-grid technology and innovative business models have also made decentralised solutions a strong and economically viable opportunity for rural electrification as it avoids expensive MV network extension, purchases from Eskom and allows new smart-grid networks to be developed. The latter will increase the share of low-carbon electricity generation if renewable; provide local employment; and allow the potential for future grid-interconnection to strengthen end-of-grid networks and allow flexible resources to balance supply (ERC 2017; Carbon Trust 2017). DR is often included as a key system capability of new mini-grids to be developed.

In South Africa DR could realise many of these potential benefits if implemented successfully. However, to do this it's full value needs to be understood more holistically within the full national energy system, for whom this value can be realised, and how to include these resources appropriately in national energy planning activities. The primary objective of this study is to provide insights into these questions, and a framework with which to continually improve our understanding of these resources within South Africa, now and in the future.

1.1 Energy system models in South Africa and the South African Times Model (SATIM) for Flexible Demand impacts evaluation

To adequately understand the combined impacts of flexible demands in an energy system a fully integrated systems model is required and a full suite of flexible demands within various sectors are needed. If only a limited amount of flexible demand is included in a study, only in a particular sector, and excluding fuel switching, it will not show potential diminishing returns and other system interactions (e.g. as more flexible demands are added to the system they will compete to add value to the system, being utilised at the highest impact time-periods and then saturating the benefits that each marginal flexible demand adds). The DR system value also depends specifically on the shape of the demand in each sector and end-use as its temporal profile is what needs to be met by the rest of the system and from which changes to that specific profile would have upstream effects.

Studies investigating the potential of demand flexibility are also often done using a fixed planned future power system as a baseline, then adding flexible demands to that system and using a higher resolution operational model to determine the impacts it may have in the system. The strength of an integrated medium to long-term system optimization model is that it will evolve the system in a way to maximise the value of all resources that it has available to it – including new flexible demand resources.

Several large energy system modelling frameworks and softwares are currently in use within South Africa. These include a TIMES model, which is used by the Energy Research Centre (ERC) at the University of Cape Town - called SATIM; PLEXOS, which is used at the Council for Scientific Research (CSIR), Department of Energy (DoE) and Eskom; and OSeMOSYS, which is used by a different division within the DoE for the national Integrated Energy Plan (IEP). PLEXOS models used in South Africa are highly detailed models specifically applied to the power sector. These models contain higher time resolution for energy profiles and include detailed information on system constraints and reliability requirements, trading off additional non-electricity, and sectoral disaggregation details on the demand side compared to SATIM and OSeMOSYS.

The South African TIMES Model (SATIM) model forms the basis of the system value and impact analysis of the research presented in this paper. SATIM covers all economic and energy sectors of South Africa and is developed within the Energy Systems, Economics, and Policy Group of the Energy Research Centre within the University of Cape Town in South Africa. It undergoes continual development, updates, and maintenance, with multiple internal and external stakeholders. For the SATIM model and documentation see: energydata.uct.ac.za/organization/erc-satim). SATIM is based on TIMES which is a partial equilibrium linear optimisation modelling framework developed by the International Energy Agency (IEA-ETSAP, 2018).

SATIM considers not only the demand for electricity but also the energy demands and their non-electric energy carriers (e.g. for transportation and industrial processes), and how these impact other sectors and vice-versa. It also allows holistic evaluation of scenarios where the full South African economy is subjected to greenhouse gas emission constraints. It has a detailed representation of individual end-uses and their temporal profiles within each sector; transmission and distribution capacities and their respective losses per sector; and can define specifically which end-uses can become flexible and to what degree with sufficient granularity. SATIM also allows for the competition between different demand flexibility options to be understood, such as electrical demand response of water heating versus simply replacing electric water heaters with solar water heating - the same is true for any potential flexible electrical demand that could switch fuels. SATIM potentially offers a tool with unique benefits and capabilities for investigating the topic of flexible demand.

SATIM can also be linked to an economy-wide model (eSAGE) in a version of the model called SATMGE. This allows for an analysis of the macro- and socio-economic impacts of energy decisions and investments on the South African economy (see Arndt et al. 2016 and Merven et al. 2017 for more details on the model). The current phase of this study focuses on using SATIM only and not SATIMGE.

This paper will follow with Section 2 describing the methodology used for the study, Section 3 describing the reference scenario and baseline from which to measure potential system impacts and value, Section 4 presenting the results of the inclusion of demand response as a flexible demand resource, and Section 5 completes the paper with conclusions and insights from the study and a description of potential high-impact future work areas.

2 Methodology for impact evaluation and system value calculation

The outputs of SATIM provide projections for the future least-cost system evolution and energy system investment projection scenarios comparable to those of the DoE IRP and IEP processes (DoE, 2011; 2016; 2018). The model endogenously choses the most appropriate end-use supply technologies, investments in energy efficiency measures, and fuel switching capabilities, all of which compete with the electrical demand response resource available to the system.

The potential system impacts of DR are demonstrated by measuring the differences in the future least-cost system configurations with DR included as a resource, compared to the baseline scenario without DR – thereafter the deviations from the baseline cost optimal system can be quantified and analysed.

In SATIM, the core of the demand representation is that of individual demands for energy services or useful energy, not specific energy carriers or final demands. The final energy demand (e.g. the demand for electricity) is a result of the model, based on the least-cost demand technology mix and their necessary energy carriers. This provides a more holistic picture of the energy system and supply-demand interactions, allowing for endogenous fuel switching and the switch to more efficient technologies. Also presented here are increased temporal profile resolutions of individual end-use demands within different sectors and variable renewable energy feed-in profiles for wind and solar PV.

SATIM, however, currently has a less detailed intra-annual time resolution (72 representative timesteps) and does not currently account for certain technical details in the power sector such as individual power plant ramp-rate constraints and short-term unit commitment. Figure 2 shows a map of the energy demand disaggregation in SATIM and the demands which are identified to be flexible now or in the future either using electric demand response flexibility (the focus of this study), fuel switching, or new strategic demand growth uses such as power-to-X or flexible electrical seawater desalination.

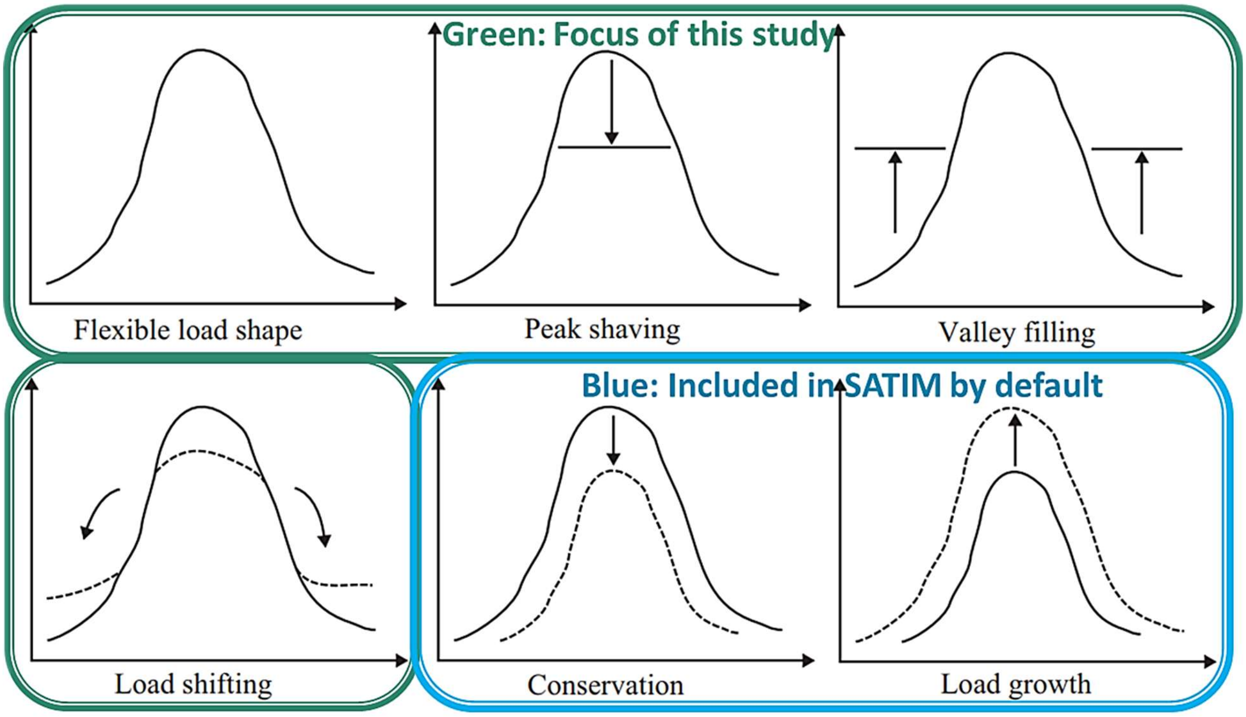


Figure 1: Examples of DR changing the shape and total amount of electrical demands. Circled in green are flexibility options specifically focused upon and measured in this study while circled in blue are included in SATIM by default but not reported on or analysed. Adapted from (Gelling et. al., 1989) and (Lund et. al., 2015)

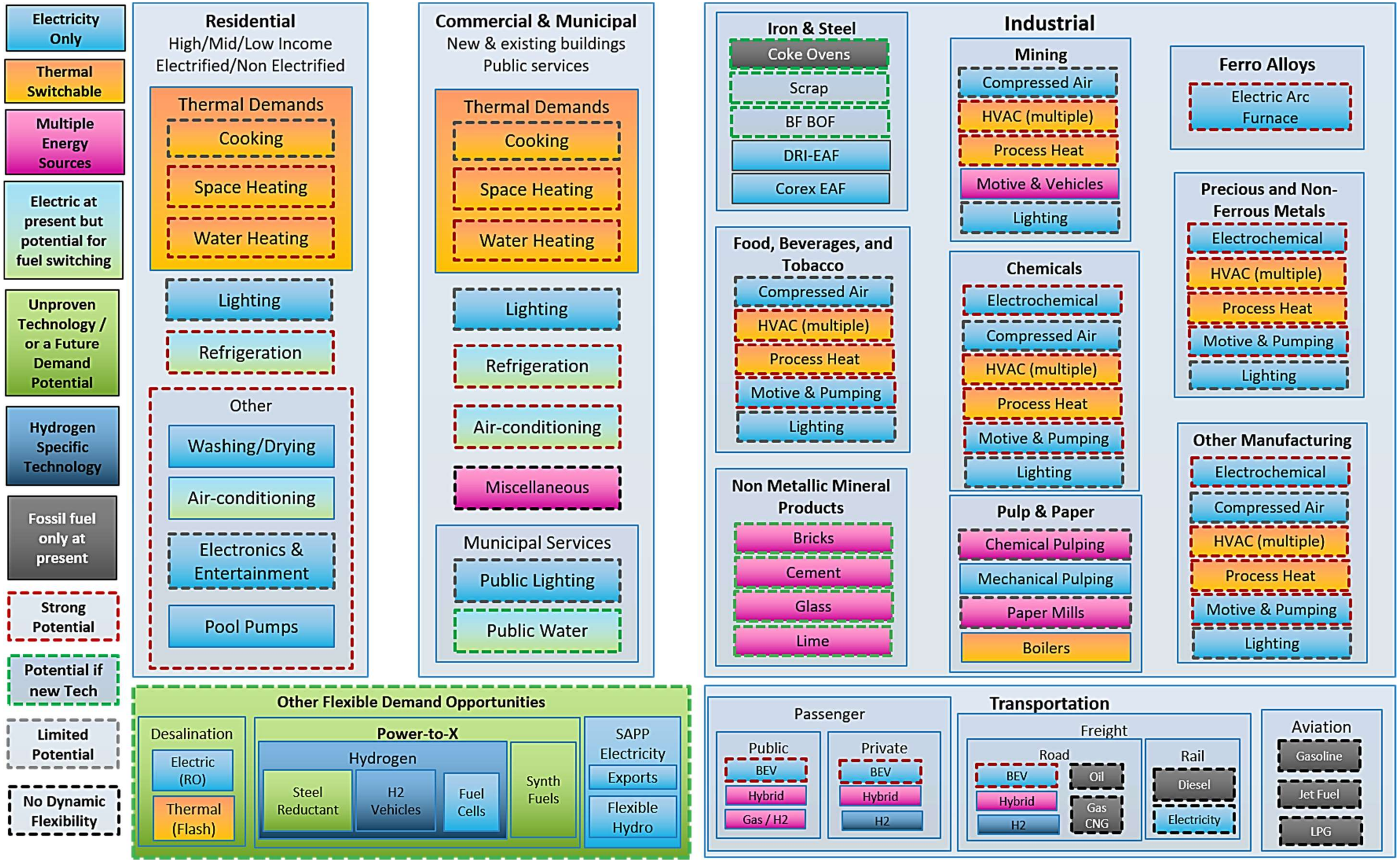


Figure 2: End-use demand resource map of modelled sectors in SATIM. Demands are mapped based on fuels that they can be served by, their expected current flexibility potential, and expected future flexibility potential. Future flexible demand resources are outlined in green and not modelled in this specific study – these are intended for future work and investigation in the SATIM model.

2.1 System Value of individual and combined flexible demands

The "system value" of DR measured in this study is defined to be the total combined measured benefits which DR provides the system resulting from the differences in optimal system configuration after its inclusion as a resource. These benefits, along with any other measurable benefits, would be "stacked" to give the combined total system value of DR. This total system value could then be compared to any expected costs of a DR implementation to give the overall net benefit of a flexible demand program, and thus provide the justification for its implementation from the perspective of a particular stakeholder's achievable scope of benefits and expected costs. Figure 3 depicts this graphically and indicates the focus of system benefits of this paper.

Specifically measured in this study are the stacked benefits resulting from a change in the centralised generation capacity expansion plan, transmission and distribution investment deferrals, and power generation fuel savings. These are measured for each economic demand sector from 2020 to 2050, in isolation and all combined, for two different market participation penetration levels. The expected costs of implementation of the necessary programs within each sector, and the actual future total achievable DR resource penetration/participation potential are not quantified here.

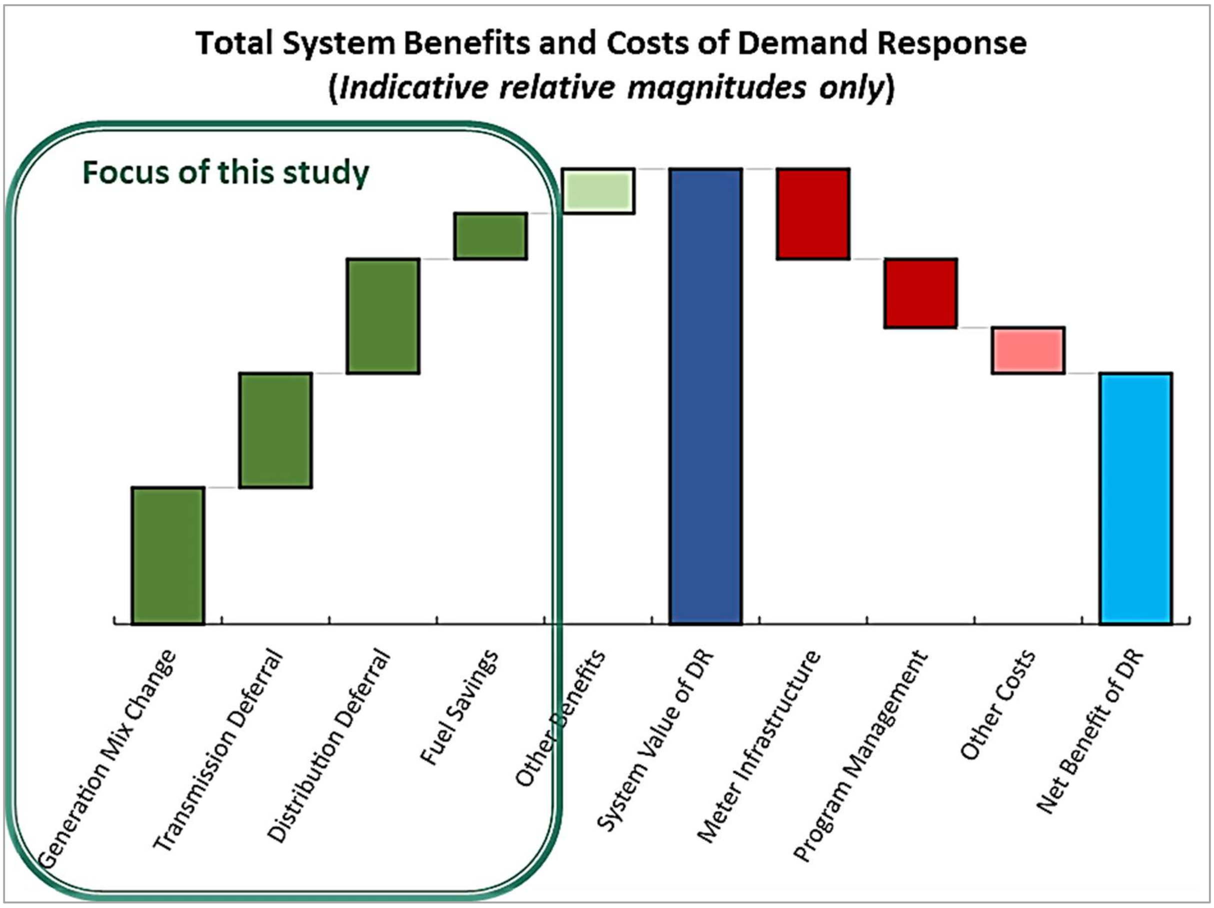


Figure 3: Figure of system benefit value stacking of demand response and anticipated potential implementation costs to combine to evaluate a net benefit. This focus of this study excludes the cost of implementation.

2.2 Model Improvements required in SATIM

2.2.1 Increased Time Resolution

To capture the inter-hour variations in the electricity system operation the demand and supply timeseries are represented chronologically at an hourly resolution between 5am and 10pm, with 7 hours between 10pm and 5am represented by a single average value. To accommodate seasonal and weekly changes in profiles, two day types (Weekdays: Monday-to-Friday; and weekends: Saturday-to-Sunday) and two seasons (Summer and Winter) are included. The model therefore represents changes in the supply and demand profiles in 2x2x18 time slices.

Demand profiles are shown in Figure 4 for normalised *useful energy service* demand (only residential shown for brevity). The demand profiles of the other sectors will be included in the supplementary materials and are based on timeseries data from (Dekenah, 2010) and (Eskom & Gildenhuys, 2017). Figure 5 shows the profiles used for solar and wind capacity factor profiles (more details described in section 3.2) derived from the data of (DoE REDIS, 2018) and (CSIR, 2016).

2.2.2 Parameterisation of Flexible Demands as electrical Demand Response in SATIM

All SATIM model equations and technology functional specifications are implemented as in the standard TIMES modelling framework and can be found in the official IEA-ETSAP documentation (IEA-ETSAP, 2018). Flexible demands are modelled here as standard TIMES electrical storage devices, given a maximum combined up and down regulating power capacity determined by the assumed DR penetration level, and a total shiftable amount of energy (time duration).

Increasing percentages of electrical end-use appliances are considered to be flexible in each penetration scenario listed below being fully controllable and capable of responding to DR signals. Each end-use has a maximum of 4 hours of sustained demand response and must balance in a 24-hour period, therefore no demand is left unserved. The DR resources may be called upon to shift their usage at any time of the day.

Three levels of electrical flexible demand penetration are modelled in this study:

1. **0% flexibility** – All electrical demands must provide the exact defined energy service demand profile.
2. **10% flexibility** – 10% of the peak electrical demand per sector are considered fully controllable and flexible including a maximum 4-hour sustained response – all demands must balance and be served within a day.
3. **20% flexibility** –as above but with 20% of electrical demand per sector.

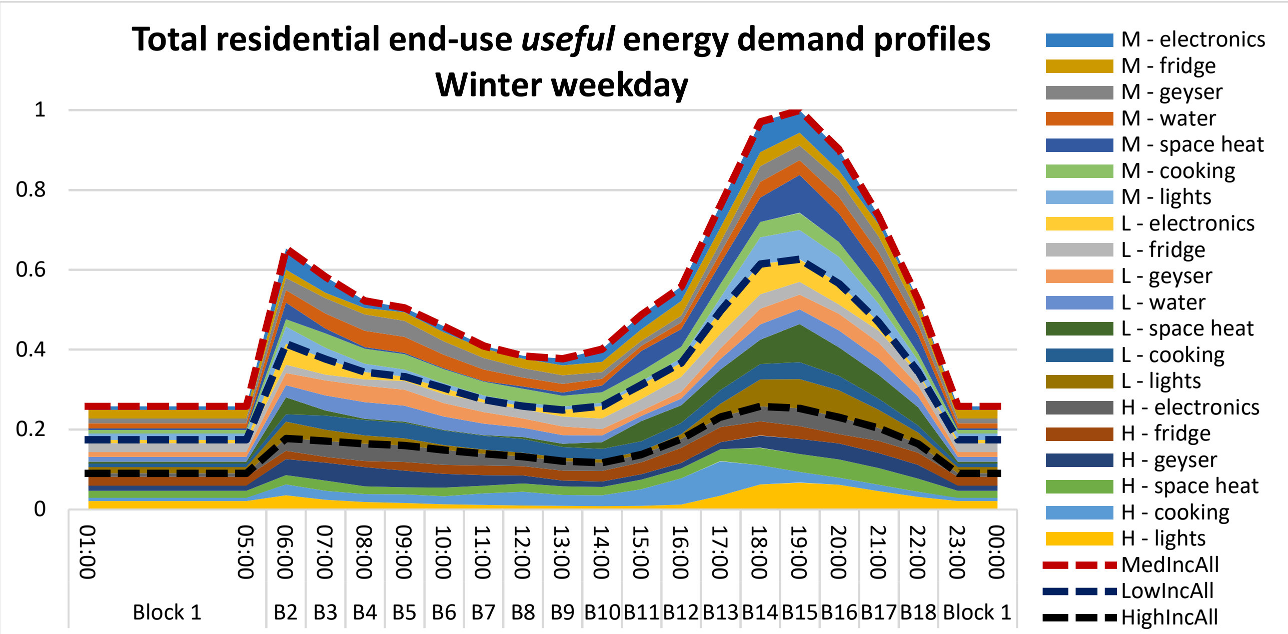


Figure 4: End-use useful demand profile for the residential sector as modelled for a winter weekday in SATIM. H = High income, M = Medium income, L = Low income. Note: show above is useful energy demand (services) – final energy demand (ie. electricity demand is a result of the model supply and appliance optimisation)

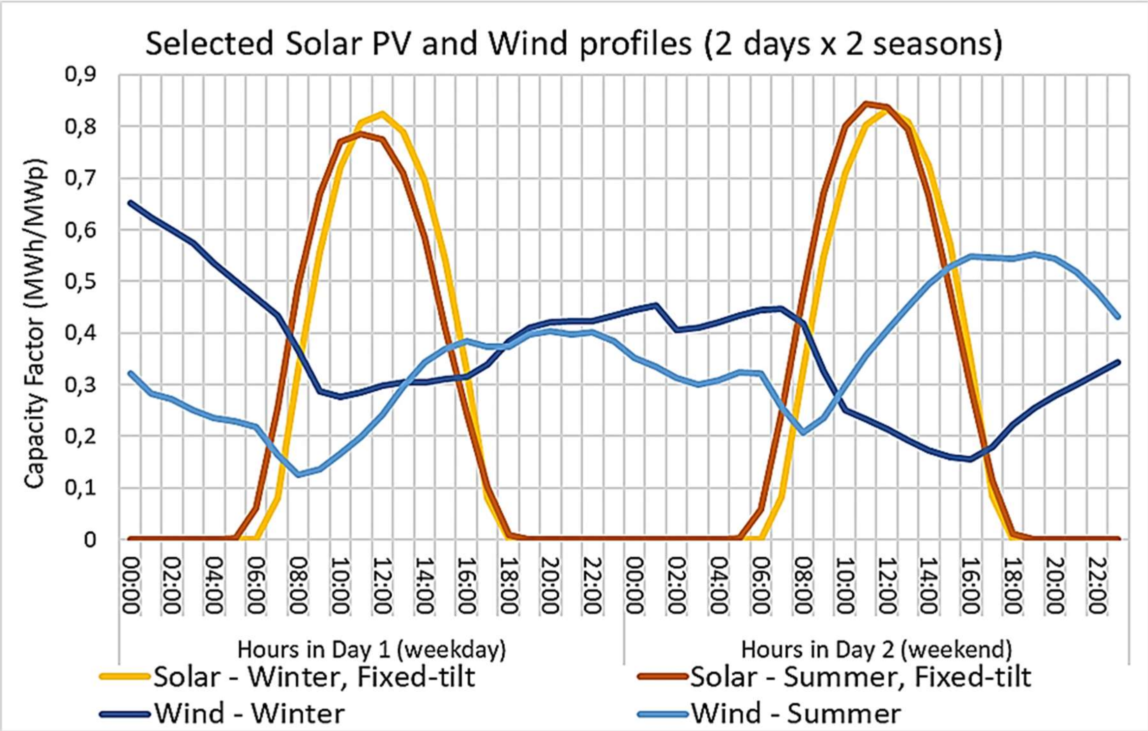


Figure 5: Solar PV and wind generation capacity factor profiles for the representative 2 seasons and 2 days. Base data is derived from (CSIR, 2016) and (DoE REDIS, 2018)

2.3 Current exclusions and limitations of this study

Several aspects have not been explicitly quantitatively included in this study and are briefly detailed below – these are all areas marked for ongoing future work updates.

- Spatial disaggregation: Energy system is modelled as a single node including some aspects of: demand concentration and weather, renewable energy generation, spatially explicit transmission system constraints.
- Climate change, greenhouse gas mitigation, and weather impacts: Increased cooling demand from hotter weather and decreased heating demand, national climate change commitment scenarios and NDCs including their "ratcheting" and possible CO2 taxes, extreme weather events and large inter-annual variations of wind and solar are also currently only represented in aggregate.
- Detailed high resolution electricity system operations and dispatch details are either excluded or represented as an overall reserve margin on and flexible generation backup constraints (described above); these include: reliability and stability testing with low inertia high Rate of Change Of Frequency (RoCF) systems, ancillary services and frequency response, individual plant ramp rates, partial load limits/efficiencies, start-up costs, security constrained unit commitment, day/hour-ahead forecasting and redispatch, detailed electricity tariff structures etc.
- Environmental considerations and constraints such as: water supply infrastructure, emissions standards retrofit requirements/costs for existing and new coal plants, and any other typical externalities.
- Regional power pool hydro power for flexible dispatch and reservoir storage capacity is also not currently included beyond Inga as a supply option as in the 2016 IRP.
- "Power-to-X" incorporation: using electricity to produce hydrogen, "green" liquid fuels production, methanol and acetone etc – as well as using hydrogen as a reductant in iron and steel.

3 Reference Scenario and Baseline

The reference scenario is the modelled least-cost energy system pathway without carbon constraints or caps on centralised renewable energy construction. The power sector is modelled in SATIM and provides a future electricity system build plan determining the optimal timing and quantities of new power sector investments, considering the existing power system and its integration with the larger South African energy system. An outline of key assumptions relevant to this scenario can be found in the following sections.

3.1 Electricity Demand Projections

The demand forecast for this study includes the full South African energy system. The ERC demand projection can be seen in Figure 8 (left) compared to the IRP 2010, IRP 2016, CSIR, and EIUG forecasts. For the electricity sector, this projection is lower than the IRP 2016 (CSIR High-Low Intensity) similar the Energy Intensive Users Group 'EIUG' demand forecast which is also close to the CSIR low demand forecast developed for the IRP 2016 (DoE, 2016, CSIR, 2017, EIUG, 2017). The EIUG forecast was used as is in the Meridian Economics study examining the viability of older Eskom coal plants (Steyn, Burton & Steenkamp, 2017).

3.2 New-build Electricity Generation Technology Assumptions

All new-build conventional technology costs and performance parameters are aligned with the draft IRP 2016 update (based on the independent EPRI report commissioned for the IRP), other than the parameters on nuclear, which were provided by the Department of Energy (DoE, 2016). Conventional generating technology investment options available for the model to use include: new coal, nuclear, gas turbines and engines, and regional hydro. The cost and performance parameters of conventional technologies all remain fixed throughout the model optimisation horizon to 2050.

Starting technology costs for utility-scale solar PV and onshore wind are calculated to align with the recent Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) tariffs, i.e. Bid Window 4.5 (expedited). Between Bid Window 3 and Bid Window 4 (expedited), solar PV and wind prices decreased by 47% and 29% respectively, with both reaching an average of R0.62/kWh (2015 Rand). Only projects with signed PPAs as of May 2018 are included as committed in the baseline build plan.

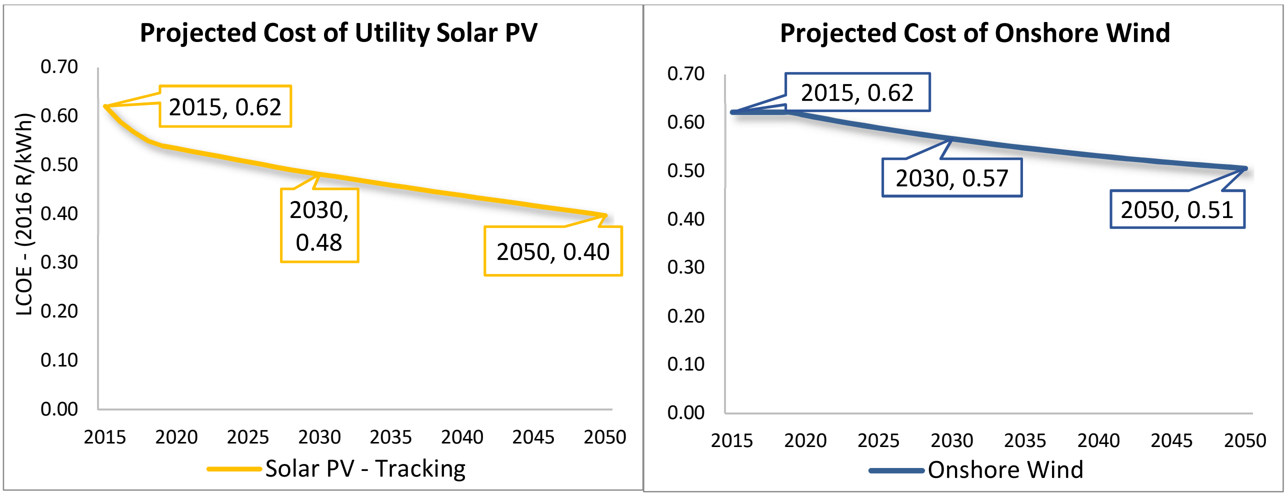


Figure 6: Current and projected levelised costs of solar PV and onshore wind power generation for this study. Levelised costs are shown but not an input into the model – individual technology performance, CAPEX and OPEX components are used as inputs as per assumptions described herein and in (Ireland & Burton, 2018).

Solar PV and wind technology cost reduction projections for the reference scenario ("expected") learning can be seen in Figure 4. No total future resource constraints are imposed for PV or wind, and new capacity can be constructed from 2020 onwards. National wind and PV temporal energy production profiles are based on (CSIR, 2016) and (REDIS, 2018).

Solar PV reference scenario technology assumptions:

- Annual capacity factors are assumed to be 28% using single-axis tracking solar PV technology, and 25% for fixed-tilt. This is based on existing South African plant performance history, using averaged hourly production data from 2015-2017 (DoE REDIS, 2018). Plant life is 25 years, and construction time 1 year.

- Plant cost and performance parameters are modelled to start at calculated 2015 Round 4-expedited REIPPPP values, and improve, using adapted projected rates of change in the latest National Renewable Energy Laboratory (NREL) Annual Technology Baseline (NREL ATB, 2017), UNEP (2015) and Fraunhofer (2015).

Onshore wind reference scenario technology assumptions:

- Annual capacity factors for new onshore wind farms are assumed to start at 36% for plants of size 100MW+ (DoE REDIS, 2018). Plant life is 20 years, and construction time 2 years.
- Plant cost and performance parameters are modelled to start at calculated 2015 REIPPPP values and change using adjusted projected rates of improvement in the 2017 latest NREL Annual Technology Baseline (NREL ATB, 2017), IEA Wind (2018), and Agora Energiewende (2017).

This study includes the assumptions that wind and solar generators are never able to contribute to the peak demand and are fully backed up by firm dispatchable synchronous generators (i.e. zero capacity credit) and with an overall system minimum reserve margin of 15%.

A gas utilisation constraint is imposed in the model with flexible LNG power technologies must run at a minimum annual load factor of at least 10% to account for long term import contract constraints on LNG. Additionally, a minimum limit of flexible thermal generation utilisation is imposed as a 15% share of the sum of variable renewables is enforced in accordance with previous soft-linking and benchmarking of SATIM with high resolution electricity system security-constrained dispatch models as in (Merven & Ireland et al., 2018) adapting the methodology of PLEXOS-TIMES model linking originally presented in (Deane et. al, 2012).

3.3 Reference baseline least-cost future electricity system projection results from SATIM

Figure 7 shows the reference case least-cost optimised future electricity system mix of existing and new-build power plants each decade from 2015 to 2050 - it depicts the total installed peak generating power *capacity* of each technology in the system (left) and the expected *energy* generation shares (right).

South African electricity demand has flattened over the last decade, while large units at Medupi and Kusile are still being added to the grid, resulting in sufficient installed capacity for the medium-term outlook (assuming average existing coal fleet availability is above 70%). Thereafter, as demand grows, and existing coal plants are decommissioned, the least-cost mix of new centralised generation is a combination of wind, solar PV, and flexible coastal LNG generation coming online from 2025.

Figure 8 presents a comparison of the SATIM baseline results against other recent comparable future South African optimal electricity system projections available in the public domain. Left of the figure shows the projected electricity demand forecast comparison with the SATIM forecast similar to the Energy Intensive Users Group (EIUG, 2017). Right of the figure compares the total expected average annual electricity generation shares from non-hydro renewable energy (specifically solar and wind). In a least-cost investment pathway all of these models project a steep increase in wind and solar PV electricity penetration, which is complemented by new flexible LNG generation and the existing coal and hydro resources remaining in the system.

Optimised future build plans include no new coal or nuclear power plants as they are uneconomic against alternatives using the technology assumptions described above. Concentrating Solar Power (CSP) and modern storage technologies (lithium-ion or flow batteries, hydrogen, power-to-X etc.) are also not currently considered least-cost options using present assumptions, however if potential cost declines are realised these technologies could play an important role in the electricity system and diversify or shift the mix of wind, PV and natural gas.

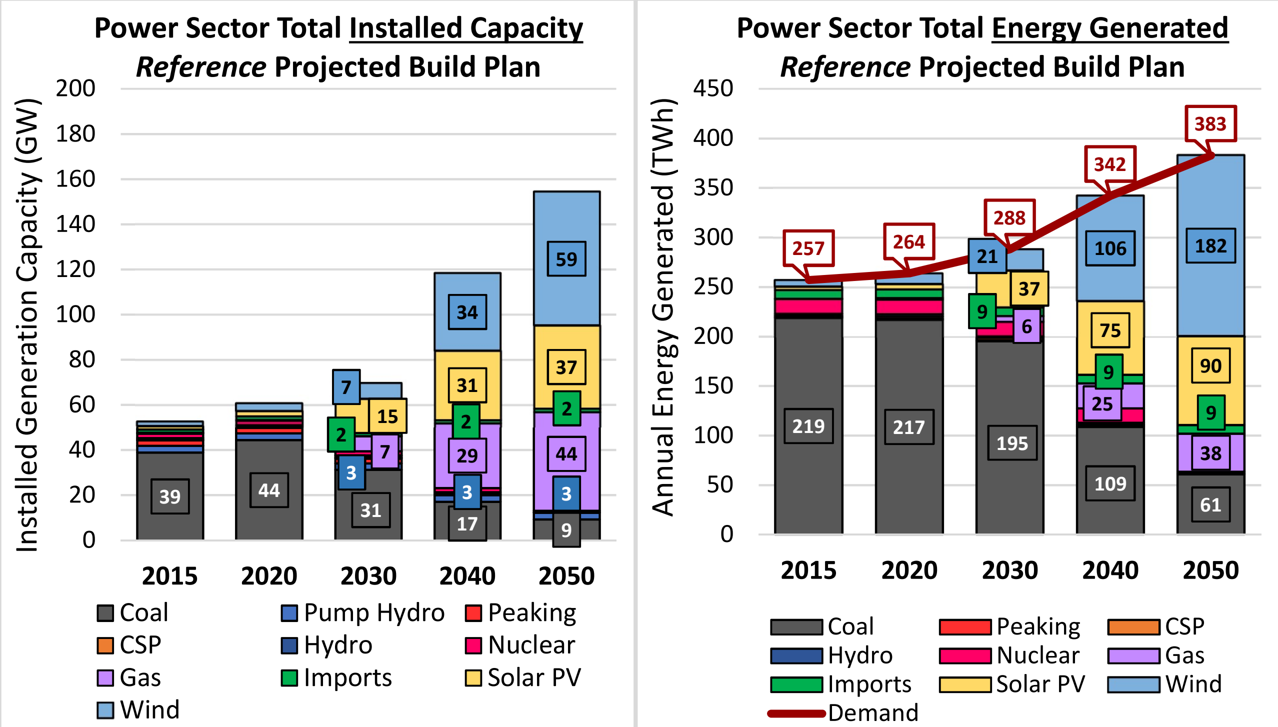


Figure 7: Reference scenario least-cost future capacity expansion plan and expected annual energy generation contributions per generation technology category. Smaller relative contributors do not have individual value labels.

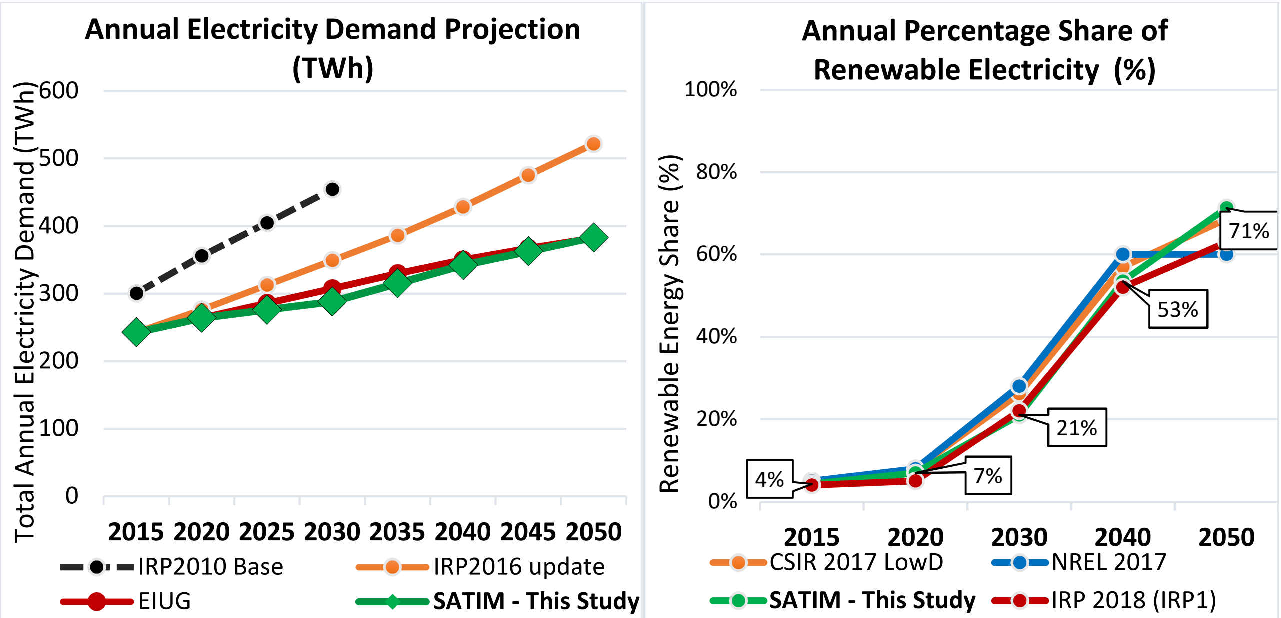


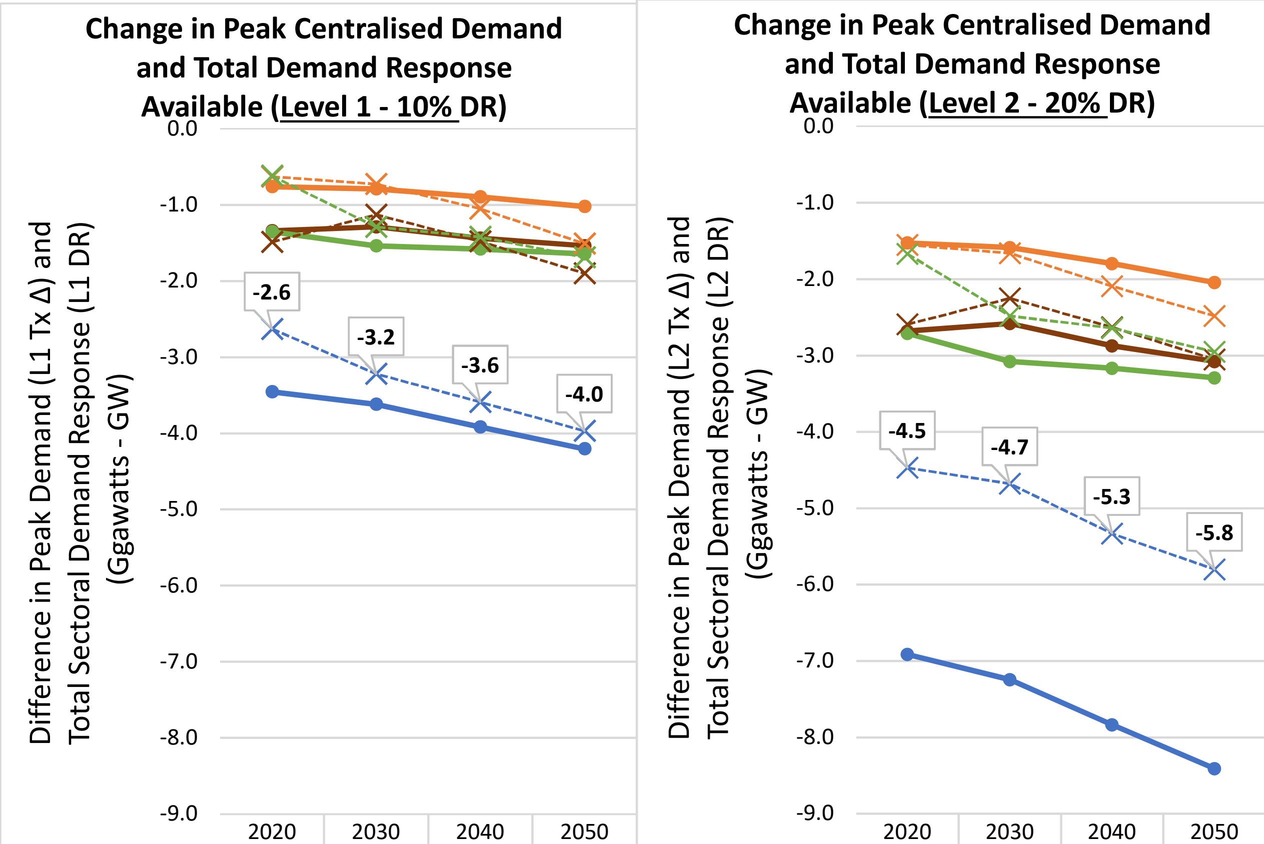
Figure 8: Comparison of baseline SATIM annual electricity demand projections and expected non-hydro renewable energy percentage share contributions per year. SATIM values are compared to (DoE, 2011, 2016, 2018; NREL, 2017; CSIR, 2017; EIUG 2017)

4 Results: inclusion of flexible demand response resources

The key results for the potential system impacts and system value of the inclusion of DR as a flexible distributed energy resource modelled as described above are shown below - the impacts are demonstrated by measuring the resulting differences in least-cost system configuration with FD included compared to the baseline scenario without FD. Results are included for the different sub-sectors modelled individually and together all combined, for both modelled penetration levels of DR (10% and 20% of electric loads), reported from 2020 to 2050 in 10-year milestone increments.

4.1 Total available demand response resources and change in peak electricity grid demand

Shown in Figure 9 for each sub-sector modelled individually in isolation, and all sectors combined, is the total DR resource available at each penetration level and their potential impact on peak electricity grid demand – with Level 1 on the left and Level 2 on the right.



	2020	2030	2040	2050
A - L1 DR	-3.5	-3.6	-3.9	-4.2
C - L1 DR	-0.8	-0.8	-0.9	-1.0
I - L1 DR	-1.3	-1.3	-1.4	-1.5
R - L1 DR	-1.4	-1.5	-1.6	-1.6
A - L1 TxΔ	-2.6	-3.2	-3.6	-4.0
C - L1 TxΔ	-0.6	-0.7	-1.1	-1.5
I - L1 TxΔ	-1.5	-1.1	-1.5	-1.9
R - L1 TxΔ	-0.6	-1.3	-1.4	-1.7

	2020	2030	2040	2050
A - L2 DR	-6.9	-7.2	-7.8	-8.4
C - L2 DR	-1.5	-1.6	-1.8	-2.0
I - L2 DR	-2.7	-2.6	-2.9	-3.1
R - L2 DR	-2.7	-3.1	-3.2	-3.3
A - L2 TxΔ	-4.5	-4.7	-5.3	-5.8
C - L2 TxΔ	-1.6	-1.7	-2.1	-2.5
I - L2 TxΔ	-2.6	-2.3	-2.6	-3.1
R - L2 TxΔ	-1.7	-2.5	-2.6	-3.0

Figure 9: Total Flexible Demand Resources at each penetration level and potential impacts on total electric transmission system peak power demand. Penetration level 1 (left) and penetration level 2 (right). L1 DR = penetration level 1 – 10% flexibility; L2 DR = Level 2 – 20% of loads; TxΔ = difference in peak demand on total power transmission system; A = all demand sectors; C = commercial only; I = industrial only; R = residential only

The solid lines in Figure 1Figure 9 represent the sum of all DR power capacities down-regulation capacity in gigawatts (or "negawatts") for each economic sector, and for all sectors combined. This could be considered the "total DR resource available" and is represented in the figure as a downward regulating resource (negative power demand impact in gigawatts – the resources can also upregulate but is not shown here). The dotted lines in comparison from Figure 9 show the modelled potential impact on total peak centralised grid demand – representing the reduction in required total installed peak generation and transmission capacities. Of key interest here are the differences in results of individual sectors modelled in isolation versus when combined, and the differences between penetration levels demonstrating diminishing returns of larger amounts of DR.

For example, by modelling the commercial sector in isolation (orange lines) there is a greater reduction in total grid demand than the total capacity of DR added in that scenario – this is due to the fact that other sectors such as residential are in fact switching fuels away from electricity to allow a greater peak reduction to complement the reductions in the commercial sector as the residential electrical demands are modelled to remain inflexible. However, when all sectors are combined the total reduction is in fact less than the total DR available – this is due to the peaks of demand in each sector not being co-incident and therefore not all able to fully reduce their demand in the overall system peak period.

On the right of Figure 9 the diminishing returns of additional DR in the system increasing from 10% DR to 20% can be seen by the much larger difference in peak reduction compared to total available DR in that scenario. For example, for all sectors in Level 1 in 2050 a 4.0 GW reduction peak demand is observed from a 4.2 GW DR resource – however, for a 100% increase of the DR resource to 8.4 GW in Level 2 the total reduction only increases by 45% to a 5.8 GW reduction.

4.2 System Value of individual and combined flexible demands

Shown in Figure 10 (left) is the *marginal* stacked potential system value of DR, shown as a R/kWh value of demand shifted, for all sectors individually, and all sectors combined for both penetration levels from 2020 to 2050. What can be seen is the difference in system value from different sectors with the trend showing the residential sector having the highest system value among the sectors, followed by the commercial sector, and finally the industrial sector showing the lowest value in comparison. When DR is modelled together from all sectors the combined system value lies between the highest and lowest sectoral system values. Also demonstrated in the figure is the diminishing return of adding additional flexible demand to the system past the initial 10% penetration. For almost all sectors in all years the result of doubling available flexible demand resources from 10% to 20% of loads the marginal system value of the additional flexible demand is typically less than half of the system value of the initial 10%. Finally what can be observed is that the system value of flexible demand in the system increases significantly from 2020 to 2040 where it stabilises by 2050, due to the system having an overall higher penetration of variable renewable energy and future transmission and distribution infrastructure investment deferral.

Shown in Figure 10 (right) are the *total* expected differences in installed power generating capacity from both DR penetration levels from 2030 to 2050 but only shown for the combined modelled DR from all sectors. The majority of installed generating capacity differences occur as a reduced requirement for LNG capacity starting from 2030. There is also a shift in the optimal mix of wind and solar PV towards including more wind generation in the system however with not as large a shift as observed in natural gas generation differences. The large reduction in LNG generation capacity is due primarily to the reduction in total centralised peak demand as demonstrated earlier as the new LNG generators added with the future new build mix of wind and solar serve the role of peaking and flexibility to complement the solar PV and wind generation which are modelled to have a 0% capacity credit as described above (i.e. they are never able to contribute to the firm dispatchable capacity required to meet the 15% reserve margin above peak demand)

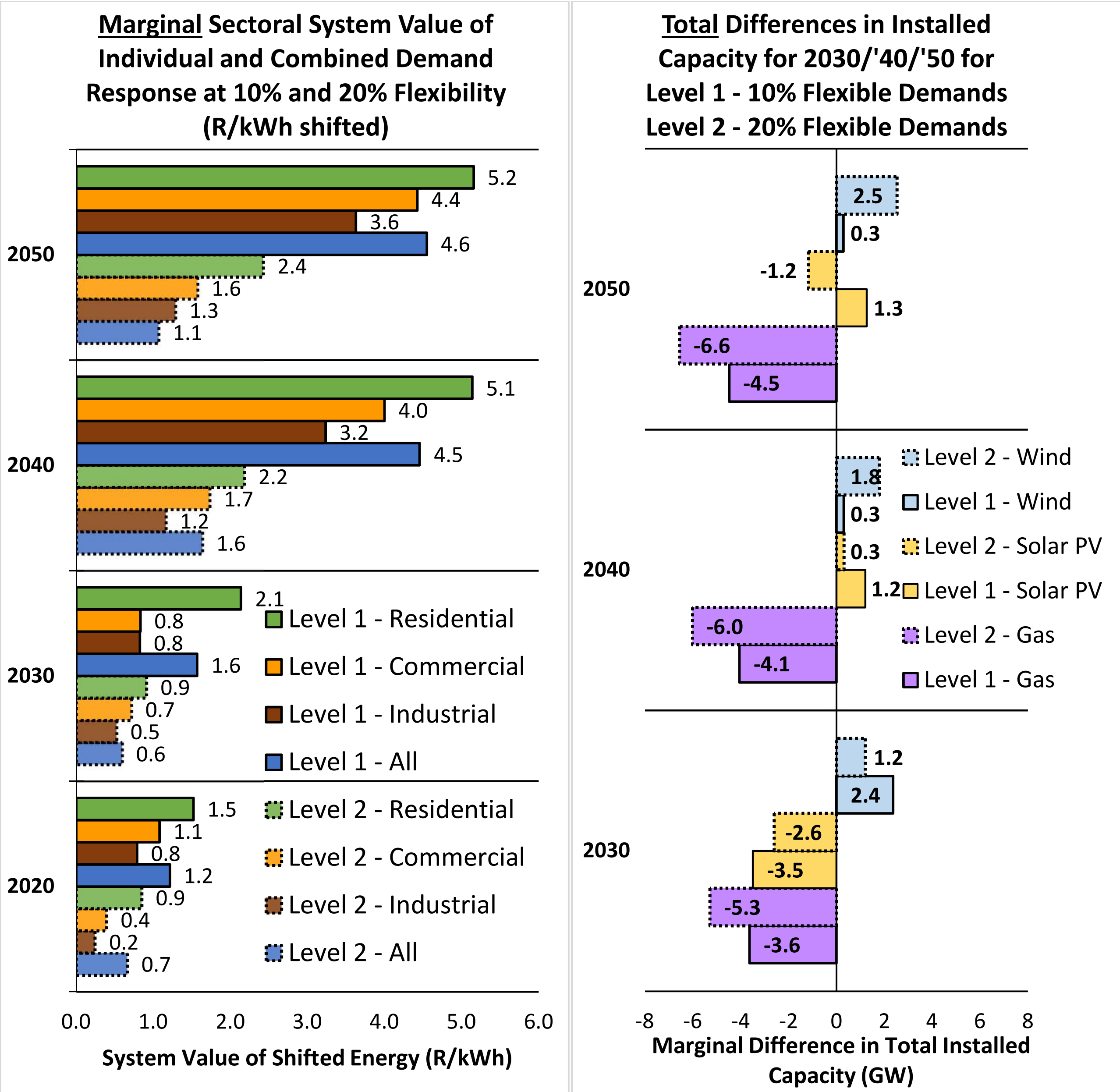


Figure 10: Marginal sectoral and combined system value potential of demand response (left) and total differences in installed power generating capacity between modelled scenarios (right).

5 Conclusions and Future Work

Only after evaluating the expected potential system impacts and value of demand flexibility in the energy system, can justifications be made for large scale DR deployment, participation and incentive program implementations, and inclusion in long-term energy system investment planning policies. A lack of experience in DR programs worldwide and the need for development of accurate system wide modelling representations still causes significant uncertainty of the long-term system value of potential DR programs (US DoE, 2006; O'Connell, 2015; Nolan, 2015; Zerrahn, 2015).

One of the conclusions emerging from international research on energy system flexibility e.g. (JRC, 2015) is that there needs to be a mapping between flexibility needs and best practice for modelling in the context of a rapidly evolving global energy system. The prevailing approach in recent years has been to combine large energy system models to sector-specific models, despite the technical issues and the need to manage trade-offs between model simplicity / coarseness and the accuracy and reliability of model results.

The cost and complexity of DR program implementation will only be justified from a particular energy system participant's or stakeholder's perspective if the achievable combined system benefits are greater than the expected costs of implementation – thus providing a net-benefit to that participant. The true total FD resource potential could then be realised by the market by implementing appropriate DR programs, incentives, and participation rules. These programs could then be designed and managed by each distributor or the transmission system operator depending on their scope of the system and prioritisation of potential FD benefits. Innovations and investments to reduce implementation costs and maximise stacked system value would then be incentivised to maximise the net benefits to the various system participants and ultimately justify the existence of a DR program.

The key results and insights of this study investigating the potential future system impacts and system value of electrical demand response in the South African energy system are summarised as follows:

- Modelling demand sectors in isolation can give inaccurate or incomplete results – individual sectors in isolation can show more than 100% peak reduction as other sectors switch fuels to realise single sector benefits, however when modelled together across all sectors their relative combined impact is reduced.
- Modelling only small amounts of DR does not show the diminishing marginal returns of additional DR resources at higher penetrations as the benefits to the system start to become saturated. The first initial penetration of flexible demand added into a model has the highest system impacts and value as it will be used maximally in the highest impact areas of the system, usually during the peak periods where it will offset the need for the most expensive peaking plants in the system, the overall peak power generating capacity requirement of the system, as well as the total transmission system, and sectoral distribution network capacities.
- The majority of installed generating capacity differences occur as a reduced requirement for LNG capacity starting from 2030. There is also a shift in the optimal mix of wind and solar PV towards including more wind generation in the system however with not as large a shift as observed in natural gas generation differences.
- The system value of DR increases significantly into the future as more variable renewables are added to the system, the replacement of retiring transmission and distribution infrastructure and investment in new capacity can be differed using the "non-wires alternatives" of DR to reduce peak demand and capacity requirements. The observed differences in the reduced requirements for centralised flexible LNG generation also gradually increase from 2030 to 2050.

This study reveals several potential implications for South African national energy system modelling, planning, and policy development for the Integrated Resource Plan (IRP) and Integrated Energy Plan (IEP) of the Department of Energy. It is recommended that the South African IRP includes a greater appreciation and inclusion of more detailed flexible demand and DER representations in the planning process and future energy system investment optimisation process.

The clearest direct impacts to the outcomes of the planning process from the inclusion of DR would be those of the total installed capacity and timing of needed LNG power plants and their resulting import infrastructure and trade requirements. The total installed transmission and distribution system investment requirements and timing could also have notable changes – this would however need to be spatially investigated on a per sector, and per region basis, as for example industry peak demand may actually increase in the middle of the day from strategic load growth allowing the better utilisation of available solar PV production.

The IRP also does not include the potential for fuel switching between electricity and other energy carriers and technologies as alternatives to electricity in meeting energy demands. The IRP electricity system optimisation model is not fully linked and aligned to the IEP model of South Africa which includes demands for non-electrical energy for liquid fuels and industrial processes. Additionally, the electricity demand projections are carried out using double regression and extrapolation of historic demand, estimated future energy intensity changes, and economic and sectoral growth scenarios, which is then used to scale a fixed annual hourly demand profile to meet the total projected demand. This removes the ability to investigate the differentiated energy demand, supply, and distributed energy resource impacts within individual economic sub-sectors – such as the demonstrated differences in sectoral DR impacts shown in this study. The IRP also does not include the expected electricity demand growth of future electric vehicle uptake scenarios and their resulting impacts on electricity demand profiles. Each of these aspects of demand and their flexibility could have significant impacts on the planning process and outputs of the IRP, and their inclusion is thus recommended in future revisions of the IRP and IEP.

5.1 Future Work

The research done here answers some but not of all the questions relating to flexible demand in the South African energy system. The SATIM model used is however an ongoing project and will continually be updated to incorporate ongoing developments in the rapidly evolving global and domestic energy landscapes. Inputs from the scientific community, energy planners, governments, and experience from technology performance and market participation are thus welcomed to improve the ongoing relevance and accuracy of the research presented.

Alternative technology cost scenarios for wind, PV and CSP and fuel costs for natural gas and existing coal plants, as well as GHG emissions constraints will be investigated in future work. Scenarios can include several sensitivities and combinations of different future projections of technology costs and performance of competing technologies such as wind, solar, storage, nuclear, and CSP. Additionally, the impacts of uncertainty in the cost and supply contract flexibility of imported liquified natural gas, imposing economy-wide greenhouse gas emission constraints, as well as different localisation, employment, manufacturing, and innovation potentials of different technologies should be studied.

South Africa's 2018 IRP and NDCs have been rated as "Severely inadequate" (CAT, 2018) for an equitable share in limiting global warming to well below 2° C with calls for significantly more ambitious GHG reductions – therefore an unconstrained reference least-cost case could be considered likely to change to include carbon budgeting or a CO2 tax having significant implications for the power sector. Future work including more scenarios with economy wide carbon constraints and a closer look at fuel switching would thus be important to investigate further. A carbon budget will require a combination of more renewables, reduced coal, and more gas or alternative firm flexible compliments to variable wind and PV. This could increase the value of flexible electric demand response in the system but may also cause sectors to switch fuels away from electricity and implement more aggressive energy efficiency measures to reduce emissions, and thus reducing the total electric demand resource available for exploitation as flexibility. This may be especially true for water heating switching from electric to solar, and industry switching from electric arc furnaces and boilers to natural gas. The opposite may be true of electric vehicles, that in a carbon constrained scenario a higher electric vehicle penetration is required, and thus increasing the total potential flexible demand resources from transportation. It may also cause a switch from coal boilers and chemical processes (such as steel reduction) to electricity or hydrogen given their potential demand response flexibility value.

Using the technology cost and performance assumptions as shown above the modelling has not yet shown the economic stranding of coal generation assets in the model – ie. the combination of new RE and flexibility economically outcompeting and replacing existing coal. Future scenarios which include lower cost long duration storage, faster PV and Wind learning rates, and rising coal cost in the power sector could result in the eventual economic stranding of coal, and thus the additional flexibility provided by DR could accelerate the uptake of variable renewables replacing coal.

Running with the fully linked energy-economic (SATIMGE) could also reveal further insights by modelling and measuring feedback loop impacts on energy demand, GDP, and sectoral employment indicators. This is especially important in GHG constrained system scenarios where more pressure is put onto the economy as a whole resulting in a larger deviation from a pure least-cost system.

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