PyPSA-ZA: Investment and operation co-optimization of integrating wind and solar in South Africa at high spatial and temporal detail

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Abstract

South Africa is in the fortunate position of having access to high-quality wind and solar resources promising energy production costs well below the ones projected for future installations of thermal generation; yet the feasibility of a low carbon energy system is still under scrutiny. This study introduces a spatially and temporally resolved techno-economic model co-optimising generation and transmission capacity investments and operation. 27 supply regions in South Africa are equipped with a year of time-series in hourly resolution based on the IRP2016 base-case assumptions. Six different scenarios representing different restrictions on renewable generation and mitigation efforts of GHG emissions are evaluated and discussed. 70% of energy from renewable sources were found to be cost-optimally integrated using flexible gas generation and the expansion of several transmission corridors. A 95% CO_2 reduction leads to a moderate 20% cost increase. The open-source nature of the model and restriction to freely available data encourages an accessible and transparent discussion about the future South African energy system, primarily based on renewable wind and solar resources.

Keywords: Electricity system model, renewable power generation, transmission networks, least-cost optimisation, open source.

1. Introduction

South Africa was attested high-quality wind and solar resources with potential for very high load factors and a weak seasonality that simplifies their integration into the electricity system [1]. Several GW of solar PV capacities can be integrated without major restructuring of the electricity

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grid [2, 3]. Nevertheless, the latest Integrated Resource Plan by the South African Department of Energy (DOE) proposes only a slow uptake of renewable energy sources and bases its electricity plan on new Nuclear and Coal power stations [4, 5]. Meanwhile, South Africa pledged to reduce its GHG emissions starting from at latest 2025, and the electricity sector is an easy target.

This paper presents a spatially and temporally resolved model for performing least-cost techno-economic investment and operation optimisations of the South African electricity system. In 27 supply regions the hourly demand in the reference year 2040 has to be met by existing Coal, Nuclear or Hydro generation capacities or by generation from new open-cycle or closed-cycle gas turbines, coal plants, nuclear reactors, wind turbines or solar PV panels. The shape of the demand time-series as well as of renewable generation availability derive from historical load and weather data exhibiting the actual spatio-temporal correlations. The technology portfolio is complemented by battery storage and pumped hydro storage. The model is exlusively based on freely available data and open technologies.

In Section 2 and 3 the data sources and processing methods are presented; the optimisation results are presented in Section 4; limitations of the model are discussed in Section 5; conclusions are drawn in Section 6.

2. Methods: Model

This study models a future, renewable South African electricity network geared towards forecasts of the reference year 2040. The PyPSA framework underlying the PyPSA-ZA model implements a partial equilibrium model optimising both short-term operation and long-term investment in the energy system as a linear problem using the linear power flow equations [6, 7]. It determines the optimal generation fleet to serve hourly electricity demand in the reference year. The intermediate build-up steps from today to 2040 are not assessed.

2.1. Objective function

The model minimises the total annual system costs as

$$\min_{\substack{G_{n,s},F_\ell, \\ g_{n,s,t},f_{\ell,t}}} \left[\sum_{n,s} c_{n,s}G_{n,s} + \sum_\ell c_\ell F_\ell + \sum_{n,s,t} o_{n,s}g_{n,s,t} \right], \qquad (1)$$

and consists of the capacities $G_{n,s}$ at each bus n for generation and storage technologies s and their associated annualized fixed costs $c_{n,s}$, the dispatch $g_{n,s,t}$ of the unit at time t and the associated variable costs $o_{n,s}$. Further, the branch capacities F_ℓ for each branch ℓ and their annualized fixed costs c_ℓ are also included. The branch flows $f_{\ell,t}$ do not contribute to the total costs. The optimisation is run over all hours t in a year with varying weather and demand conditions.

2.2. Generator constraints

The dispatch of conventional generators $g_{n,s,t}$ is constrained by their capacity $G_{n,s}$

$$0 \leq g_{n,s,t} \leq G_{n,s} \qquad \forall\, n, s, t \ . \tag{2}$$

The dispatch is limited by ramp rate constraints $ru_{n,s}$ and $rd_{n,s}$ per unit of the generator nominal power[1],

$$-rd_{n,s}\, G_{n,s} \leq (g_{n,s,t} - g_{n,s,t-1}) \leq ru_{n,s}\, G_{n,s} \ . \tag{3}$$

The maximum producible power of renewable generators depends on the weather conditions, which is expressed as an availability $\bar{g}_{n,s,t}$ per unit of its capacity:

$$0 \leq g_{n,s,t} \leq \bar{g}_{n,s,t} G_{n,s} \qquad \forall\, n, s, t \ . \tag{4}$$

The power capacity $G_{n,s}$ is also subject to optimization up to a maximum installable potential $\bar{G}_{n,s}$ restricted by available geographic area:

$$0 \leq G_{n,s} \leq \bar{G}_{n,s} \qquad \forall\, n, s \ . \tag{5}$$

2.3. Storage operation

The energy levels $e_{n,s,t}$ of all storage units have to be consistent between all hours and are limited by the storage energy capacity $E_{n,s}$

$$e_{n,s,t} = \eta_{n,s,0} e_{n,s,t-1} + \eta_{n,s,+} \left[g_{n,s,t} \right]^{+} - \eta_{n,s,-}^{-1} \left[g_{n,s,t} \right]^{-} + g_{n,s,t,\text{inflow}} - g_{n,s,t,\text{spillage}} \ , \tag{6}$$

$$0 \leq e_{n,s,t} \leq E_{n,s} \qquad \forall\, n, s, t \ . \tag{7}$$

Positive and negative parts of a value are denoted as $[\cdot]^{+} = \max(\cdot, 0)$, $[\cdot]^{-} = -\min(\cdot, 0)$. The storage units have a charging efficiency $\eta_{n,s,+}$, a discharging efficiency $\eta_{n,s,-}$, in-flow (e.g. river in-flow in a reservoir) and spillage. The energy level is set to be cyclic, i.e. $e_{n,s,t=0} = e_{n,s,t=T}$.

2.4. Power balance and transmission constraints

The (inelastic) electricity demand $d_{n,t}$ at each bus n must be met at each time t by either local generators and storage or by the flow $f_{\ell,t}$ from a transmission line ℓ

$$\sum_{s} g_{n,s,t} - d_{n,t} = \sum_{\ell} K_{n\ell}\, f_{\ell,t} \quad \leftrightarrow \quad \lambda_{n,t} \qquad \forall\, n, t \ , \tag{8}$$

where $K_{n\ell}$ is the incidence matrix of the network and $\lambda_{n,t}$ is the marginal price at the bus. This equation implements Kirchhoff's Current Law (KCL).

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[1]Currently only implemented for existing Coal power stations.

For the physicality of network flows, additionally Kirchhoff's Voltage Law (KVL)

$$\sum_{\ell} C_{\ell c} x_\ell f_{\ell,t} = 0 \qquad \forall c, t \ , \tag{9}$$

expressed with a cycle basis $C_{\ell c}$ and the series inductive reactance x_ℓ must be enforced [8].

The flows in all branches are constrained by their capacities F_ℓ

$$|f_{\ell,t}| \leq F_\ell \qquad \forall \, \ell, t \ . \tag{10}$$

Since the expansion of line capacities F_ℓ representing the addition of new circuits leads to decreasing line impedances x_ℓ, Equation 9 introduces in principle a bilinear coupling. We maintain the linearity and therefore computational speed by solving the optimisation problem with fixed impedances x_ℓ, updating them and re-solving in up to 6 iterations to ensure convergence, following the methodology of [9].

2.5. CO₂ emission constraint

CO_2 emissions in the *CO₂-Limit* scenarios are limited by a cap $\text{CAP}_{CO2} = 10 \, \text{MtCO}_2$ corresponding to a 95% reduction from today's emissions by the electricity sector, implemented using the specific emissions e_s in CO_2-tonne-per-MWh of the fuel s and the efficiency $\eta_{n,s}$ of the generator:

$$\sum_{n,s,t} \frac{1}{\eta_{n,s}} g_{n,s,t} \cdot e_s \leq \text{CAP}_{CO2} \quad \leftrightarrow \quad \mu_{CO2} \ . \tag{11}$$

μ_{CO2} is the shadow price of this constraint.

3. Methods: Data

3.1. Network topology

The South African transmission grid has been divided into 27 supply areas. They abstract underlying network topology to deliver electricity to between 0.1 and 7 million people each. The capacities necessary to connect them strongly depend on the future layout of generation capacities in South Africa and is ideally optimised jointly. The simplified network model shown in Figure 1 consists of one bus in each supply area located at the centroid of the geographical area[2] and transmission lines connecting all adjacent areas. The lines are modelled as standard overhead AC lines with length of 1.25 times geodesic distance and the electrical parameters of a typical 380 kV-line [10]. The current inter-area transmission capacities have

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[2]The buses for the supply areas NAMAQUALAND and PRETORIA have been moved slightly away from the centroid back into the area.
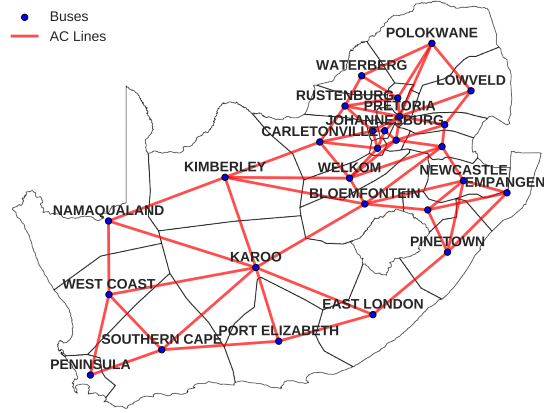
Figure 1: Network model. 27 supply areas as buses. Adjacent supply areas have been connected with typical 380 kV-lines.

been determined by summing the capacities of all transmission lines above and including 275 kV of the Electricity Transmission and Distribution Grid Map (2017) dataset by the World Bank Group [11]. The model may add line capacities between all directly adjacent supply regions.

3.2. Electricity demand

The shape of the electricity demand as an hourly aggregated time-series for the four years 2009-2013 was provided by ESKOM [12] and was scaled linearly to the total yearly electricity demand forecast of 428 TWh in the high demand base case of the Integrated Resource Plan 2016 (IRP2016) by the Department of Energy [4]. The year 2012 was extracted from the time-series and distributed to the 27 buses in proportion to population in each supply area, as determined by aggregation of the South African population density published by World POP [13].

3.3. Existing power stations

The currently existing power stations in South Africa have been compiled from Eskom holdings [14] listed online and the IRP2016 [4]. It is expected that of these 51 GW generation capacities by the reference year 2040 about half will have decommissioned save for 19.9 GW of coal stations, 0.7 GW of hydro reservoir stations, 2.9 GW of pumped hydro storage and the Koeberg Nuclear power station with 1.86 GW. The remaining power plants are attached at the bus of their supply area with marginal and capital costs taken from their fixed and variable operation and maintenance costs plus fuel costs. Additionally, the Cahora Bassa reservoir station in Mozambique which has an installed capacity of 2.075 GW is attached as a 1.5 GW hydro

reservoir station at the POLOKWANE supply area where the two HVDC lines from the dam end in South Africa.

Pumped storage units as well as hydro reservoirs receive a weather dependent hydro-electric in-flow. The re-analysis weather dataset CFSv2 by the US National Oceanic Atmospheric Administration [15] provides water run-off on a 0.2 x 0.2 deg. spatial raster ($x \in \mathcal{X}$) in hourly resolution since 2011. Following the methodology in [16, 17], we aggregated the total potential energy at height h_x of the run-off data $\mathcal{R}_x$ in South Africa as well as in Mozambique c as a simple proxy to their hydro-electric in-flow time-series

$$G_c^H(t) = \mathcal{N} \sum_{x \in \mathcal{X}(c)} h_x \mathcal{R}_x(t) \tag{12}$$

where $\mathcal{N}$ is chosen so that $\int_t G_c^H(t)\,\mathrm{d}t$ matches the EIA annual hydroelectricity generation [18]. The in-flow is distributed to all run-of-river and reservoir capacities in proportion to their power capacity.

3.4. Expandable power generation

The existing generation and storage capacity at full availability amounts to 26.8 GW, barely half the peak load of 62.3 GW; opening the possibility to a large-scale restructuring of the generation technology mix. The model can build wind turbines and solar panels within restrictive landuse limits and open cycle and closed cycle gas turbines (OCGT/CCGT), nuclear reactors and coal power stations at suitable locations and battery storage units at every bus.

3.4.1. Wind and solar PV generation

The per-unit availability time-series $\bar{g}_{n,s,t}$ for wind and solar photovoltaics for each supply region in the year 2012 have been calculated within the Wind and Solar PV Resource Aggregation Study for South Africa [1]. Re-analysis wind speeds of the Wind Atlas for South Africa (WASA) [19] were converted to available wind power feed-in for a capacity layout based on a selection of five representative turbines suitable for low to high wind speeds. Solar PV feed-in has been generated using satellite-imaging based global irradiation with the SODA model [20] for fixed tilted PV installations.

For the estimation of maximal installable wind and solar PV generation capacities $\bar{G}_{n,s}$, we determine the available area A_n in each supply region by restricting to landuse types "Grassland", "Low Shrubland" and "Bare none vegetated" in the South African National Land-Cover Dataset [21] that are not part of protected or conservation areas in [22, 23]. 80% of this area is split equally between wind and solar PV installations, leading to

$$\bar{G}_{n,w} = 0.5{\cdot}0.8{\cdot}10\,\mathrm{MW/km^2}{\cdot}A_n\ , \qquad \bar{G}_{n,s} = 0.5{\cdot}0.8{\cdot}33\,\mathrm{MW/km^2}{\cdot}A_n\ , \tag{13}$$

where $10\,\mathrm{MW/km^2}$ and $33\,\mathrm{MW/km^2}$ are the technical potential densities of wind and solar PV respectively [1]. The factor 0.8 was chosen so that

these simplified assumptions applied to the renewable energy development zones (REDZ) [24] alone lead approximately to the same available area of $53.4 \cdot 10^3 \, \mathrm{km}^2$ reported by the detailed evaluation of the resource aggregation study.

Since the resulting renewable potentials overshoot the demand requirements by an order of magnitude, we evaluate in the following two different scenarios, in the *REDZ* scenario renewable expansion is only allowed in the REDZ areas [24], and a largely unrestricted scenario *CORRIDORS* where the area is confined along the main transmission corridors defined by [25].

3.4.2. Storage

In addition to the pumped hydro storage installed today, the model may build battery storage units at every bus. Their charging and discharging efficiencies, as well as cost assumptions for their power and energy storage capacities are taken from [26]. It is assumed that the charging and discharging power capacities of a unit are equal, and the energy capacity $E_{n,s} = \bar{h}_s \cdot G_{n,s}$ is proportional to this power capacity. The factor $\bar{h}_s$ determines the time for charging or discharging the storage completely at maximum power, and is set to $\bar{h}_s = 3 \, \mathrm{h}$.

3.4.3. Non-renewable generation

The model contains four different types of expandable fossil fuel generators: OCGT and CCGT can be build at Saldana Bay, Richards Bay and Coega, nuclear reactors are installable at Thyspunt and Koeberg and new coal capacities can be added in Waterberg. In the *CO_2 limit* scenarios their usage is subject to the CO_2 cap of Equation 11, while in the *Emission prices* scenarios their marginal costs include externality costs for specific emissions. The *business-as-usual (BAU)* scenario enforces the construction of at least $10 \, \mathrm{GW}$ of nuclear and coal capacities, each, in line with current energy plans. The *Redundant* scenario ensures that peak demand plus a 10% reserve margin can be covered by conventional generators alone.

3.5. Cost assumptions

Investment, fixed and variable operation and maintenance (FOM and VOM) costs and fuel prices and efficiencies for all assets are listed in Table 1. They mirror the IRP2016 draft, except for the overnight capacity costs for the renewable technologies and battery storage [4]. The CSIR calculated the capacity costs for Wind and Solar by de-annualizing the winning bids in the Renewable Independent Power Producer (REIPP) Procurement Programme in 2016 *(check!)* as a dependable proxy to today's installation costs to $13.25 \, \mathrm{R/MW}$ for onshore wind and $9.24 \, \mathrm{R/MW}$ for photovoltaics [26]. BNEF forecasts a reduction of the levelized cost of electricity of PV by 2/3, by 1/2 for onshore wind and by 3/4 for lithium-ion batteries in respect to the reference year 2040 [27]. As a conservative estimate, the proposed capacity

Quantity	Capital costs				Marginal costs		
	Overnight cost [R]	Unit	FOM [%/a]	Lifet. [a]	VOM [R/MWh$_{el}$]	Fuel cost [R/MWh$_{th}$]	Effic.
Wind	10000	kW$_{el}$	4	20			
Solar PV	6000	kW$_{el}$	2	25			
OCGT	8173	kW$_{el}$	2	30	2.4	540	0.31
CCGT	8975	kW$_{el}$	1.8	30	22	540	0.49
Coal	35463	kW$_{el}$	2.6	30	80	98	0.37
Nuclear	60447	kW$_{el}$	1.6	60	37	29	0.34
Battery stor.	12000	kW$_{el}$	2.5	20	3.2		0.89
Transm. lin.	6000	MWkm	2	40			

Table 1: Capital and marginal costs of extendable components

costs in this paper reflect half of this reduction potential, while discussing the full projected interval in Section xxx. For the annualisation of overnight costs a discount rate of 8% is used. The transmission investment of a line with length l_ℓ is $6000\,\text{R/MWkm} \cdot l_\ell f_{n-1}$ with an $n-1$ security factor $f_{n-1} = 1/0.7$.

In the *Emission prices* and *CO₂ limit* scenarios the minimized objective additionally includes the externality costs for specific emissions as referenced in the Integrated Energy Plan by the DOE: $0.27\,\text{R/kgCO}_2$, $7.6\,\text{R/kgSO}_2$, $4.5\,\text{R/kgNO}_x$, $41.5\,\text{R/tHg}$ and $11.3\,\text{R/kgPM}$ (particulate matter) [28]. Since the prices are dual to emission caps, in the *CO₂ limit* scenarios the CO₂ price is omitted from the optimization.

4. Model results

The model is optimized for eight different scenarios. The base case at market costs, two different emission mitigation scenarios by emission prices and 95% CO₂ reduction cap. For each of these, we compare one scenario with renewable generators constrained to *REDZ* and another one with the whole transmission *CORRIDORS* available. Additionally, a business-as-usual scenario with forced coal and nuclear and another one with redundant conventional generators for maximal security are presented.

The externality costs of the IEP2016 introduced in Section 3.5 turn out to solely replace 3 percentage points of demand generated in coal power stations with energy from wind turbines, and are thus mostly ineffective for the mitigation of emissions. Nevertheless, the energy mix of these least-cost solutions shown in the left half of Figure 2 is already strongly based on renewable sources with 57% wind and 13% solar PV, while at the same time being independent of new storage units. Instead the varying in-feed of the renewable sources is balanced by 22 GW of flexible open-cycle gas turbines, supplying a mere 2.5% of demand. If the renewable generators can also be
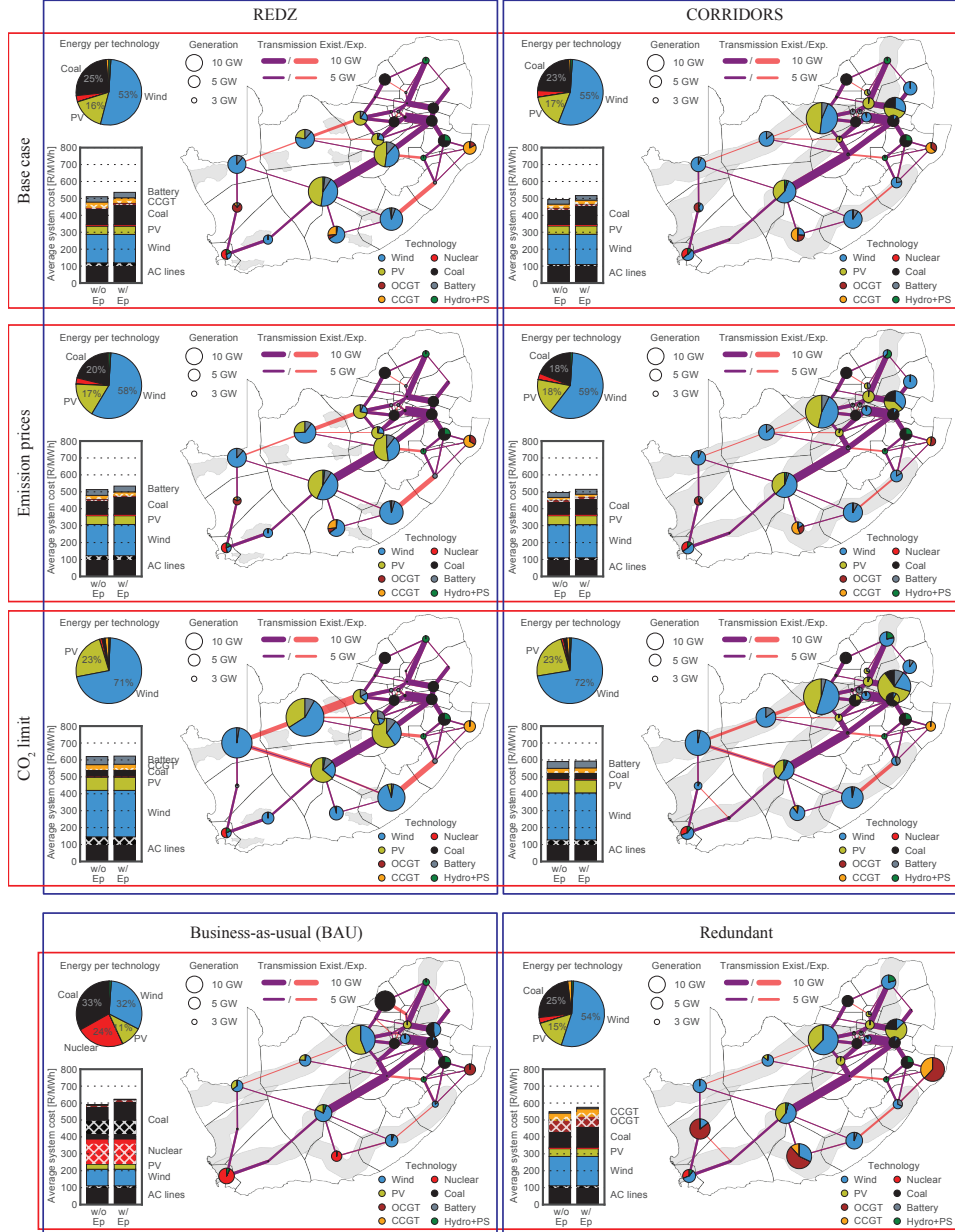
Figure 2: Matrix of scenario results. For each scenario, the top-left pie-chart shows the mix of generated energy, the bar-charts decompose the cost per MWh into the technologies, the map shows the distribution of generation, storage and existing and expanded transmission capacities. The bar-charts show costs with and without externality costs by emissions and separate the cost for new transmission and conventional generation capacities with white xx hatches. The light gray map background highlights the areas available for renewable installations (before landuse restrictions) in the *REDZ* and *CORRIDORS* scenarios (see Sec. 3.4.1). The *Base case* at the top optimizes at market costs, while the *Emission prices* and *CO₂ limit* scenarios include externality costs by emissions (see Sec. 3.5). In the *CO₂ limit* scenarios there is a strict $10\,\text{MtCO}_2$ cap (see Sec. 2.5). The *BAU* scenario enforces $10\,\text{GW}$ of nuclear and coal generation capacities, while the *Redundant* scenario covers peak demand and a reserve margin with conventional generators (see Sec. 3.4.3)

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distributed to the eastern part of South Africa (within the *CORRIDORS*), the additional geographical smoothing by long distances allows to integrate 2 percentage points more wind energy with only 18.5 GW OCGT. The cost per MWh lie between 650 R and 630 R.

A deep decarbonisation to a 95% CO_2 reduction increases the model costs by about 20%. The shadow price μ_{CO2} to the CO_2 emission constraint from Equation (11) captures the linear sensitivity of the total system cost to the CO_2-cap. Its value $2690 - 2770$ R/tCO_2 gives an indication of the CO_2-price equivalent to the cap, which is 10 times the value assumed in IEP2016.

The main cost driver in the CO_2-Limit scenarios is the provision of flexibility for integrating 97% of varying renewable generation: In the *REDZ* scenario additional transmission capacities and CAES account for a cost increase by 90 R/MWh, while the remaining 45 R/MWh are due to a renewable capacity over-installation with about 19% of curtailment. This hints at a great potential for coupling to the other energy sectors, and indeed preliminary results from including a passenger transport sector based on battery electric vehicles suggest that their batteries can replace the expensive CAES units entirely.

The 3hr-batteries already available to the present version of the model are not built, even though their marginal costs and efficiency are superior at similar capital costs relative to power capacity; energy storage capacity is evidently more important.

Lifting the confinement of renewable generation from *REDZ* to *CORRIDORS* reduces the costs for CAES and AC lines by 20 R/MWh each. The need for flexibility reduces and generation is brought closer to load centres around Johannesburg requiring less transmission expansion.

The hotspots for transmission expansion are relatively stable across all scenarios, the most important lines are the new connection between EAST LONDON and PINETOWN in the South East ($10 - 13$ GW in the *CO_2-Limit* scenarios) and lines from NAMAQUALAND and KIMBERLEY in the North-West to the well-connected load-intensive central eastern South Africa around Johannesburg, also making use of the current grid backbone to PENINSULA passing through KAROO.

5. Critical Appraisal

There are a number of simplifications in the modelling presented here that may affect the conclusions.

Available data on the electricity demand time series is not spatially disaggregated; assuming, as we have done, that the load time series shape and demand growth is the same at each node ignores local differences.

Information on the storage capacity of existing hydro reservoir dams was not available and assumed to be 20.6 hrs like the average pumped hydro stor-

age capacity. In-flow time series are based on country-wide approximations, ignoring local topography and basin drainage; in principle a full hydrological model should be used.

The network is represented by standard transmission lines between 27 zones in a single voltage layer. Grid upgrades to prevent intrazonal congestion in the transmission and distribution networks and between them can not be assessed within the model.

Only a single year (2012) has been modelled, so the model may be over-fitting to characteristics of this particular year.

Additional aspects, such as reserve power, stability, transmission losses, efficiency savings, demand side management and sector-coupling have not been considered.

These issues will be addressed in forthcoming studies.

6. Conclusions

In this paper the techno-economic model PyPSA-ZA has been presented that optimises investment and operation costs of the South African electricity system with 27 buses in hourly resolution. Its focus lies on deep decarbonisation scenarios.

By treating operations based on the linear power flow endogeneously, a significant cost reduction potential from improved coordination within the electricity system is uncovered, especially to the benefit of varying renewable energy sources. Solutions integrating a 70% share of renewables were found to be cost-optimal with flexible gas generation and by developing new transmission corridors between EAST LONDON and PINETOWN and from the resource-rich North-western supply regions. A 95% CO_2 reduction relative to today's emission levels is achievable within the model assumptions by a moderate 20% increase in cost.

The model builds exclusively on freely available data and open technologies making it suitable for an iterative and collaborative improvement by many stakeholders. We hope that it will contribute towards a transparent discussion of the future needs of the South African and Southern African energy system.

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