

Turbines of the Caribbean: Decarbonising Suriname's electricity mix through hydro-supported integration of wind power

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ABSTRACT

The Caribbean nation of Suriname has historically depended on a mix of hydropower and oil-based fossil fuels for meeting electricity needs. Continued reliance on fossil fuels poses challenges both for climate change mitigation and for energy security. This paper explores the potential for increasing the share of renewables in Suriname's electricity mix, with a special focus on the complementary role of existing hydropower and future wind power infrastructure. We show that these resources have great synergetic potential for displacing fossil fuel-based power generation. Flexible operation of the Afobaka hydropower plant, newly in full possession of Suriname, allows significant wind power integration without violating grid stability and associated power quality requirements. Considering the trade-off between displacing expensive fossil fuels and limiting wind power curtailment on Suriname's island-like grid, our results suggest that integrating wind power in the Surinamese electricity mix is economically advantageous up to a share of 20–30%, independently of near-term demand growth. These results have wider relevance for climate policy in various Caribbean countries and other island states with existing hydropower infrastructure and substantial wind/solar power potential, for which this study fills an important literature gap.

1. Introduction

Worldwide, many countries are planning to increase the share of renewables in their electricity mix, steering away from fossil fuels both to support global emission reductions [1] and to ensure energy security [2]. Recently, wind and solar power technologies have been becoming more cost-competitive every year compared to fossil fuels [3], leading to substantial interest in their grid integration. The variable nature of wind and solar power is a major constraint in this regard, especially in the context of relatively weak, low-inertia grids, the limiting factor being violations of grid stability requirements and associated power quality issues at high penetration of variable renewable energy (VRE) [2].

Particular challenges may exist for states with isolated grids such as

the Caribbean islands [4–9], for which neither spatial resource spreading [10] nor cross-border interconnections [11] are realistic ways of improving grid stability prospects. An obvious solution would be having sufficient dispatchable backup and/or storage capacity, but dispatchable generation is often fossil-fuel based [12], and battery storage costs - although declining - are still high [2,13]. Yet, there is general consensus in the Caribbean region and among other Small Island and Developing States that shifting towards VRE is desirable for sustainable development [2,14].

The Caribbean country of Suriname, although not an island state, is island-like in the sense that its largest grid system EPAR (Electricity PARAMaribo, covering 90% of Suriname's electrical load) serves a relatively small area and has no interconnections to other grids (Fig. 1).

Abbreviations: CapEx, Capital Expenses; ELCC, Effective Load Carrying Capability; EPAR, Electricity PARAMaribo; HPP, Hydropower plant; IRRP, Integrated Resource and Resilience Planning; ITCZ, Inter-Tropical Convergence Zone; LCOE, Levelised Cost of Electricity; NDC, Nationally Determined Contribution; OpEx, Operational and Maintenance Expenses; PV, Photovoltaics; REVUB, Renewable Electricity Variability Upscaling and Balancing; RLDC, Residual Load Duration Curve; VRE, Variable Renewable Energy.

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Despite this, its inertia is relatively high owing to the substantial contribution to the electricity mix by the 189-MW Afobaka hydropower plant (72% of total installed capacity on the EPAR grid [15]), turbinizing water from the Brokopondo reservoir. Built in the 1960s, Afobaka was originally conceived to benefit a foreign commercial firm active in the aluminium industry; at the turn of the century, as industrial activity declined, the firm instead started selling hydroelectricity to Suriname through a Power Purchase Agreement [16]. Since then, hydropower has provided nearly 60% of Suriname's electricity needs on average, with thermal (diesel and heavy fuel oil) power providing the rest [17]. With the firm's recent full withdrawal from the country, the Afobaka plant was handed over to Suriname on 31 December 2019 [18].

Given the dispatchability of reservoir hydropower plants such as Afobaka [10,20–23], hydro-supported integration of VRE could be a promising avenue for Suriname to displace fossil fuel-based power generation. This could carry substantial benefits both in terms of emissions mitigation [1] and of avoiding fuel costs of oil-based commodities on volatile world markets [2]. In recent years, a solid literature base on hydro-VRE complementarity has emerged, consisting of roughly four categories. However, as we argue in the following, all of these leave an important literature gap for applications of hydropower flexibility on islands and in island-like countries, such as Suriname.

Studies in the first category assess spatial and temporal hydro-solar-wind complementarities by applying mathematical indicators, typically correlation-based, to hydrometeorological variables [24]. Examples include an investigation of two-way complementarity between wind speeds and precipitation [25] and wind speeds and streamflow [26] in Brazil; and of three-way complementarity between wind speeds, solar radiation and streamflow in Brazil [27] and Europe [28]. While valuable as initial assessments, such studies neglect the role of operational schemes of hydropower plants, and are thus mostly applicable to non-dispatchable run-of-river projects, not reservoir-based hydropower.

Studies in the second category address the operational aspect of

reservoir hydropower alongside VRE by investigating synergies at individual power plant level, such as e.g. joint operation of hypothetical hydro and wind power plants in Mexico [29], strategies for cascaded hydropower, small hydropower and pumped hydropower with solar and wind in southwestern China [30–32], day-ahead scheduling of hydro-solar-wind-thermal power generation in northwestern China [33], or the operation of China's Longyangxia hydro-PV plant, the world's largest hydro-VRE complex [34–39]. These have been highly valuable in uncovering the potential for hydropower to support VRE integration. However, a common element across these studies is that each tends to concentrate on certain temporal scales, lacking an integrated framework to simultaneously account for hourly-to-multiannual trends, as is recommended [20,40].

Studies in the third category do integrate these timescales, but typically focus on larger areas with less detail on individual hydropower plants; examples include e.g. regional integration of hydropower in the Zambezi basin with wind power in South Africa [41], impacts of hydro-wind integration on reservoir operation in the Southeastern US [42], hydropower mitigating spot-market value drops of wind power in Sweden at high penetration [43], or the role of hydropower in high-VRE scenarios for the Nordic countries [44].

The fourth category of studies takes this even further, focusing on large-scale interconnected grids for entire continents, but lacking results on individual hydro and VRE power plant level [11,45–47]. An exception to this is a recent study on integrated hydro-solar-wind planning and its synergies with regional power pooling in West Africa [20], which integrated hourly-to-multiannual and plant-to-regional trends. However, like other studies focused on spanning large geographical areas, it concentrated heavily on the potential for regional power trade to increase VRE penetration. There exists thus a clear gap in literature for strategies adapted to island states and isolated regions, for whom electricity exchange with neighbouring territories is no option to leverage solar and/or wind power.

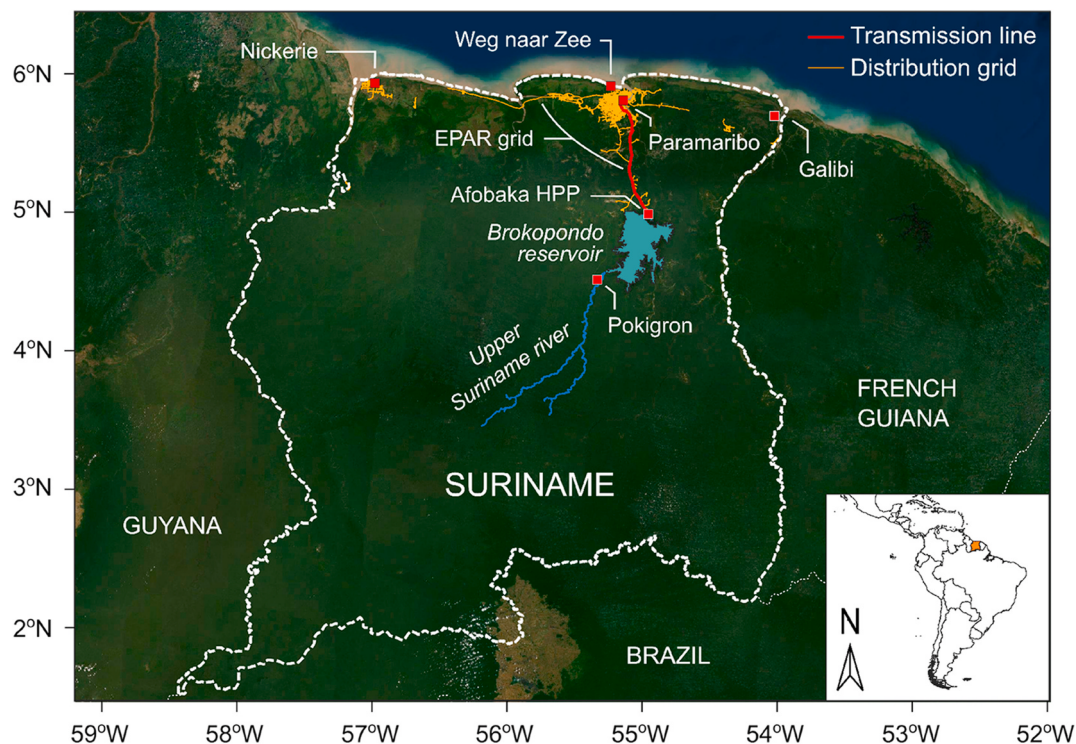


Fig. 1. Overview of the study area. Map of Suriname, indicating the Afobaka hydropower plant (HPP) and Brokopondo reservoir, the measurement station at Pokigron, the high-voltage (161 kV) transmission line from Afobaka to the capital Paramaribo, the EPAR grid serving Paramaribo and its surroundings, and the windy coastal locations Galibi, Nickerie and Weg naar Zee. Background: Esri's World Imagery [19] (see Acknowledgements). Inset: Suriname's location along the South American Caribbean coast.

To summarise, most studies on hydro-supported VRE integration do not cover all the relevant temporal scales, and those that do so either lack the spatial detail necessary for assessing island (-like) grids, or focus explicitly on strategies that are no option for islands and territories with isolated grids. The present study has been elaborated to address this literature gap.

This paper discusses the potential of hydro-supported wind power integration in Suriname, exploring hourly-to-multiannual resource complementarities and pathways towards high wind power penetration to displace thermal (diesel and heavy fuel oil) sources from the electricity mix of Suriname's isolated EPAR grid. The paper also discusses the potential for solar power, the role of transmission, implications for energy/climate policy in other Caribbean countries and island states, and the Paris Agreement context. In the following sections, the model framework (section 2), data and assumptions (section 3), and the principal results (section 4) are described, before discussion points (section 5) and conclusions (section 6) are summarised.

2. Hydro-wind complementarity

This section discusses the climatic context behind Suriname's hydro-wind complementarity (2.1), the model framework used to conduct this study (2.2), and the principal trade-off to be investigated for high renewable infeed on island (-like) grids (2.3).

2.1. Climatic context

From a climatic perspective, Suriname's wind power and hydro-power potential are roughly anti-correlated because wind speed and rainfall show opposing seasonal cycles. The climate of Suriname is characterised by a short (December–January) and a long (April–August) rainy season. The highest wind speeds occur around the short rainy season, when the Inter-Tropical Convergence Zone (ITCZ) is at its southernmost location and strong northeasterly Atlantic trade winds reach the coastline; the lowest wind speeds occur during the long rainy season, when the ITCZ has moved north and prevents trade winds from reaching the coast (Fig. 2a) [48]. Correspondingly, the yearly refilling of the Brokopondo reservoir by the Suriname river mainly takes place during the low wind season (Fig. 2b).

From an electricity mix perspective, therefore, hydropower and wind power could be highly complementary in Suriname, with (i) hydropower dominating during one part of the year and wind power during another, (ii) the high flexibility of dispatch of the Afbaka hydropower plant helping to compensate the year-round hour-to-hour variability of wind power generation, and (iii) the multi-year storage capacity of the Brokopondo reservoir helping to compensate for potential interannual variability in both hydropower and wind power potential. As such, a hydro-wind mix [10,29,41,43,49] could be effective in displacing substantial amounts of thermal power generation - responsible for the bulk

of Suriname's energy-related greenhouse gas emissions - from the power mix, without wind power variability becoming a problematic issue for grid stability.

2.2. Model framework

To estimate the wind power generation (and corresponding installed capacity) whose power mix integration could be supported by the Afbaka hydropower plant, a methodology is needed to explicitly couple hydropower, wind power and electricity demand at hourly resolution over long time periods. Such a model should consider various limiting factors on hydropower flexibility: (i) standard constraints such as maximum power output and maximum ramp rates; (ii) minimum stable reservoir outflow needed for grid inertia and environmental purposes; and (iii) the sustainability of Brokopondo lake levels which should be guaranteed on multi-annual time scales (based on the reservoir rule curve), even with flexible hydropower operation in function of wind speeds.

Scientific literature has made important progress in modelling hydro-wind-solar integration in recent years [29–39, 41–43, but often (i) relied on closed-source software, and/or (ii) focused on subsets of the relevant temporal scales, e.g. only on daily timescales, a certain season, or a single year, although interannual variability is of prime importance for renewables' integration studies [20,40]. The recently developed Renewable Electricity Variability, Upscaling and Balancing (REVUB) model (<https://github.com/VUB-HYDR/REVUB>), an open-source software originally used to assess the potential of hydro-wind-solar power mixes in West Africa from hourly to decadal scale [20], is well-suited to address the above challenges. Full details on the technical characteristics of the model are given in Ref. [20]. We provide a brief summary of the model below.

The REVUB model derives hydropower reservoir operation rules as based on certain needs for flexibility determined by the hourly variations in VRE generation and electricity demand. This is done while ensuring compliance with minimum outflow or minimum stable output constraints of hydropower plants, and ensuring that reservoir rule curves are followed as closely as possible. Starting from an initial state of reservoir filling, the model marches forward in time by dispatching hydropower as necessary to follow a certain target load together with VRE. It recalculates the reservoir state at each next time step depending on the water released (turbined and/or spilled) in the previous time step, the water received from upstream, and net gains/losses on the lake surface. After a simulation, which should preferably span multiple years to take the full effects of seasonality and interannual variability of reservoir operation into account, the model verifies whether lake level stability (according to the rule curve) can be guaranteed under the simulated operation. If this is the case, the model resimulates for a higher target load, iterating until the highest target load is identified with which lake level criteria can be adhered to. In the following, this

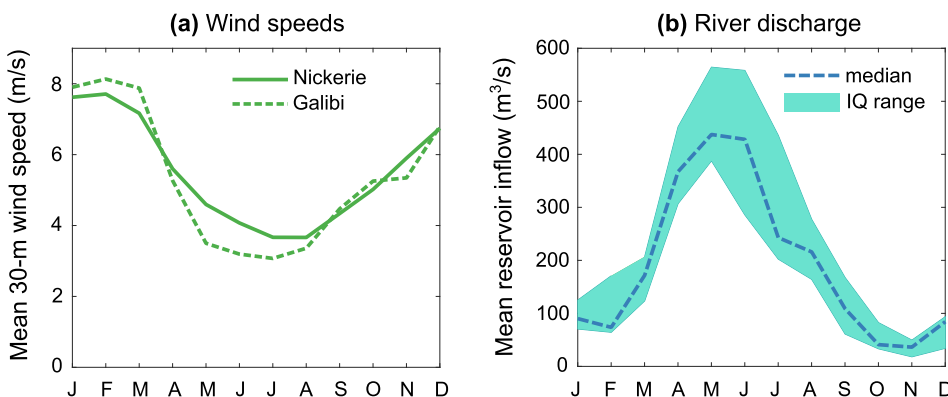


Fig. 2. Seasonal wind-hydro complementarity in Suriname. (a) Mean monthly wind speed in the coastal locations Nickerie and Galibi (Fig. 1), from measurements at 10-min resolution in the period 08/11/2009–08/11/2010 (see Section 3.2); (b) median and interquartile range of average monthly inflow from the Suriname river into the Brokopondo lake, from measurements at daily resolution at Pokigron during the period 01/01/1975–29/12/1983 (see Section 3.1). See Acknowledgements for data sources.

highest possible target load is denoted the “Effective Load Carrying Capability” (ELCC) of hydro-plus-VRE.

The REVUB model has already been used and validated for numerous large reservoirs in West African countries situated in similar climate zones as Suriname, and with similar power generation profiles dominated by thermal power and hydropower, such as Ghana and Côte d’Ivoire [20]. This validation was done by comparing modelled lake levels to remotely sensed lake level elevations, as well as by comparing modelled hydropower generation to historically recorded values, yielding promising results. Given the similarities in latitude, seasonality of rainfall, and power mix characteristics between various West African countries and Suriname, the model is deemed appropriate for application to the Surinamese context of this study.

Based on multiannual time series of lake inflow, evaporation, wind power potential, reservoir dynamics, and electricity demand at hourly resolution, the REVUB model is used here to calculate the share of electricity demand that could be followed - hour by hour, season by season and year by year - by a combination of flexible hydropower from Afbaka and variable wind power generated along Suriname’s coastline, taking into account all above-mentioned constraints. The ELCC here thus corresponds to the fraction of total load that is guaranteed to be reliably met by hydropower and wind power for every hour on a multiannual time scale. This translates to the level of wind power generation that could be integrated in Suriname’s power mix through hydro-driven flexibility, and the amount of thermal power that could be consistently displaced from the mix.

Since Suriname’s island-like grid cannot export excess power, these results are sensitive to the extent to which wind power curtailment would be deemed acceptable during periods of very high wind speeds and/or low demand [50,51]. This is described in more detail in the next subsection.

2.3. Overproduction and curtailment

The term “overproduction” is used here to denote wind power exceeding the ELCC in moments when hydropower has already ramped down to its minimum (stable) level. During such moments, thermal power must additionally ramp down to allow further wind power penetration, and if this is no option, wind power must be curtailed to safeguard grid stability. In other words, overproduction denotes wind power generation beyond a level which can be supported by

complementary hydro-wind operation. In this context, three possible situations can be distinguished, depicted schematically in Fig. 3 for an example 24-h period of hydro-wind-thermal power generation in Suriname: (a) no overproduction, (b) overproduction without curtailment, and (c) overproduction with curtailment.

If overproduction would not be allowed (Fig. 3a), wind power variability would always have to be fully compensated by increasing or reducing hydropower output. Thermal plants would then have to cycle up and down following the residual load (total load minus renewable generation), equalling a constant fraction of the instantaneous total load (Fig. 3d). Clearly, not allowing any overproduction would place a stringent upper limit on the achievable wind power penetration.

Relaxing this constraint would allow increased wind power penetration (Fig. 3b). Thermal power plants would then have to ramp up and down more frequently to ensure grid stability, as the hydro-plus-wind profile would no longer always represent the same fraction of the total load, and the residual load would therefore exhibit an extended range (Fig. 3d). (For the purposes of this analysis, the thermal plants in Suriname are assumed to be technically capable of following such residual loads [52,53].)

At high allowed rates of overproduction, it is possible that total hydropower and wind power generation would sometimes exceed the total electricity demand (Fig. 3c). During such periods, wind power generation would need to be partially curtailed and thermal plants would have to remain idle (negative values in Fig. 3d) to ensure grid stability.

The important question, especially for island (-like) grids, is to what extent accepting curtailment can be a cost-effective option of displacing high amounts of thermal power from the mix [50,51]. Elucidating this trade-off is one of the principal goals of our analysis.

3. Data and assumptions

REVUB simulations were set up using high-resolution (i) river inflow and evaporation data for the Brokopondo reservoir and detailed technical/design characteristics of the Afbaka plant (3.1), (ii) wind speed data representing conditions along Suriname’s coastline (3.2), and (iii) electricity demand data for the EPAR grid (3.3).

3.1. Hydropower

The water budget of the Brokopondo reservoir was modelled using

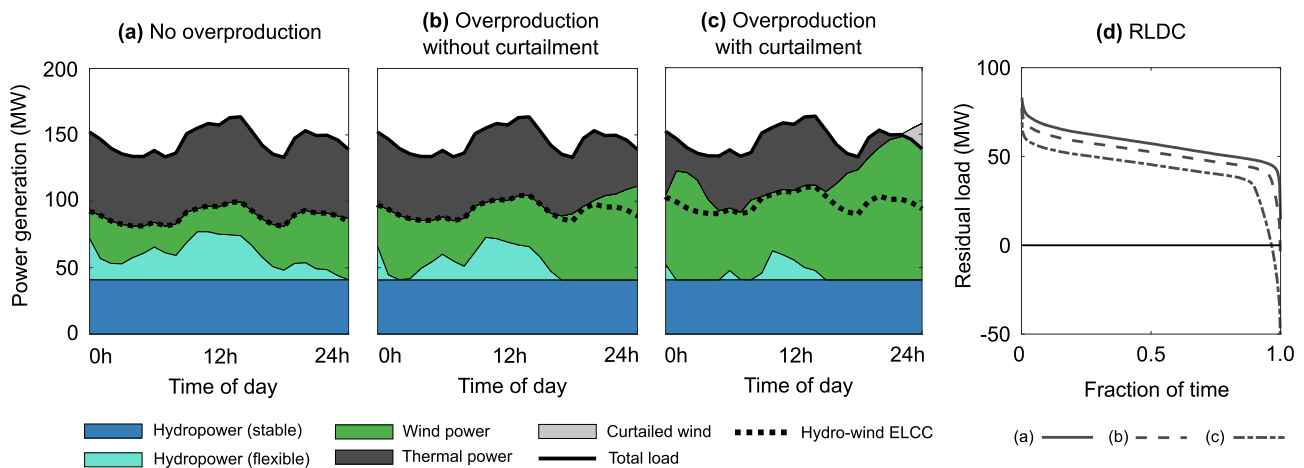


Fig. 3. Hydro-wind-thermal operation under different wind power penetration rates. Schematic of the three stages of overproduction, showing the same single day (February 9 in year 5) from a simulation of Suriname’s electricity mix with hydro, wind and thermal power, covering nine years at hourly resolution and run with three different overproduction constraints (and otherwise the same simulation settings as in Fig. 5; see section 3 for data sources). In the first stage (a), the hydro-wind ELCC (Effective Load Carrying Capability) must be exactly equal to the sum of hydropower and wind power, i.e. zero overproduction. In the second stage (b), this constraint is relaxed, allowing higher wind power penetration. In the third stage (c), the constraint is relaxed further, leading to a situation in which wind power must sometimes be curtailed. The residual load duration curve (RLDC), reflecting the load that thermal power plants must follow, is shown in (d) for all three cases (based on hourly data from the entire nine-year simulated time series) against the fraction of total time spanned by the simulation time series.

time series of river discharge and reference evapotranspiration recorded at Pokigron (Fig. 1) at daily resolution during the period 1975–1983. Inflow into the reservoir was based directly on the measured river discharge; evaporation from the lake surface was estimated by correcting the measured evapotranspiration with a pan evaporation factor of 0.6 [54], assumed to include the compensating effect of rainfall on the lake surface. It is to be noted that, while a rainfall time series was also available from the same station, such local rainfall measurements tend not to reflect the total rainfall over lakes as large as Brokopondo very well, as they usually modify the local climate [55].

It was assumed that 60% of the water budget available for turbina-tion in the Afobaka plant should be released at a constant rate, even under flexible operational rules designed to compensate for the variability of wind power. The purpose of stable outflow is to generate baseload power and ensure sufficient grid inertia, since any hydro-supported wind power take-up will displace thermal power from the mix and thus reduce the amount of synchronous spinning generation on the grid. Such a stable outflow additionally benefits environmental purposes [20,56]. The stable outflow was thus fixed at 60% of the long-term average outflow; the latter was taken to be $135 \text{ m}^3/\text{s}$, i.e. the median value of multiannual reservoir inflow, based on previous studies on the Afobaka plant [57] (cf. Fig. 2b).

Various technical and design characteristics of the hydropower plant as implemented in the simulations are shown in Table 1. The bathymetric (head-volume) relationship of the Brokopondo reservoir is shown in Fig. 4a, and its lake level rule curve in Fig. 4b. The latter represents a near-sinusoid oscillating between 51.13 m hydraulic head in April and 53.27 m in September. In this range, the bathymetric relationship is linear by approximation (cf. Fig. 4).

To validate the assumption that the inflow and evaporation from 1975 to 1983 are valid for present-day simulations of hydropower generation, the average hydropower output resulting from our REVUB simulations was compared to the amount which Suriname used to buy on a yearly basis from the commercial company exploiting the dam before it entered Suriname's possession at the end of 2019. The Power Purchase Agreement between the two parties obliged Suriname to buy 700.8 GWh/year, corresponding to an average power output of 80 MW [58]; our simulations suggest an average electricity generation of 707.4 GWh/year, a difference of less than 1%. This supports the notion that the historical data can be taken as representative for present-day conditions for our purposes.

3.2. Wind power

To calculate wind power potential, the hourly-resolution 10-m wind speed in the period 1980–2018 was extracted from the ERA5 reanalysis [59] in the two grid cells containing Galibi and Nickerie (Fig. 1) and the 16 grid cells directly adjacent to those. Galibi and Nickerie were chosen

because (i) their wind climate is representative for the general conditions along the coast, and (ii) in-situ onshore wind speed measurements at 10-min resolution in the period 8/11/2009–8/11/2010 are available for both locations, which allowed for a statistical downscaling and bias-correction of the reanalysis data as documented in previous work [48]. After bias-correcting the data, the results were extrapolated to turbine hub height based on typical onshore roughness length values of 0.01 m along the coast.

All calculations pertaining to the conversion of wind speed to wind power generation were done on the basis of the power curve of Vestas V100-1.8 onshore wind turbines with a hub height of 95 m and cut-in, rated, and cut-out wind speed of respectively 3, 12 and 20 m/s [60] (see Acknowledgements). In all simulations, it was assumed that half of all wind power capacity would be deployed in (a location with similar conditions as) Galibi, and the other half in (a location with similar conditions as) Nickerie, to reflect generalised wind conditions along the coastline.

It is to be noted that limits on data availability meant that non-overlapping periods for the hydrological time series (section 3.1) and the wind speed time series had to be used. This implies that the effect of any potential covariance of hydrological and meteorological parameters cannot be discerned in our analysis. However, given the large storage potential of the Brokopondo lake, any such effects (e.g. simultaneous occurrence of high/low inland rainfall with high/low coastal wind speeds) presumably make no significant difference for joint hydro-wind operation.

This is, to the author's knowledge, the first application of the ERA5 reanalysis to Suriname. However, ERA5 data have already been applied to and validated for various other regions in assessments of wind power potential, notably for Sweden [61] and West Africa [62]. Our work thus adds to the burgeoning literature on ERA5 applications for renewable resource assessments [63].

3.3. Electricity demand

Electricity demand on the EPAR grid at hourly resolution was obtained from Suriname's utility company (EBS) for the period 2014–2018. Notably, nearly no net change occurred in total load during 2014–2018, with a mean of 1323 GWh/year and a standard deviation of $\pm 47 \text{ GWh/year}$, and no discernible increasing or decreasing trend. This near-zero change can be attributed to a gradual tariff raise in the rate schedule for electricity by the Surinamese government in 2015–2016, in conjunction with efforts to stimulate demand-side energy efficiency. This stabilised total grid load, which had been growing at 6% before this period. Nevertheless, Surinamese power demand may still grow substantially in the future, with growth rate projections of back up to 6%/year cited in literature [57]. This is further discussed in section 4.3.

4. Results

This section discusses simulation results pertaining to the power mix characteristics from hourly-to-multiannual time scales with joint hydro-wind operation (4.1), the economic advantages of wind power penetration through fossil-fuel displacement (4.2), and various sensitivity tests (4.3).

4.1. Power mix analysis

Fig. 5 shows results at hourly, seasonal and multiannual time scale from two example simulations, based on wind speeds from 2010 to 2018 (full time series) and the load profile from 2018 (assumed invariant from year to year). The outcomes were analysed for a very low acceptance of curtailment (1%, Fig. 5a–c) and a resulting deployed wind power capacity of 100 MW, and compared to the results under a higher acceptance rate of curtailment (13%, Fig. 5d–f) and a deployed wind power capacity of 200 MW.

Table 1

Technical hydropower plant data. List of characteristics of the Afobaka hydropower plant and the Brokopondo reservoir lake used in the simulations. * = Corrected for efficiency losses under part-load operation. The actual installed capacity is 189 MW; three of the units are fixed blades/adjustable gates (30 MW) while the three others are adjustable blades/adjustable gates (33 MW), which have broader discharge-peak efficiency ranges.

Quantity	Value	Unit
Rated capacity*	180	MW
Number of turbines	6	–
Reservoir volume	2.10×10^{10}	m^3
Lake area	1.56×10^9	m^2
Maximum head	55.6	m
Maximum ramp rate	36	MW/min
Power factor	0.95	–
Initial filling level	80%	–

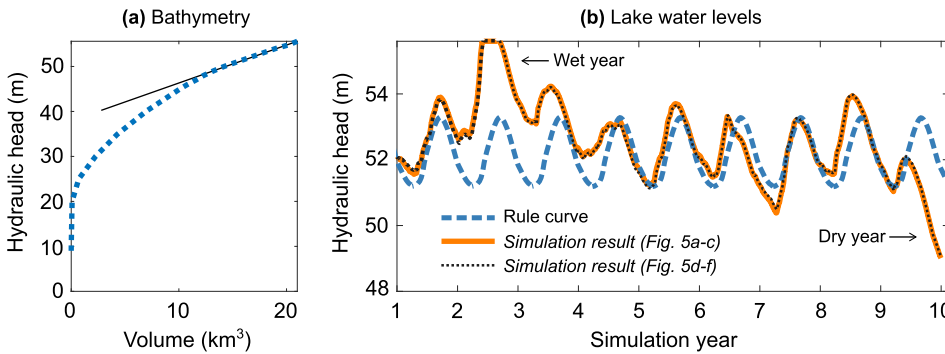


Fig. 4. Reservoir lake bathymetry and rule curve. (a) The bathymetric relationship between hydraulic head (the lake level elevation relative to the turbines in the powerhouse) and water volume in the Brokopondo reservoir. The solid line indicates the linear relationship by which the curve can be approximated ($[\text{head in m}] \approx 0.9096 \times [\text{volume in km}^3] + 36.715$; $R^2 = 0.992$) in the volume range spanned by the rule curve. (b) The rule curve of Brokopondo lake levels, to be followed as closely as possible in the simulations, shown for a nine-year period (dashed line). For comparison, the actual lake levels resulting from simulated joint hydro-wind operation (solid line and dotted line, corresponding respectively to the simulation settings in Fig. 5a–f) are also shown. The simulations ensure that the rule curve is followed to the extent possible, despite the occurrence of anomalously wet and dry years as indicated.

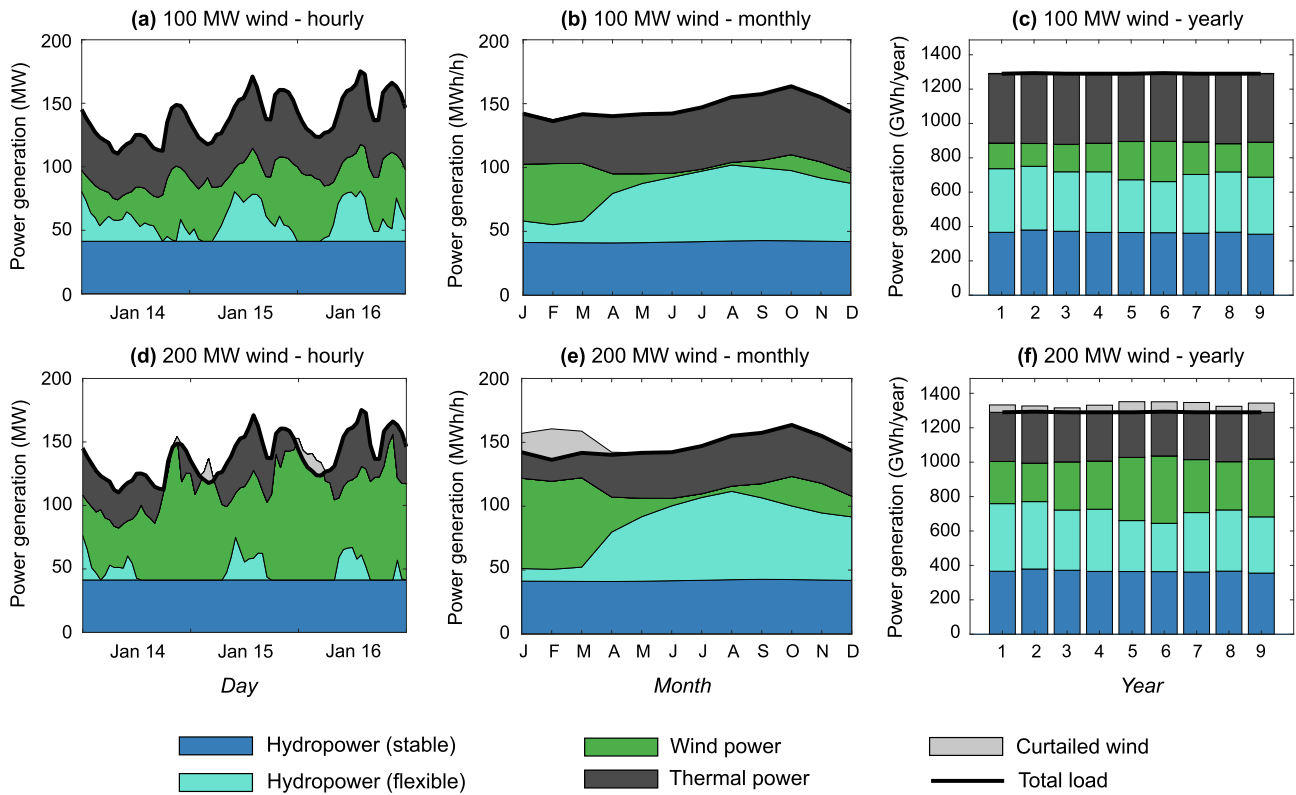


Fig. 5. Simulated hourly, seasonal and multiannual hydro-wind-thermal profiles. Total electricity generation mix as simulated based on 2018 load and 2010–2018 wind data, at hourly (left column; data from the first simulation year), aggregated seasonal (middle column; first simulation year) and multiannual (right column) resolution for two cases: with 100 MW (top row) and 200 MW (bottom row) wind capacity deployment. These optimised levels of wind power deployment are the result of the constraints on overproduction on the model, with near-zero curtailment in the former and 13% in the latter case. Categories are stacked from bottom to top in the following order: hydropower (stable), hydropower (flexible), wind power, thermal power, curtailed power.

The hour-to-hour power generation for an example time slice of the simulation (January 14–17 in simulation year 1; Fig. 5a,d) for both cases shows to what extent an increase in installed wind power capacity ensures better displacement of thermal power from the mix. The ramification of higher wind power feed-in is that more ramping from thermal power plants and more wind power curtailment will be needed to ensure grid stability (cf. the discussion from section 2.3), even though the hydropower plant already compensates for wind power variability to the extent possible.

The seasonal power generation profiles for both cases (Fig. 5b,e) highlight that accepting some curtailment can be an effective lever

towards consistently displacing thermal power, principally during the good wind season when the wind blows strongly but not always at the “right” times. Moving to the higher curtailment acceptance rate increases the wind power penetration in the months January to March from roughly 30% (Figure 5b) to 50% (Fig. 5e). During the long rainy season, wind speeds are too low to push substantial thermal generation from the power mix in either configuration. However, the more wind power infeed during the good wind season, the higher the hydropower potential will be during the long rainy season (since less water will have been used for flexible dispatch during the good wind season), and thus the more thermal generation can also be avoided in those months in the

second case.

At interannual time scales (Fig. 5c,f), the acceptance of higher rates of curtailment helps to carry the average wind power share in electricity generation from roughly 14% (Figure 5c) to 24% (Fig. 5f). Moreover, the flexible operational rules for hydropower ensure that the interannual variability of wind power generation is well-compensated by hydropower in both cases, despite interannual variability in the reservoir inflow itself (Fig. 4).

4.2. Economic implications

Following these two cases, the important question is how much thermal power can be displaced by wind power as a function of wind turbine deployment and accepted wind curtailment, and to what extent this would be economically advantageous. The latter can be inferred by considering the costs and gains involved, as follows. Wind turbine deployment, involving capital and operational expenditures but zero fuel costs, would displace a certain amount of power generation from existing thermal plants, and wind power overproduction/curtailment increase this displacement. However, wind power overproduction would not substantially reduce capacity requirements from thermal power due to the low capacity credit [64] of “overproduced” wind power (Fig. 3b). Accepting wind power curtailment to increase wind penetration thus primarily avoids “per-MWh” costs for thermal plants (fuel costs), but not “per-MW” costs (e.g. fixed operational/maintenance costs). An appropriate comparison to find the optimal level of wind curtailment is thus to weigh the curtailment-adjusted LCOE of wind power [65], which measures all costs of producing electricity from wind turbines including the cost of financing and operating the plant, against the avoided fuel costs for thermal plants [2]. Simulations spanning a wide range of curtailment rates (Fig. 6a) were therefore performed, and the corresponding displacement of thermal power (Fig. 6b), the curtailment-adjusted wind turbine capacity factor (Fig. 6c), and the

curtailment-adjusted wind power LCOE (Fig. 6d) calculated, in function of wind capacity deployment.

For joint hydro-wind operation with up to nearly 50 MW of installed wind power capacity, hydropower can perfectly compensate for all variability in wind power generation and no overproduction occurs (Fig. 6a, left vertical line; cf. Fig. 3a). Up to ~70 MW wind power capacity, some overproduction occurs but no curtailment is necessary for supply-demand balancing (Fig. 6a, right vertical line; cf. Fig. 3b). Beyond 100 MW, the curtailment rate increases at roughly 0.13% points per MW of deployed wind capacity.

As a consequence of this curtailment, the increase in the share of wind power in the electricity mix is not a linear function of installed wind capacity, but flattens off for higher wind deployment (Fig. 6b): while the first 100 MW of wind capacity can bring the share of wind in the power mix up by 15% points (i.e. from 0% to 15%), another 100 MW would increase the share by only 10% points (from 15% to 25%) due to necessary curtailment. The decrease in thermal power is proportional to the increase in wind power, thus dropping from the current average share of 47% at zero wind turbine deployment to 22% at 200 MW wind turbine deployment.

The annual average capacity factor of wind power in the assessed locations is around 21% according to the 2010–2018 wind speeds and with the assumed wind turbine type. However, beyond 100 MW of wind deployment, the curtailment-adjusted capacity factor drops roughly linearly at a rate of 0.03% points per deployed MW of wind capacity (Fig. 6c). This affects the expected LCOE of wind power, since the same investment and operational costs per MW will lead to fewer GWh fed into the grid per MW deployed. The LCOE of onshore wind power in Suriname was estimated based on the assumptions in Table 2, and the curtailment-adjusted LCOE was correspondingly calculated (Fig. 6d).

Comparing the latter to the historical fuel cost range for thermal power in Suriname (between 14.6 \$/kWh and 17.6 \$/kWh; see Acknowledgements), it can be observed that displacing thermal generation

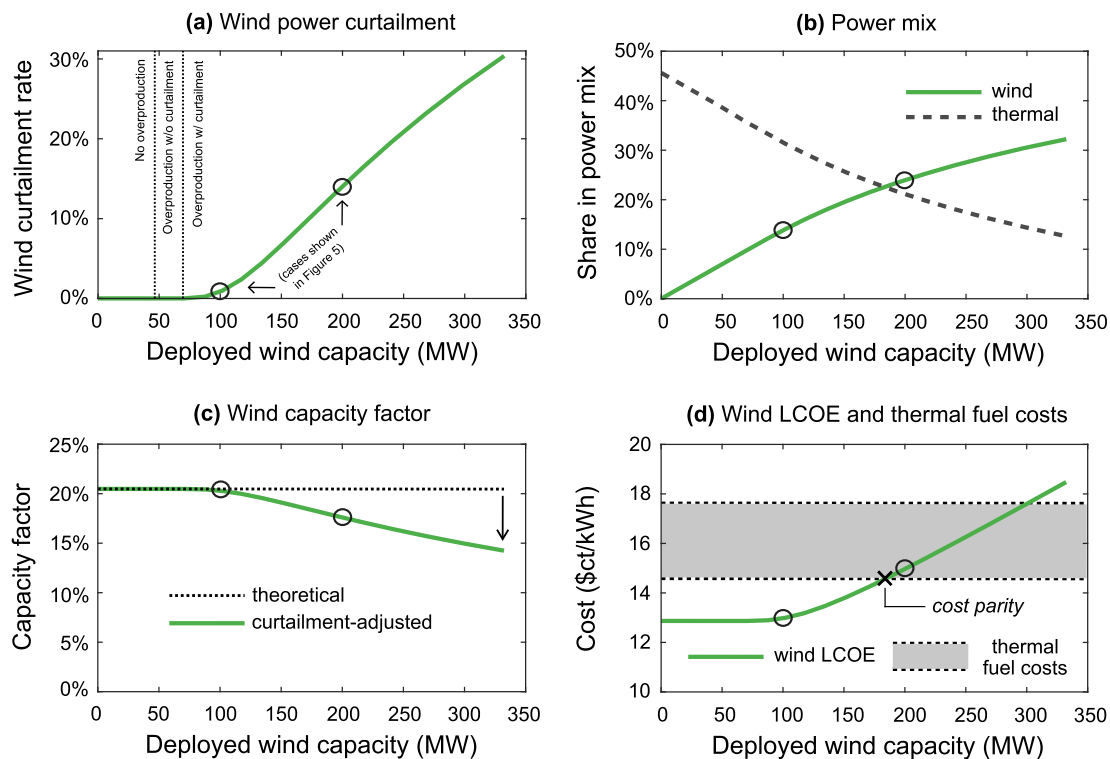


Fig. 6. The effects of increasing wind power curtailment acceptance. The amount of curtailed wind power (a), the share of wind power and thermal power in the electricity mix (b), the curtailment-adjusted capacity factor of wind power (c), and the curtailment-adjusted LCOE (Levelised Cost of Electricity) of wind power compared to the fuel costs of thermal power (d), all as a function of total wind capacity deployment. In (a), the ranges corresponding to situations (a)–(c) in Fig. 3 are indicated by vertical dotted lines.

Table 2

Assumptions used in the calculation of onshore wind power LCOE. CapEx = Capital Expenses; OpEx = Operational and Maintenance Expenses. *: Based on Brazil, the only neighbouring country for which data was available. **: Typical lifetimes for onshore wind turbines are around 20 years [68]. Given that the turbines proposed in this study would be located along Suriname's vulnerable coastal zone, whose infrastructures are susceptible to substantial risk of damages occurring due to flooding and coastal erosion [69], a more conservative 15-year lifetime was chosen.

Quantity	Value	Unit	Source
CapEx	1610	USD/kW	[66]
OpEx	43.6	USD/kW	[66]
Discount rate	10%	–	[67]*
Project lifetime	15	years	[68]**

with wind power would be economically advantageous up to at least 180 MW of wind turbine deployment, meaning that the avoided fuel costs would exceed the cost of curtailment [51]. This point, where the curtailment-adjusted wind power LCOE crosses the lower bound of historical fuel costs, is hereafter denoted “at cost parity” (Fig. 6d). Given the wide range observed for fuel costs and the relatively conservative assumptions (in terms of cost of capital and infrastructure lifetime; cf. Table 2) on wind power costs, this point represents a conservative estimate. At cost parity, wind curtailment rates would be around 10%, and wind would achieve a share of around 23% in the power mix, with a corresponding amount of thermal power being successfully displaced. A penetration of at least 23% of wind power in the electricity mix would therefore be technically feasible and economically advantageous for Suriname under the above assumptions, even without demand response and storage measures.

4.3. Sensitivity analysis

How sensitive is the above conclusion to assumptions regarding the load profile, selected wind period, and overall demand level? Load profiles may change from year to year depending on economic and climatic conditions; average wind speeds may shift on decadal time scales; and higher overall demand means lower need for curtailment at equal wind power deployment. The above analysis was therefore repeated for several cases: (i) using the load profile from each of the years in the period 2014–17 instead of 2018; (ii) using the wind speeds from each 9-year period preceding 2010–2018 (i.e. 1983–1991, 1992–2000, and 2001–2009); and (iii) using an adjusted overall demand level, assuming a growth rate of overall electricity demand between 0%/year and 8%/year over a 10-year period (thus representing possible demand levels around the year 2030).

Fig. 7 shows the sensitivity of wind power's (a) installed capacity and

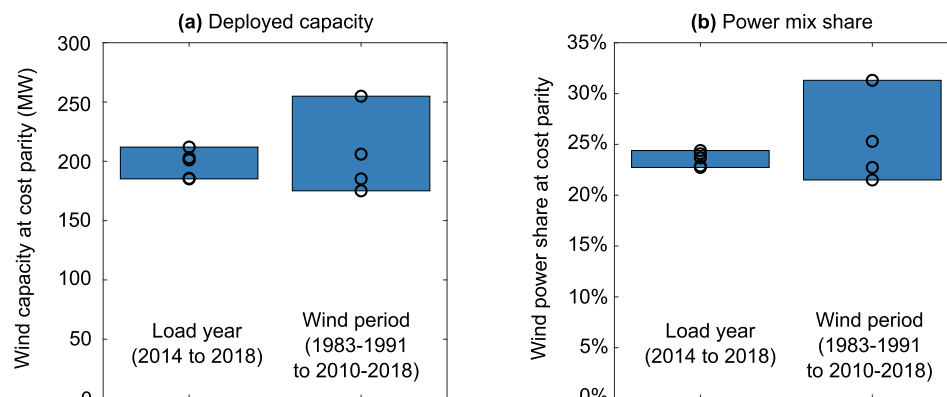


Fig. 7. Results of sensitivity tests for wind and load periods. Sensitivity of the installed capacity (a) and power mix share (b) of wind at cost parity with the cheapest thermal power to the choice of load year (left bars) and wind period (right bars) used in the simulations. The circles indicate the outcomes from individual sensitivity experiments; the bars the range spanned by these.

(b) power mix share at cost parity to the chosen load year and the chosen wind period. Clearly, the choice of load year has a relatively limited effect on the conclusions, reflecting the low change in power demand and typical hourly profiles observed in recent years. Contrarily, results are more sensitive to the chosen meteorological period for wind speeds: the average capacity factor of wind power based on the weather of the period 1983–1991, for instance, is around two percentage points higher than for 2010–2018, leading to higher yield per turbine, lower expected LCOE, and a wind power share of 30% at cost parity. This highlights the importance to undertake studies on potential future shifts in wind strength in Suriname as a result of natural variability and climate change; for instance, previous work has indicated that climate change may benefit wind power strength in Suriname [48].

Lastly, the effect of demand growth is shown in Fig. 8. While the wind turbine capacity deployable before reaching cost parity logically increases in line with the demand growth (assuming that the fuel costs for thermal power generation would not change, and that thermal power would remain the only alternative source next to hydro and wind), the corresponding share of wind power in the electricity mix is not very sensitive to this growth, at least when compared to the sensitivities to wind regime shown in Fig. 7. Assuming the demand growth estimate of around 6% cited in literature [48] would apply to the entire decade 2020–2030, wind power could be competitive with thermal power up to nearly 400 MW deployment by 2030 (achieving a 27% share in the mix), even assuming zero decrease in capital and/or operational and

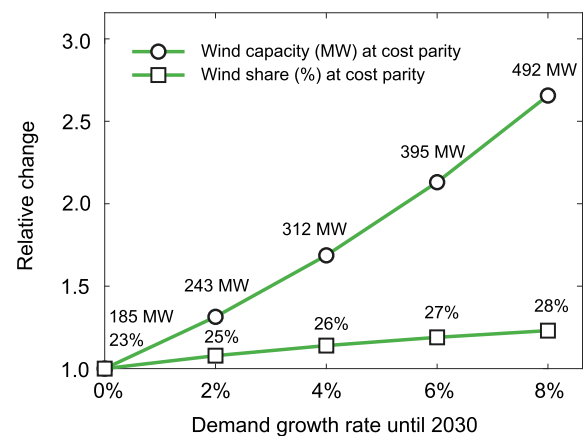


Fig. 8. Results of sensitivity tests for overall demand. Sensitivity of the installed capacity and power mix share of wind at cost parity to the demand level resulting from different growth rates over a 10-year period (i.e. from the present day until 2030).

maintenance expenses until then, which is highly unlikely [3].

Based on this sensitivity analysis, it can be asserted that a penetration of 20–30% of wind power in Suriname's electricity mix would be technically feasible and economically advantageous even without advanced flexibility measures such as demand response and/or battery deployment. Given that costs of wind power have been decreasing worldwide for many years and this trend is still ongoing [70], it appears certain that the above conclusions are conservative. As potential wind turbine deployment in Suriname would presumably happen in stages, the costs for each consecutive project could realistically be lower than for preceding projects as technology progresses and wind turbines with higher hubs (reaching higher capacity factors) become cheaper, allowing for penetration rates potentially beyond 30%. As more capacity for VRE is installed and experience gained in operating the grid, batteries and other forms of storage may become more relevant as a further backup source, allowing even more VRE penetration and providing additional grid ancillary services (see also section 5.3).

5. Discussion

This section discusses hydroturbine use (5.1), transmission infrastructure (5.2), and solar photovoltaic (PV) power (5.3). It also provides recommendations for future research, based on implications for other Caribbean countries and island states (5.4) and the Paris Agreement's long-term goals (5.5).

5.1. Hydroturbine usage

The more wind power is integrated into the power mix, the more ramping will be required from the hydropower plant (and from its thermal counterparts). The Afobaka hydro plant is equipped with six turbines of ~30 MW capacity (see Table 1). On average, the power output of the plant is around 80 MW [57] (see section 3.1); therefore, on average, three out of six turbines will be active. However, the ramping up and down in function of wind speed means that the number of instances with fewer or more active turbines will increase with wind turbine deployment, as shown in Fig. 9 (corresponding to the simulations in Fig. 5).

At 100 MW of installed wind power capacity (Fig. 9a), a majority of time (41.2%) would still be spent with three active turbines. However, at 200 MW of wind power (Fig. 9b), the amount of time spent with two (30.2%) or four (33.9%) active turbines would exceed the time with three active turbines (26.5%), reflecting the higher variability in wind power feed-in requiring more frequent up- and down-ramping of the hydro plant.

The high inactivity of half of Afobaka's turbines under current operation has recently been mentioned as a possible argument for

diverting further rivers into the Brokopondo lake to increase the water budget and avoid underutilisation of the available infrastructure [18]. As this study shows, joint hydro-wind management would be an alternative way of increasing the utilization rate of currently idle turbines, an effect that would become more pronounced the more wind turbines would be feeding into the grid. It could thus be argued that joint hydro-wind operation presents an avenue to avoid potential ecological damage of river-diverting interventions: it would increase the spread of turbine usage without changing the average water budget. While this would not increase the average power output of the plant, the wind power integration enabled by this flexible operation would compensate for the lack of increased hydropower output that further river diversions could have brought. Hydro-wind integration can therefore synergise well with ecological sustainability objectives [20].

Another option to increase hydroturbine usage while avoiding upstream river diversions would be to create a smaller second artificial lake downstream and retrofit the Afobaka plant with a wind- or solar-powered pumping station, converting the plant to a pumped-hydro "battery". During periods of high VRE generation, part of the power could be used to pump water from the smaller reservoir back into the Brokopondo lake, effectively storing the electricity as increased hydro-power potential [71,72]. Whether such a project would be infra-structurally feasible, and what the technical/design characteristics would have to be (lower lake size, pumping power, etc.), could be the subject of future studies. The REVUB model, which has a pumped-storage module, could then be used to estimate the corresponding increase in potential for fossil fuel displacement [20].

5.2. Role of transmission capacity

The wind speed time series used in this study can be seen as representative of wind conditions all along the Surinamese coast. To cost-effectively deploy substantial wind capacity in Suriname, locations as close to the existing grid as possible should be preferred to avoid high upfront transmission line costs. A suitable potential location for initial projects could be Weg naar Zee, a coastal locality around 20 km from the center of the Surinamese capital Paramaribo (Fig. 1) where the EPAR grid is already present.

As our results have shown, with the current island-like configuration of the EPAR grid, some wind power curtailment will likely have to be accepted if high wind power penetration is to be reached in the absence of storage. However, in the future, overland transmission lines connecting Suriname to neighbouring countries/regions, notably Guyana, French Guiana, and the Brazilian states of Roraima and Amapá [73], could be a lever towards avoiding curtailment, allowing to export any renewable power not needed in Suriname. It could also help create a business case for Suriname around flexible export of hydroelectricity to

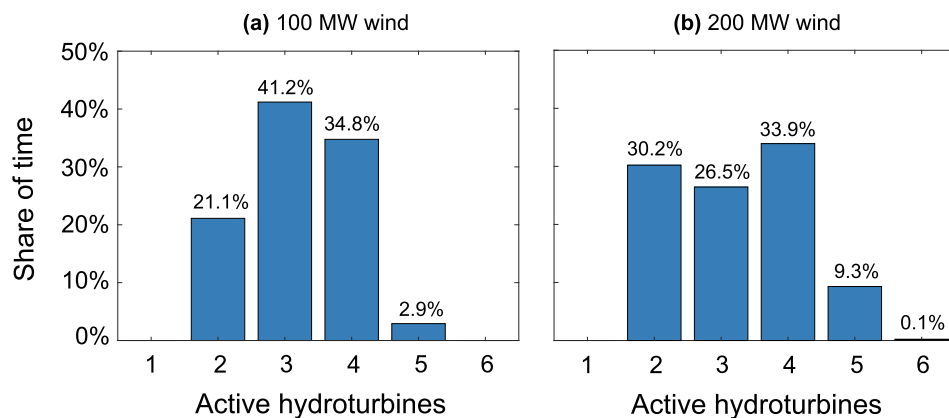


Fig. 9. Hydroturbine use. Hydroturbine utilization rate for the same two cases of wind power infeed shown in Fig. 5: (a) with 100 MW wind capacity; (b) with 200 MW wind capacity.

other regions dealing with temporary generation shortfalls [11,20,73].

5.3. Role of solar PV

Next to wind power, solar PV has also been suggested as an important technology for decarbonising Suriname's power mix in the future [11,15,45]. The LCOE of solar PV power has experienced very sharp downward trends, globally as well as in South America, in the recent past that show no signs of abating [11,70]. However, two factors lead us to conclude that in Suriname's specific case, wind power is a more obvious candidate to be supported by hydro-driven flexibility than solar power. Firstly, there is no real seasonal hydro-solar complementarity in Suriname, with a year-round cloudy climate and minimum irradiation levels occurring in the period December–April (below 5 sunshine hours/day) [74], coinciding with the period of decreasing water levels in Brokopondo. Secondly, the cloud- and thunderstorm-driven minute-to-minute intermittence of solar irradiation in Suriname is very high and present year-round; this would put substantial strains on hydropower dispatch on very short (sub-minute) time scales [2], which would be further compounded by the fact that irradiation variability is highest in the same period December–April when average irradiation is lowest [74] and when the lake water level drops to its minimum.

Nevertheless, it is clear that solar PV should be part of Suriname's long-term energy policy [11,15,45]. The deployment of solar home systems and off-grid solutions could be promising, especially for Suriname's interior areas. On a larger scale, battery storage, pumped-hydro storage, and demand response (e.g. through sectoral coupling) could be feasible candidates to facilitate electricity mix integration of solar power. In particular, battery storage systems may become an important future asset for providing frequency support at high solar penetration once their costs have sufficiently declined, owing to their superior (millisecond-to-second) response times when compared to conventional spinning generation [2]. More research on solar PV potential and its use cases in Suriname in combination with battery storage is therefore recommended.

5.4. Implications for other Caribbean countries and island states

Hydro-supported integration of VRE could be interesting for various other Caribbean countries and territories. Substantial hydropower capacity is currently available in the Dominican Republic, Jamaica, Haiti, Belize and Guadeloupe, while there is large unexploited hydropower potential in Guyana [75]. Although river discharge, reservoir areas and water budgets for hydropower on the Caribbean island countries are clearly of a smaller scale than for Brokopondo in Suriname's interior, rugged island geography often allows for much higher-head sites than Afobaka. All these Caribbean regions, whether island or continental, could therefore likely make smart use of hydropower's contributions to grid inertia and flexibility to support increased penetration of renewable resources such as wind and solar power, potentially in combination with pumped-storage solutions.

Wind power potential is high along the coastlines of most Caribbean island countries, and typically follows comparable seasonal (trade wind) patterns to Suriname [76]. Solar power potential is also widespread, with most Caribbean countries, including the Dominican Republic, Jamaica, and Haiti, having lower cloudiness and lower irradiation intermittence than Suriname. For instance, Jamaica is already exploiting both wind and solar power, for which research on grid integration is ongoing [2]. We therefore recommend comparable studies on hydro-driven flexibility to be undertaken for at least the Dominican Republic, Jamaica, Haiti, Belize, Guadeloupe and Guyana. Depending on each country's nationally available resources, these could focus on hydro-wind [29,41–43], hydro-solar [34–39], or hydro-wind-solar synergies [20,30–33].

Outside of the Caribbean region, various Small Island and Developing States and other island territories could also benefit from such

complementarities. We mention Fiji, Samoa, the Solomon Islands, Papua New Guinea, New Caledonia, Madagascar and Greenland as potentially interesting case studies with existing and/or potential hydropower capacity [75] and without the option of large-scale interconnected grids as lever for high VRE take-up.

5.5. Outlook for climate policy and recommendations

Energy systems worldwide must have largely decarbonised by mid-century if the goals of the Paris Agreement are to be met [1,45]. Which are the most important options for Suriname to reach “100% renewables” in the long term (beyond the 2030 horizon of the present study), fully pushing thermal generation from the mix while also decarbonising other sectors? Firstly, there remains unexploited hydropower potential in Suriname, mostly in the Kabalebo river basin where power generating capacities of a similar order as Afobaka would be feasible [77]. Exploiting this potential would also enable further hydro-supported take-up of VRE, which could thus function as the backbone of long-term climate policy strategies even under rising power demand. Secondly, future drives for electrification, coupling the transport, buildings and industry sectors to the power sector alongside storage technology deployment, could help decarbonise those sectors while increasing VRE potential by widening the scope for demand response [78]. The authors of this paper are currently planning a follow-up study for Suriname to investigate the potential of these options.

However, future climate change may itself affect the availability of renewable resources. For instance, under continued trends of global warming, the hydropower potential of the Afobaka plant may be negatively affected [57], but wind regimes along the Surinamese coast may increase in strength [48]. Climate change-related changes in solar irradiation [79] and hourly load profiles [80] can be expected as well. We therefore recommend studies on the climate change impact on hydro, wind, solar, and load to accompany any study on renewables' integration potential to support integrated resource and resilience planning (IRRP). The aforementioned follow-up study on Suriname will include such investigations.

Lastly, such follow-up work could also consider the potential economic implications of increased VRE deployment in more detail. As discussed, substantial oil-based fossil fuels can be cost-effectively displaced from Suriname's power mix by a combination of existing hydropower infrastructure and near-grid wind power. However, future VRE growth and new hydropower development may necessitate transmission grid expansion, e.g. merging the EPAR grid with Suriname's various smaller grids [15], entailing substantial costs. Further, an eventual regional integration with power grids of neighbouring states may need to explicitly take into account remunerations for flexibility services delivered by hydropower, such that hydropower exports could constitute a business case for Suriname [11,73]. Trade-offs between upfront costs to support VRE expansion and avoided fossil fuel costs could then be assessed in a regionally integrated manner.

6. Conclusion

Based on high-resolution data regarding reservoir inflow, evaporation, wind speed, and electricity demand in Suriname, this study leads to several conclusions. Firstly, the Afobaka hydropower plant, newly in Suriname's full possession, can support the power mix integration of substantial amounts of wind power, thanks to its flexibility of dispatch and the strongly present seasonal hydro-wind complementarity. Secondly, accepting limited amounts of curtailment during the good wind season can be an effective lever to increase wind power penetration. Given conservative cost estimates for wind power and historically observed fuel costs for thermal power, displacing thermal with wind would remain economically advantageous up to wind curtailment levels of around 10%. Thirdly, taking into account interannual-to-decadal variability in wind speeds, this corresponds to a deployed wind power

capacity in the range 175–250 MW and wind power generation of 300–460 GWh/year given present-day demand. The resulting share of wind power in Suriname's power mix would lie in the 20%–30% range. Fourthly, the latter number is relatively insensitive to future demand growth rates.

Such a level of wind power penetration would represent a considerable displacement of thermal power from the power mix and a corresponding decrease in greenhouse gas emissions. It would also guarantee Suriname to well overshoot its Nationally Determined Contribution (NDC) target of 35% renewable electricity generation by 2030. We therefore conclude that planning for the deployment of coastal onshore wind power, with up to at least ~200 MW of total capacity given current demand levels, represents a no-regret option for Suriname.

Given the island-like nature of Suriname's main grid, these methods and results also provide starting points for investigating comparable synergetic hydro-wind-solar planning in several other Caribbean countries and island states.

CreDiT Statement

Sebastian Sterl: Conceptualisation, Methodology, Writing - original draft, Data curation, Formal analysis, Investigation, Project administration, Software. Peter Donk: Conceptualisation, Methodology, Data curation, Investigation. Patrick Willems: Writing - review & editing. Wim Thiery: Writing - review & editing; Fund Acquisition.

Data and code availability

The REVUB code application used for this study, and the data used as input, are available via https://github.com/VUB-HYDR/2020_Sterl_etal_RSER. The code and manual for the REVUB model itself are available via <https://github.com/VUB-HYDR/REVUB>.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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