An optimal mix of solar PV, wind and hydro power for a low-carbon electricity supply in Brazil

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Abstract

Brazil has to quickly expand its power generation capacities due to significant growth of demand. Government plans aim at adding hydropower capacities in Northern Brazil, additional to wind and thermal power generation capacities. However, new hydropower may affect environmentally and socially sensitive areas in the Amazon region negatively while thermal power generation produces greenhouse gas emissions. We therefore assess how future greenhouse gas emissions from electricity production in Brazil can be minimized by optimizing the daily dispatch of photovoltaic, wind, thermal, and hydropower plants. Using a simulation model, we additionally assess the risk of loss of load. Results indicate that at doubled demand, only 2% of total power production has to be provided by thermal power plants. Existing reservoirs of hydropower plants are sufficient to balance variations in renewable electricity supply at an optimal mix of around 37% of PV, 9% of wind, and 50% of hydropower generation. In a hydro-thermal only scenario, the risk of deficit increases tenfold, and thermal power production four-fold. A sensitivity analysis shows that the choice of meteorological data sets used for simulating renewable production affects the choice of locations for PV and wind power plants, but does not significantly change the mix of technologies.

Keywords: Brazil, greenhouse gas emissions, photovoltaic, wind, optimization

Introduction

Rising demand of electricity consumption in Brazil at historically 4% per year in the decade 2004-2013 is projected to continue by around 4.2% annually up to the year 2022. The generation capacity therefore has to be expanded rapidly [1]. There are many options for capacity expansion: there is still untapped hydropower potential in the North of Brazil, wind-power resources are also significant, particularly in the North-East and South region, thermal power production may be a valid source due to the recent discovery of hydrocarbons, and solar irradiation for photovoltaic installation is, depending on the region, among the highest globally. Historically, hydropower production dominates the portfolio with 69% to 84% of production coming from that source in the decade 2004-2013 [2]. A further increase of hydropower production is projected up to 2018 and partly under construction already. The lion share of 18.4 GW of that expansion is going to take place in the North of Brazil, while the other regions are only expanding a total of around 1 GW. Planned expansions of around 20 GW after 2018 are also, to a large extent, located in the North of Brazil. Most future projects are therefore located within the Amazon forest and may negatively affect local populations [3] as well as have negative impacts on the ecosystem in place [4]. Additionally, operational risks of the hydro-thermal system may be further increased due to the large hydrological variability – and the high seasonality of rainfall in Brazil. As most projects do not contain new reservoirs, but are operated as run-of-the-river river plants, the seasonal and multi-annual match of supply and demand by managing existing reservoirs is getting much more complicated. Furthermore, the expansion of hydropower in the Amazon region may reduce regional rainfalls due to deforestation. The projected production levels may therefore not be attained, thus making the projects economically less viable [5].

Recently, wind power also entered the production matrix due to significant wind resources, principally in the North-East and South Region of the country. The seasonal complementarity of wind and hydro resources has been shown before [6] and may help in better dealing with hydrological variability. Thermal capacity is, however, planned to be also increased by 5 GW up to 2022 to be better able to deal with the intermittency from wind power and the hydrological variability. From 2020 on the energy sector as a whole may become the most important emitter of greenhouse gases in Brazil, replacing the land use sector which shows decreasing emissions due to successful measures against deforestation. Brazil will show increasing trends in total emissions due to emission from the energy sector by then [7]. Decreasing emissions from electricity generation, additional to measures in decreasing emissions from energy use in transportation, industry, and the buildings sector, may help in lowering Brazilian total greenhouse gas emissions.

Wind and solar power may be alternatives to hydropower. Wind power production is already expanding at high rates due to very good wind conditions at some locations in Brazil, thus allowing low production costs. Up to today, only 890 MW of solar PV was contracted in official auctions[8] , although at many spots in Brazil, solar irradiation is among the highest in the world [9]. The large scale integration of intermittent renewables is often considered to be limited due to the intermittent nature of the sources. Restrictions in the electrical grid, the storage capacity, and thermal backup capacities pose an upper bound on the level of renewables that may be deployed [10]. At the same moment, the Brazilian system is very flexible to accommodate sources of intermittent power production due to large hydro-reservoirs that may be used for regulation [11] and due to the existence of a far reaching transmission grid that may allow to connect different locations for intermittent renewable energy production, thus reducing output variance [12].

A series of studies have investigated the potentials of including wind energy in the Brazilian energy matrix [6,13–15]. They show that seasonal complementarity between hydro and wind resources is given, i.e. wind resources in the North-East of the country match well with hydropower resources in the North and South-East of Brazil as the first ones produce more in the second half of the year, and the second ones more in the first half. However, the electrical grid restricts the level of deployment of wind energy [10].

Research on solar energy deployment in Brazil is currently restricted to static analysis of the potentials [9,16,17], with the exemption of Gemignani et al. [18] who model the integration of low shares of solar energy into the grid on a monthly basis for the year 2021. They conclude that the operation of the system is positively affected due to lower marginal costs of production and less probability of loss of load. However, economically those systems are not feasible at current costs. Neither the official government plan for expansion of the power system [1], nor modeling studies [19] see a significantly growing role of solar PV up to 2020, although costs of PV have been decreasing in recent years and although the temporal availability of PV may provide a highly valuable contribution to the Brazilian system [20]: depending on the location in Brazil, daily, monthly, and inter-annual variations may be much lower than those of wind and hydropower. The high variation of the availability of PV during the day, i.e. short-term intermittency of PV, is an often discussed issue [21]. It may, however, be addressed by adding limited storage capacities (i.e. storage capacity for balancing hourly variability during one day) to the system. Longer-term variations in the availability of renewables may much more seriously restrict the expansion of a particular power source as high long-term variations require much larger levels of storage.

We therefore assess an optimal portfolio of hydropower, windpower, and PV power sources for the case of Brazil, using simulated, validated daily time series of power production from two different data sources for a period of 34 years. A simple optimization model is used to generate an optimal mix from a historical set of data. A simulation model is then run on synthetic, bootstrapped time-series to test how a simple dispatch algorithm performs on the operation of the system with respect to thermal dispatch, curtailment of renewables, and loss of load. The results are compared to a case where only hydro and thermal generation is expanded.

The paper first introduces data and methodology. In the results section, we show results of validating the long-term simulated PV power production time-series and the results the optimization and simulation models. The article ends with a discussion and a concluding section.

Data & methods

We use an optimization model to first determine an optimal mix of renewable generation capacities. This model of capacity expansion is using daily time-series of renewable energy production generated from historical meteorological data to determine the mix of generation capacities, assuming perfect foresight. The optimal mix is subsequently used in a simple model that simulates dispatch of power plants, also on a daily level. It uses 100 different bootstrapped scenarios for renewable energy production to assess if the system can be operated in a save way even without perfect foresight about future meteorological conditions. The models and the input data are described subsequently.

Optimization model

We have developed an optimization model that chooses among the modelled timeseries of power production from wind, solar, and hydro resources, manages the hydro reservoirs, and thermal dispatch. The model uses daily timeseries of power production, assuming that sub-daily variations in production are balanced by the availability of storage of up to 24 hours in the system. The appendix elaborates on the quantity of storage that may be needed for that purpose. The model minimizes the production in thermal power plants to achieve a low-carbon electricity supply. The amount of renewables that are additionally deployed is restricted by the amount of electricity demand currently not covered by existing hydro projects. We optimize the system for a period of 34 years with different meteorological conditions in each year to assess daily, monthly, and inter-annual variability of resources.

The objective function is the simple sum of thermal power production x_t^t during the whole time period:

$$\min \sum_t x_t^t \quad (1)$$

The optimization program is restricted by an equation balancing demand d_t with the supply of existing run-of-the-river hydropower plants h_t^h[1], with the immediate use of inflows for production in existing hydropower plants with reservoirs x_t^{hr}, of wind and pv power production at all available locations *l* $\sum_l \left(x_{l,t}^w + x_{l,t}^p\right)$, of thermal power production x_t^t, of run-of-the-river hydropower production at new locations $+x_t^{h\_new}$, of hydropower production using water stored in reservoirs x_t^{st-}, and of curtailing of power production x_t^{cur}, which occurs if renewable power production is too high to be used or stored:

$$d_t = h_t^h + x_t^{hr} + \sum_l \left(x_{l,t}^w + x_{l,t}^p\right) + x_t^{h\_new} + x_t^t + x_t^{st-} - x_t^{cur}, \forall t \quad (2)$$

Hydropower production from plants with reservoir x_t^{hr} and water withhold in reservoirs x_t^{st+} have to be equal to the availability of inflows into the reservoirs h_t^r at that moment:

$$x_t^{hr} + x_t^{st+} = h_t^r, \forall t \quad (3)$$

New hydropower production is assumed to have no storage capacities, hydropower production from new projects therefore equals the availability of hydropower resources at that moment in time $h_t^{h\_new}$ times a variable controlling the deployment of new hydropower resources x^{h_deploy}:

$$x_t^{h\_new} = h_t^{h\_new} x^{h\_deploy}, \forall t \quad (4)$$

The same applies to wind power production $x_{l,t}^w$ and pv power production $x_{l,t}^p$:

$$x_{l,t}^w = w_{l,t} x_l^{w\_deploy}, \forall t, l \quad (5)$$

$$x_{l,t}^p = p_{l,t} x_l^{p\_deploy}, \forall t, l \quad (6)$$

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[1] This input parameter already considers spills of water due to inflows being higher than production capacities at the plants.

Observe that the deployment variables $x_l^{w\_deploy}, x_l^{p\_deploy}$ and x^{h_deploy} do not carry an index *t,* i.e. it is not possible to change the level of deployment during the optimized period. We restrict the produced renewable electricity to the difference between total demand in the whole period minus the production of the existing hydropower plants. This restriction is introduced to limit the deployment of renewable capacities to the amount that is needed to cover additional demand, i.e. to get as close as possible to a fully renewable system. As the time profile of renewables does not perfectly match the time profile of demand, there is still need for thermal backup power, though:

$$\sum_t (d_t - h_t) = \sum_t \left(x_t^{h\_new} + \sum_l \left(x_{l,t}^w + x_{l,t}^p\right)\right), \forall t \quad (7)$$

The level of reservoirs of hydropower plants $x_{t+1}^{st\_lev}$ is determined by the level in the previous period $x_t^{st\_lev}$, by inflows into the storage x_t^{st+} times storage efficiency ρ and by outflows from storage x_t^{st-}:

$$x_{t+1}^{st\_lev} = x_t^{st\_lev} + \rho x_t^{st+} - x_t^{st-}, \forall t \quad (8)$$

The storage level is restricted by the maximum amount of installed storage in the system s^{max}:

$$x_t^{st\_lev} \leq s^{max} \quad (9)$$

Thermal dispatch is limited by the maximum of the installed capacity t^{max} which is predefined:

$$x_t^t \leq t^{max} \quad (10)$$

Simulation model

The optimization model is used to come up with an optimal mix of renewable energies, minimizing thermal power dispatch. However, it is a deterministic program and uses 34 years of historical meteorological data to produce results. Real operation, however, has to deal with future uncertainty about meteorological conditions and our optimization model with perfect foresight is therefore no valid representation of the operation of the Brazilian system. To assess the operational risk imposed by the generation mix which is determined by the optimization model, we also run a simple simulation for dispatch of power plants. The simulation model matches demand and supply. As long as there is more renewable supply than demand, as long as there are water inflows into reservoirs, and as long as reservoris are not full, the inflows are stored. If demand is higher than supply of renewables, reservoirs are used for production until only 50% of the total capacity of the reservoir is left. In that moment, thermal power production is dispatched. This is a simple mechanism to deal with the risk of periods of low rainfalls. Furthermore, if thermal production capacity plus renewables plus run-of-the-river hydroproduction and production from reservoirs is not sufficient to cover demand, a loss of load event is stored for further reference.

Instead of using directly the same 34 years of historical meteorological data that we use for the optimization model, we produce 100 different time-series of 100 years of meteorological data by bootstrapping months from the available data of 34 years. We thus are able to generate different meteorological scenarios, still preserving correlation among meteorological variables and, to a limited extent, auto-correlation of the time-series. By bootstrapping from monthly data, we also preserve seasonality. However, as a January from the year 1985 may be followed by a February of 2007, auto-correlation between monthly aggregates of the time-series is not preserved. Strauss et al. [22] use the same procedure to bootstrap monthly residuals of time-series from historical data for future climate change scenarios, as they argue that climatic conditions generally remain stable for weeks but not for months. Additionally, we also produce extreme versions of the meteorological scenarios, for which once in the whole period randomly 3 consecutive months of hydro inflows are set to 0 to simulate long periods of drought.

Renewable generation data

Solar data

We use the solaR package [23] in the statistical software R, version 3.1.2, to simulate PV production. Cloud coverage is taken into account by using solar irradiation data from global, modelled data sets. There are ground measurements from INPE available, however they cover a very short period of time and contain a high number of data omissions. We therefore validated modelled solar irradiation data from three data sources, i.e. the ECMWF reanalysis project [24], the NCAR/NCEP reanalysis project (NCAR) [25] and from NASA [26] against INPE data (see Table 1) and consequently used those data sets for further assessments. INPE provides data from more than 294 stations, however only a subset of stations was selected that had a sufficient number of data (i.e. more than one year of consecutive feasible measurements) to be used for validation. Subsequently, only this subset of data points was used for further analysis. Validation results are reported in the results section.

Wind data

The simulation of wind power production and the validation of the respective long-term time series, also using ECMWF and NCAR data (see Table 1), is explained in detail in Schmidt et al. [6]. We are using simulated time-series for 34 years (period 1979-2013) derived for the four most important windpower states of Brazil, i.e. Rio Grande do Norte, Ceará, Bahia, and Rio Gande do Sul. The data is validated both with long-term measurements from meteorological stations and with short-term time-series of wind measurements at real production locations. The generation at different locations within a state and at four different points in time per day are aggregated to daily values per state.

Table 1: Data Sources

Type of Data	**Meteorological source**	**Temporal resolution**	**Period**	**Spatial resolution**
Solar irradiation	ECMWF [24]	8 times daily	1979-2014	0.75 x 0.75 Degree Grid, globally
	NCAR/NCEP [25]	4 times daily	1948-2014	2.5 x 2.5 Degree Grid, globally
	NASA [26]	Sum of daily irradiation	1985-2005	1 X 1 Degree Grid, globally
	INPE*	Sum of daily irradiation	1998-2014	294 locations throughout Brazil
Wind speed	ECMWF [24]	4 times daily	1979-2014	0.75 x 0.75 Degree Grid, globally
	NCAR/NCEP [25]	4 times daily	1948-2014	2.5 x 2.5 Degree Grid, globally
Water inflows	Operador Nacional do Sistema Elétrico (ONS) [27]	Daily	1931-2012	Measurements at all Brazilian rivers where hydropower plants are installed

** INPE solar irradiation data was taken from http://sinda.crn2.inpe.br/PCD/historico/radsol_full.jsp. The site is now offline, but today the data may derived from http://sinda.crn2.inpe.br/PCD/SITE/novo/site/index.php after registration.*

Hydro data

The daily hydrological inflows into hydropower plants are taken from a database of the national system operator in Brazil (Operador Nacional do Sistema Elétrico – ONS) [27]. Power production at the power plants is simulated by taking into account the installed turbines and the height of the power plants, taken from the official data set for the decadal energy plan - PDE 2021 [28]. The production values of all power plants without reservoir are subsequently represented by a single power plant in the model. Also, all power plants with reservoir are represented by one power plant with a reservoir of 215 TWh of energy equivalent of water. If water inflows into the run-of-the-river power plant exceeds production capacity, those inflows are assumed to be released without being turbinated and therefore do not contribute to power production. The sum of capacity of run-of-the-river power plants is 44 GW, that one of hydropower plants with reservoirs is 45 GW.

Demand Scenarios, Thermal Power Capacities and Sensitivity analysis

We use daily load data, aggregated from hourly load data for the whole system for the year 2013 [29]. The demand in the scenarios is growing from 2013 levels to three times that level in the different scenarios. An electricity demand growth of 4.2% annually is estimated up to 2022 [1]. Within 27 years, i.e. in the year 2042, this demand level would therefore be achieved, if growth rises also at that rate post 2022.

We run two sets of scenarios: one allowing PV and wind power expansion (NEW_RENEW), the other one with hydropower and thermal power production only (HYDRO). In NEW_RENEW, the maximum capacity of thermal power plants is limited to 15% of maximum load, while this maximum thermal capacity is increased to 40% in the HYDRO scenario. Both values are the minimum necessary to achieve a fully operational system without loss of load in the optimization model.

The validation shows that ECMWF data is better able to reproduce characteristics of measured timeseries for both wind speeds and solar irradiation (see below in the results section for solar and [6] for wind). In the sensitivity analysis we therefore assess how a different meteorological input dataset, i.e. the NCAR dataset for solar irradiation and wind speeds, would affect the outcomes of our optimization model.

Results

Validation of solar data

17 INPE stations in Brazil have met the quality criteria to be used for validation of ECMWF, NCAR and NASA data. The data points are well distributed over the whole of Brazil (see Figure 1) and represent well the variation in climatic conditions and in latitude over the whole of Brazil. There is a major gap in the North-West of Brazil, as most of the region is however currently sparsely populated and partly covered by the Amazon forest it may not be well suited for PV production anyhow.

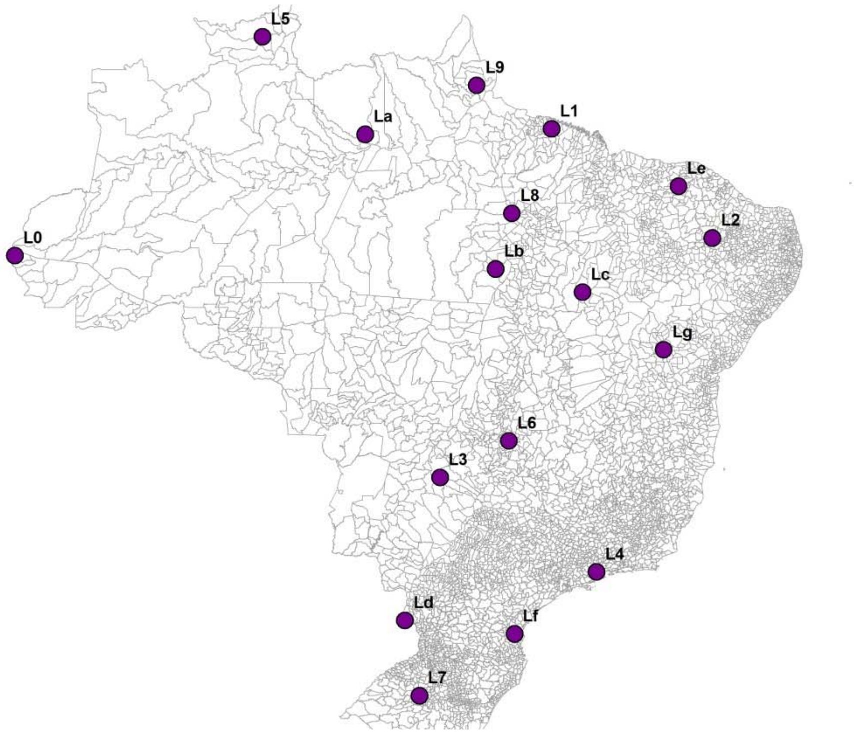

Figure 1: Location of INPE stations used for validation.

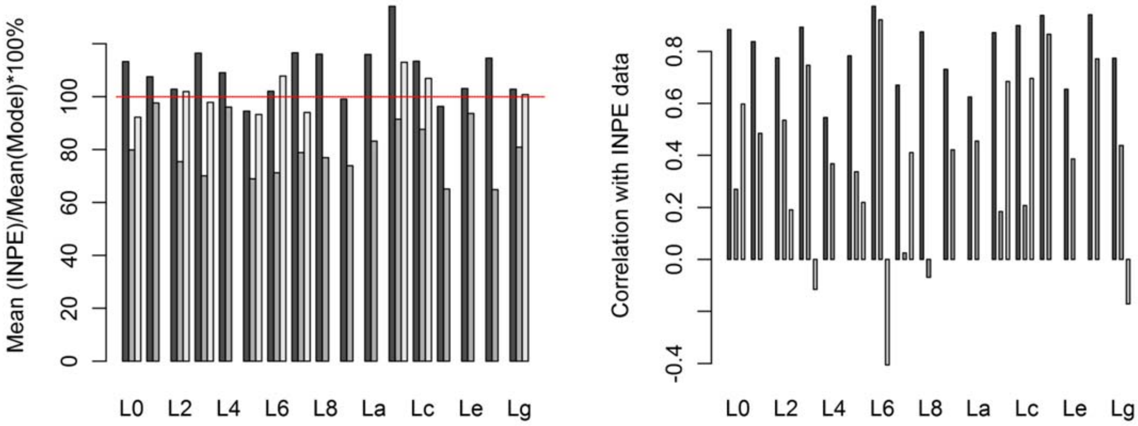

Figure 2: Results of validation of solar irradiation data. Left: Comparison of Mean of Model Data to INPE data. Right: Correlation of Model Data with INPE data. Black is ECMWF data, grey is NCAR data, and light grey is NASA data.

Figure 2 shows a comparison of the mean of the modelled data sources to INPE data and of the correlation between INPE and modelled data. NASA data lacks in some of the comparisons due to a lack of temporal overlap with INPE data: NASA data is only available up to 2005 and INPE data, at some stations, is not available for the whole period 1998-2013. ECMWF data shows, for all stations, the highest correlation with measured INPE data. But even for ECMWF data, correlations are rather low with values below 0.5 for some stations. We have also calculated monthly correlation, which is above 0.5 for all locations, and above 0.8 for all but 5 locations. The production mean is lower at all locations but 2 for ECMWF data, however, deviation is not above 30% for any of the locations. NCAR and NASA data overestimate irradiation, NCAR data being the data set that shows the highest deviation. Variance of ECMWF data is higher than the one of INPE for all but three locations, while NASA data underestimates variance of INPE data for all but 2 locations. NCAR is rather extreme and shows both underestimates and overestimates of variance, depending on the location. ECMWF data seems to be the closest representation of INPE data and is therefore used in the further analysis. However, in a sensitivity analysis we also use NCAR data to see if the data source heavily influences results. NASA data des not seem to be a valid data source for our purposes because (I) validation was only possible for a subset of locations due to the limited temporal coverage of the data set (available only up to 2005) and (II) the dataset shows partly negative correlations with measured data, which is a rather poor performance. To adjust for the rather large differences in mean irradiation, the mean of both datasets is calibrated to the mean of the INPE data.

Optimization model

Figure 3 show the results of the optimization for two different levels of demand, 140% and 200% of current demand and for the NEW_RENEW and the HYDRO scenario. The figures show that with increasing levels of demand, PV production is increased in NEW_RENEW, while no new hydro-power production is installed and wind power production is held almost constant. There is no regular dispatch of thermal power capacities necessary, as seasonal fluctuations are quite complementary and daily variations are well balanced by the existing reservoirs.

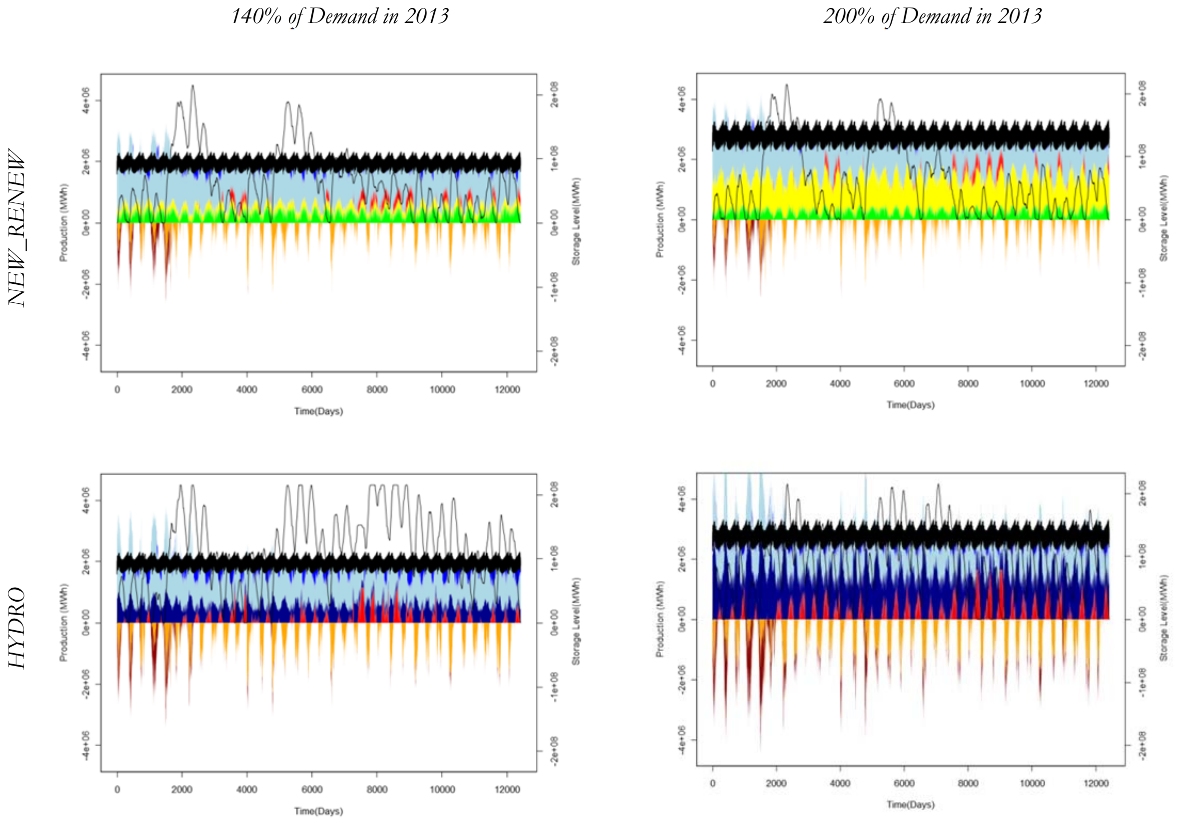

Figure 3: Results of long-term optimization of the power system for 34 years. Left: 140% of current demand, Right: 200% of current demand. Above: NEW_RENEW scenario, below: HYDRO scenario. Note: light blue is hydropower production from inflows, dark blue is production out of hydropower reservoirs, darkest blue is production from new hydropower plants, red is thermal power production, yellow is solar PV power production, green is wind power production, orange are inflows stored in reservoirs and dark red denotes curtailment of power production. The thin black line shows the level of storage in the current scenario, while the fat black line shows system load.

However, in some years substantial thermal power generation is necessary due to low hydrological resources. When the share of PV power production in relation to the other sources increases, it can be observed that thermal power production declines and that dispatch is less often necessary. Spills and curtailing of power generation occurs mainly in the first years due to very large hydrological resources available. If only hydropower and thermal power production is allowed, the figure shows that regular dispatch of thermal power capacities is necessary due to seasonal undersupply of hydrological resources. Also, spills are higher due to the larger correlation of renewable resources. Maximum dispatch of thermal power plants is at very high levels, more than 100% above the level of the NEW_RENEW scenario, indicating that a much higher capacity of thermal power plants has to be available in case of expanding the hydropower system.

Figure 4 shows in detail how the generation of solar PV, wind power, and thermal power develops when demand levels increase in the both scenarios. Observe that existing hydropower production is not shown as it is constant for all periods. The figure shows that in NEW_RENEW at low levels of demand, mainly wind power generation is expanded. Seasonal complementarity with hydrological resources is higher than for PV and explains this pattern. However, when demand increases above 130% of demand in 2013, PV starts to kick in and grows much faster than wind – wind power even decreases at higher demand levels. The reason is that daily, seasonal and interannual variation of PV is much lower than for wind power production, which increases the value of the power source to the system. This is also shown by Figure 5 which presents minimum daily production of the two systems. The daily guaranteed capacity of PV is much higher than that for wind when, for example, comparing a demand level of 150%, where annual generation of PV and wind is almost equal. PV has a guaranteed capacity of at least 4% of installed capacity, while wind has a guaranteed capacity of only 0.001% of installed capacity. At higher deployment levels of PV, the guaranteed capacity rises to even 44% due to spatial diversification (see Figure 5 below)..

In HYDRO, only new hydropower production is expanded. While spills and thermal power production remain constant or even decrease slightly with increasing demand levels in NEW_RENEW, in the HYDRO scenario spills and thermal power production grow steadily as a consequence of the high correlation between new and old renewable resources.

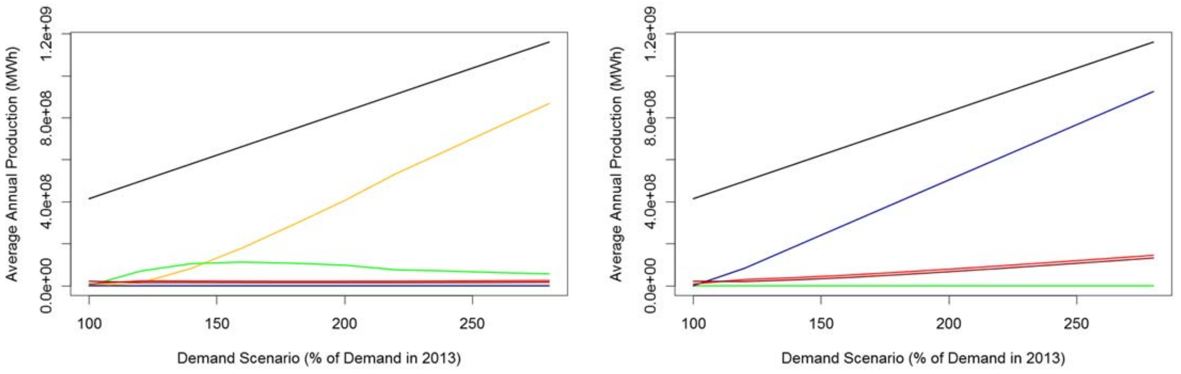

Figure 4: Production from different sources of renewable electricity and maximum thermal capacity. Left: NEW_RENEW scenario, right: HYDRO scenario. Note: Black is total demand, yellow is PV power production, green is wind power production, blue is new hydropower production, darkred is spills, and red is thermal power production.

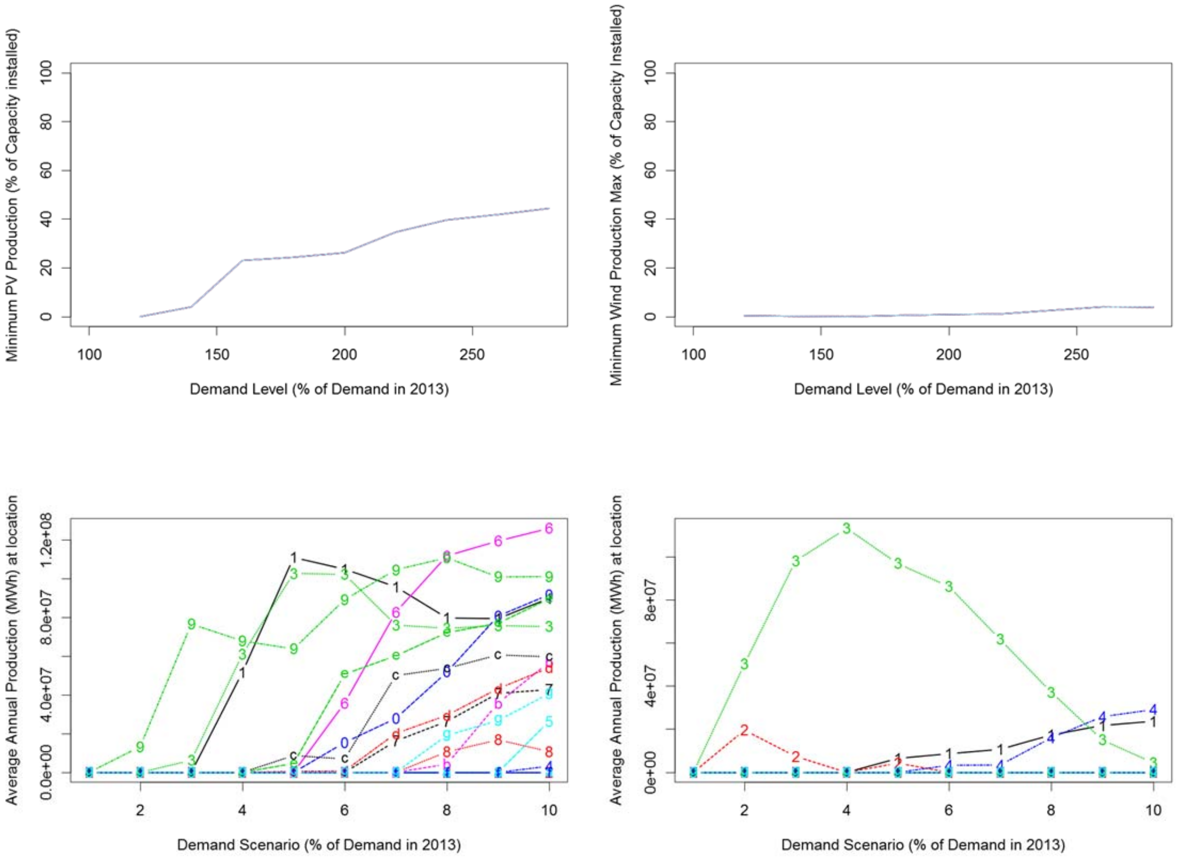

Figure 5: Above: minimum guaranteed capacity for PV (left) and wind (right). Below: Locations chosen in the optimization model for PV (left) and wind (right) generation. Note: The numbers for solar refer to the numbers in Figure 1. For wind power, (1) denotes Bahia, (2) Ceará, (3) Rio Grande do Norte, and (4) Rio Grande do Sul.

Simulation model

The simulation model shows results similar to the optimization model for both scenarios (see Figure 6), although thermal power production is higher – this is a result of the simulation procedure which is not able to optimally allocate resources. However, even in the extreme drought scenarios the loss of load does not exceed 0.14% in any of the NEW_RENEW scenarios. This is a result of the very stable output of combined solar, hydro and wind power renewable power production. However, in HYDRO up to 1% of total demand cannot be covered by the available production capacities when dispatching with the simple algorithm. Also, with increasing demand levels, the share of thermal power production, of spills and uncovered demand do increase while the opposite is the case for the NEW_RENEW scenario, i.e. adding more hydropower to the system will increase operational complexity due to higher variability in output while the opposite is the case for adding a mix of wind, solar, and hydropower. The simulation model shows that even with a very simple dispatch heuristic, the risk of loss of load can be held very low in a scenario that mixes the three renewable sources.

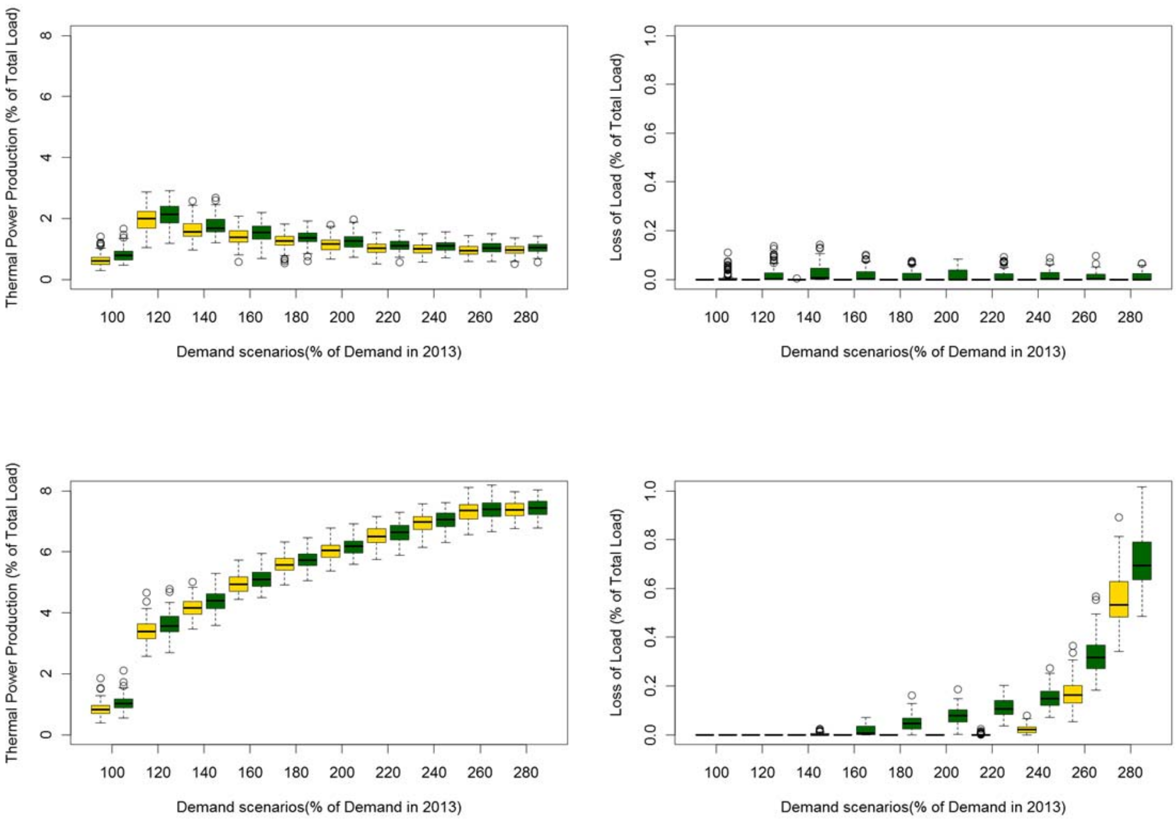

Figure 6: Left: thermal power production (% of total production). Right: loss of load (in % of total load). Above: NEW_RENEW scenario. Below: HYDRO scenario. Yellow: Bootstrapped scenarios from historical data. Green: bootstrapped scenarios from historical data including a random 3 month period without any hydro power inflows.

Sensitivity Analysis

In our sensitivity analysis, we have assessed the impact of different meteorological data sources, on the outcome of the optimization model in the NEW_RENEW scenarios. The overall picture remains the same, i.e. high shares of solar PV and much lower shares of wind power deployment. However, ECMWF shows higher levels of wind power for lower levels of demand and lower levels at higher levels of demand (see Figure 7) and the contrary for solar PV. This is a result of a slightly different seasonality of wind power data in the data sets as shown by Schmidt et al. ***[6]***. Also, different generation locations are chosen when using the two datasets.

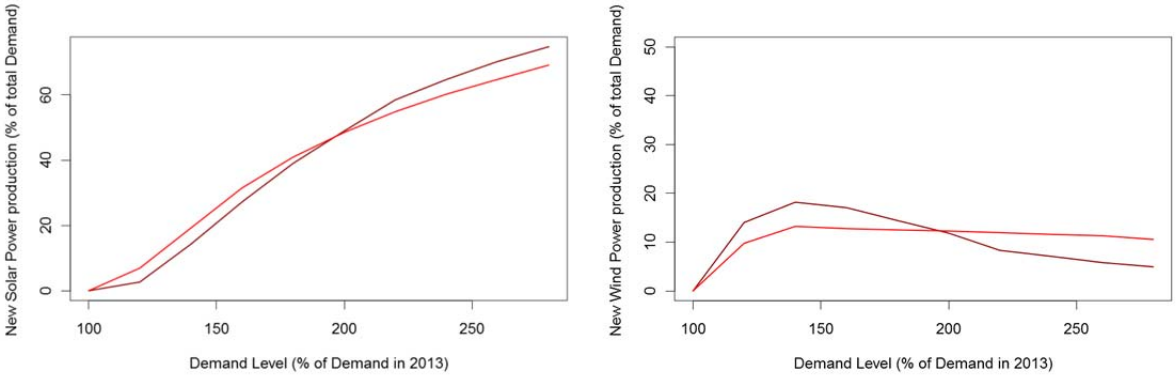

Figure 7: Comparison of NCAR (light red) and ECMWF (dark red) results for the deployment of PV (left) and wind power (right).

Discussion

The dispatch problem in a system as the integrated Brazilian system is much more complex than our simple optimization model is able to depict. Therefore, several important assumptions have to be made to assume that the shown dispatch is feasible. First, the expansion of the electrical system as proposed in this article depends on the availability of an electricity storage that is able to store at least one day of electricity production at high efficiencies and at high capacities for charging and uncharging the system. This is necessary as we use time-series of wind and PV production of daily resolution. PV production has a very high variability during the day (i.e. no production in the night), this variability therefore would have to be balanced by storage (see the Appendix for an estimation of necessary storage capacities).

We did not assess if currently installed transmission and distribution lines would be able to handle the load. Of course, an expansion of the transmission system is necessary in any expansion scenario, independent of the generation technology, if electricity demand increases substantially in the long-term. As most of the expansion in our model results come from PV, this may even allow for more efficient use of transmission capacities: solar irradiation is by far not as concentrated as other sources of power such as hydropower or wind power generation – or even gas power that has to be located close to gas producing sites or close to gas pipelines which are still rare in Brazil. Due to the low spatial variation of solar radiation, the location of a particular site for installing PV can be chosen to be close to an existing transmission line. Also, instead of building large scale PV plants, smaller scale plants closer to demand centres and even distributed generation could reduce the need for additional transmission lines – and could reduce the pressure on delicate ecosystems and on socially conflictive land. The geographical resolution of our data set is too limited to assess those options – however, our results can be considered conservative as further spatial diversification would further reduce the total variance of renewable output and therefore further reduce the need for thermal backup generation.

There remains uncertainty on the meteorological input data. Validation of modelled solar radiation and wind speed data with ground measurements showed a relative large error margin. Increasing quality of both, modelled data and of future ground measurements, may therefore reduce the uncertainty on the behaviour of the meteorological system. Also, a better modelling of local conditions by combining ground measurements with modelled data as performed by Szczupak et al. [30] may increase confidence in results. It also has to be regarded that local and global climate regimes may be subject to rapid changes, which is not considered in the current analysis and which may alter our results. However, the sensitivity analysis confirms that independent of the source of data, the main results of our analysis – i.e. high shares of PV and no new hydropower production – are confirmed. Additionally, a stochastic model of the meteorological data, considering seasonality, auto-correlation, and correlation between different sources of renewable power and different production locations may allow to generate better synthetic time-series for assessment of uncertainty than the simple bootstrapping procedure used here. In particular the monthly auto-correlation in the variables is not considered by our sampling procedure and is an interesting line of future research.

We did not take into account costs of the different technologies but used the assumption that Brazil aims at a low carbon energy matrix, continuing past efforts. Obviously, PV generation is currently the most costly from the three regarded power sources and pure economic optimization would not allow PV generation at the moment. However, costs have been drastically decreasing in the last years and currently, levelized costs of electricity for PV are competing with costs of gas and wind power in the United States [31] – and are only around 40%-50% above wind costs in Brazil, already being able to compete with gas power plants when considering levelized costs of electricity [8]. Further steps down the learning curve may therefore allow an economically profitable operation of PV in Brazil at least at locations where solar irradiation is high. We did not assess the economics of our solution as future projections for PV are highly uncertain. Decreasing costs by expansion of the sector in Brazil is therefore of high importance to be able to profit from further cost decreases along the supply chain. The same is true for storage which is essential to accommodate a large share of PV. Pumped-storage plants may be a feasible option in Brazil [32], however, their costs may be prohibitive due to the high need for generation capacity (see appendix). Batteries are currently still too expensive in terms of storage capacity. However, as occurred to PV, costs of storage may rapidly decrease, driven by the rapid uptake of electric cars in Europe and the United States, where emission standards for cars are increasingly tightened. Storage is only necessary when installed PV capacity exceeds a certain threshold of total capacity. Up to that moment, developments in the storage market should be carefully monitored to assess future conditions for the further uptake of PV. It may also be considered that concentrated solar power plants have a daily and seasonal time profile of production similar to PV, but allow for a better temporal distribution of production throughout one day. It may therefore been an interesting line of future research to assess the integration of CSP instead of PV into the system.

We did not assess land use implications of a large expansion of wind and PV power plants. Again, PV has great advantage over other forms of renewable energy production as it depends less on particular sites for deployment due to the availability of significant solar irradiation in Brazil at many locations. Therefore, conflicts with other land uses may be minimized. Also, at least part of the capacity may be installed as decentralized generation on roofs of buildings, thus not contributing to land use conflicts. Still, a thorough analysis of the availability of land and the design of an open, transparent, and participative process in acquiring land for renewable energy production are subject to further research.

Other studies that take a more technical look into the system, modelling in detail the current electricity system and the integration of intermittent renewables come to much less optimistic conclusions with respect to the deployment of intermittent renewable sources. However, our approach is a long-term one and shows that variability of the renewable power sources, in case daily storage is available, can be very well balanced by combining different renewable sources, by relying on the current system of hydropower reservoirs, and by providing a limited thermal backup capacity.

Conclusions

We have shown that PV and wind can contribute to stabilizing the daily, monthly, and annual combined hydro-wind-PV output compared to a hydro-thermal system only and could substantially decrease the need for thermal power generation. Thermal power backup capacity would not have to be expanded from current levels to guarantee high levels of security of supply. Subdaily, i.e. hourly variation of PV supply would have to be balanced by storage, however.

The expansion of hydro power from current sources, however, is not found to contribute in decreasing the need for thermal backup capacities and thermal power generation. The high seasonal and inter-annual variability of the resource and the fact that, in the future, very few reservoirs are going to be built, reduces the value of this renewable resource in providing a stable power output.

The expansion of wind power is less valuable in terms of stabilizing total output, however up to 9% of demand may be supplied by wind power when demand is doubled from the levels of 2013. There is still high uncertainty on the long-term variance of that renewable power source, research in this area is therefore of outmost importance.

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Appendix: Storage needs

We consider only daily dispatch in our model. However, solar PV and wind power show large hourly variation. In particular the production of PV is concentrated in few hours of the day. The shown dispatch of power capacities is therefore only possible, if storage is added to the system to allow balancing supply and demand over the day. The amount of storage necessary can only be roughly estimated as there are no hourly estimates for neither hydro-power production nor wind-power production available to us. Still, we do so for the scenario of doubled demand from 2013 levels, using hourly PV production as simulated by the solaR package [23] in R. The hourly dispatch of other sources, i.e. run-of-the-river hydropower, hydropower from plants with reservoirs, wind power, and thermal power was distributed evenly over the day by dividing daily production by 24. This is obviously a very rough estimate: in particular wind power may have very large variations during the day, whereas power from thermal sources and from hydropower storage plants can be dispatched at will by the system operator. Run-of-the-river hydropower plants mostly have little storage capacity to balance intraday variance in demand, they therefore may also be used to further balance the system. We therefore assume that the combined wind, thermal, storage, and run-of-the-river power production is stable during the day by dispatching hydro plants and thermal power plants at the right times during the day (i.e. when wind production is low). PV is added to base-load production and the difference to hourly load in the network is determined. Daily load values always match daily production values as a result of the optimization process, we therefore only have to consider the variations during one day. We calculate the maximum daily over- or underproduction in the system to determine the storage capacity in GWh and the maximum over- or undercapacity in the system to determine the production capacity of the storage in GW. Figure 1 shows an example of load, production, and residual load for four sample days. The results show that, when load is doubled from the level of 2013, a maximum of 167 GW of charging capacity have to be in place, while a maximum of 913 GWh of storage capacity have to be guaranteed for a feasible hourly dispatch along the simulated period of 34 years. While the storage capacity can be considered low for pumped-storage power plants – Brazil fosters a total of 215TWh of storage capacity in hydro-reservoirs - the charging capacity is very high, i.e. a huge amount of additional turbines would have to be added to the system. The opposite is true for batteries: charging and discharging rates of around 5 to 6 are available in commercial batteries. However, a storage capacity of 913 GWh is currently economically not feasible. If long-term costs, however, decrease by a factor of 5 to 10, an economical operation of a combined PV/battery system may be possible in comparison to current fossil fuelled power generation. Another option may be the use of concentrated solar power with storage for hot water instead of relying on PV with battery storage.

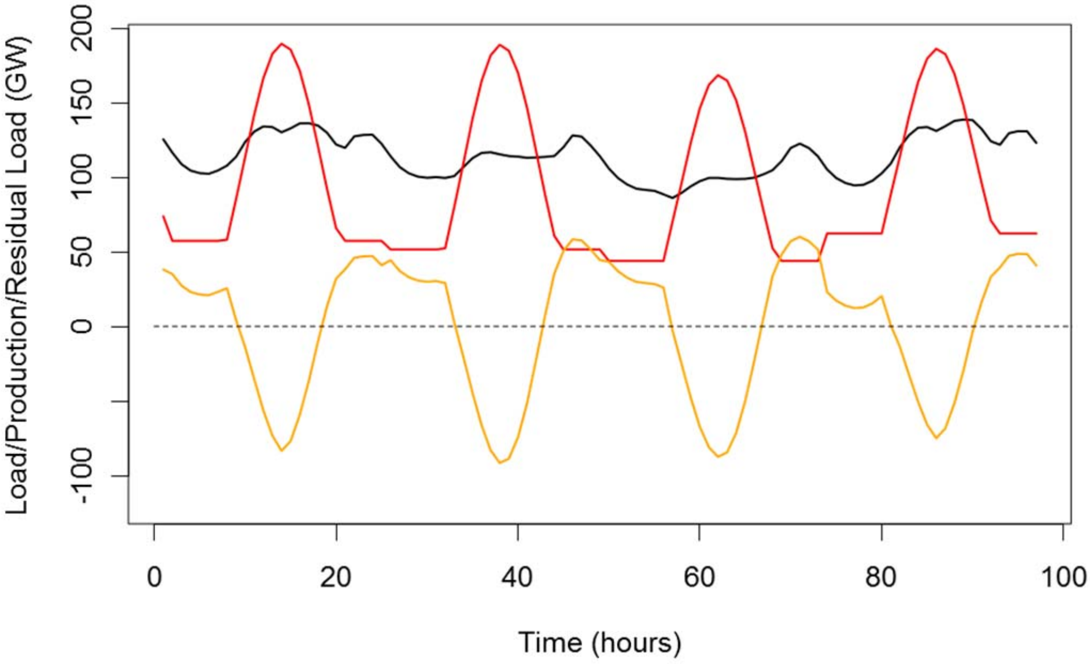

Figure A1: Load (black), production (red), and residual load (orange) for four sample days.