Integrating supply and demand-side management in renewable-based energy systems

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A B S T R A C T

Demand-Response (DR) has emerged as a valuable resource option for balancing electricity supply and demand. However, traditional power system models have neglected to include DR within long-term expansion problems. We can summarize our scientific contributions in the following aspects: (i) design of a new integrated co-optimization planning model for supply and demand coordination; (ii) assessment of the technical and economic impact of DR for systems with a high share of Renewable Energy Sources (RES) and (iii) proposal of the 'opportunity cost' concept for computing the price of not meeting the demand. Findings of this research support the hypothesis that DR scenarios reveal a high potential for delaying future investments in power capacity compared to scenario BAU (Business as Usual). However, it was found a limited potential of DR to integrate additional renewable plants. This research has provided further evidence concerning the potential of DR to decrease the levels of CO_2 emissions that is strictly related to the reduced need for fossil fuel thermal power plants. Given the high RES share, uncertainties related to future weather conditions must be however highlighted. This study concludes on the importance of DR for power systems planning and lays the groundwork for future research.

1. Introduction

1.1. Literature review

The increasing reliance on clean energy supply options [1] and the emergence of Demand Response (DR) measures in smart power systems have attracted considerable critical attention of researchers and society, mainly in the last decade [2]. DR has emerged as a valuable resource flexibility option for balancing supply and demand and consequently enhancing the overall level of power systems' flexibility, but it has also been recognized as a new market opportunity for consumers. It is well established the need to enhance the power system flexibility as the stochastic production from VRE increases [3]. The mismatch between production and demand may cause over-voltages, equipment tripping or even blackouts since it affects the power system frequency [4]. The load balancing (or net-load balancing) refers to the power system's ability to match demand and supply in a smart grid environment [4].

Short-term power system models such as unit commitment and economic dispatch have been traditionally used to assess the impact of RES integration on power system operation. These models are usually focused on issues related to power system security or flexibility adequacy [5,6]. In the context of power systems, the term "flexibility" can be broadly defined as "*the ability of a power system to cope with variability and uncertainty in both generation and demand, while maintaining a satisfactory level of reliability at a reasonable cost, over different time horizons*" [7]. The concept of flexibility might be split into short-term (i.e., *flexibility adequacy*[1]) and long-term (i.e., *system adequacy*[2]) [6].

The use of long-term power system models (e.g., Generation Expansion Planning - GEP) has been traditionally employed and

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[1] Flexibility adequacy refers to "*the short-term ability to keep the system balanced*" [6].
[2] System adequacy refers to the power system's long-term ability to meet its peak demand [5,6].

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best suited to address system adequacy issues and assess the impact of RES integration on power system planning. Conventionally, GEP models do not include significant temporal and operational detail, which usually leads to an oversimplified representation of short-term system operation and its costs [6]. The high RES integration in power systems in general, concerns related to short-term operating requirements and constraints (i.e., flexibility adequacy) have also attracted strong research interest and should be assessed carefully to ensure a reliable and resilient power system planning [5,6]. The short-term operation is then becoming increasingly essential to be considered in long-term power planning. The importance of combining short and long-term power planning is addressed by Ref. [8], focusing on the Portuguese electricity system. However, the computational barriers associated with large power systems have usually limited the inclusion of short-term operating requirements in long-term planning models [6].

Traditional power system models have neglected to include DR strategies within long-term power generation expansion planning problems [24]. These conventional models have been usually focused on the expansion of the supply-side. However, researchers have dedicated valuable efforts to model and assess the impact of DR measures not only in the short-term but also in long-term power planning studies. Ref. [9] supports that "*DR represents a paradigm shift in how we view electricity markets since electrical load can now appear on both sides of the supply-demand equation*". The use of DR strategies has been considered by Ref. [10] focused on the Texas power system's long-term model.

The reserve margin impacts have been recently addressed by Ref. [11], which takes into account the use of both DR measures and energy storage systems and also considers the impact of different shares of wind power. With the increasing wind penetration, reserve margin reductions have been observed for the power system evaluated by Ref. [11]. The load management benefits focused on the CO_2 emissions reduction was particularly addressed by Ref. [12] for the Swedish power system. Recently, Ref. [13] proposed an accurate and generic formulation regarding the use of operational constraints in DR modeling to obtain more accurate results and surpass previous DR limitations. The proposed enhancements included, for instance, restricting maximum hourly upward and downward shifts and constraining the maximum number of daily DR events.

Therefore, a growing body of literature recognizes the importance of integrating supply-side and demand-side options in long-term power system planning studies. The analytical frameworks to incorporate DR in long-term resource planning models have also been recently investigated [14]. A set of recommendations (e.g., assessing the optimal DR portfolio and accounting for the geographical distribution of DR participants) for incorporating DR as a competing resource option was proposed by Ref. [14]. The authors highlighted that some utilities located in the U.S. have been considering the inclusion of DR measures in planning models as resources that compete with traditional supply-side options when determining the optimal mix for the future, pointing out that this strategy might lead to a least-cost resource portfolio [14]. Ref. [15] also dealt with DR under long-term resource planning by proposing a generic optimal planning model. The technical effectiveness from the implementation of DR strategies has been particularly addressed by Ref. [16], focused on using DR to mitigate the variability in the energy system of Finland. The impact of operating reserve requirements on the installed generation mix of a power system with high RES integration is addressed by Ref. [5]. However, this latter work does not consider using DR strategies and storage technologies in the problem formulation. Findings of the study proposed by Ref. [17] indicated that generation dispatch and investments might be affected by the inclusion of demand-side strategies or storage technologies within the optimization model. The procedure carried out by Ref. [6] addressed the role of storage in future RES-based systems using a long-term generation expansion planning model. The role of storage for the integration of RES in future power systems is also discussed in Ref. [18]. Ref. [19] analyzed the main institutional challenges caused by the integration of VRE in the European electricity sector. A comprehensive review study was also recently performed by Ref. [20] addressing the GEP problem's multi-dimensionality. The integration of RES, storage technologies, and flexible load into the German power grid has also been investigated in the work of Ref. [21].

Based on the previous contextualization, it can be seen that much of the attention in previous research has been to consider the technical impacts of RES on power grids [22,23] and most of the previously published works have focused on the short-term impact assessment of DR strategies. However, little research has focused on determining the long-term impacts of DR implementation, such as evaluating changes in the future optimal base power capacity and peak system load as a consequence of the implementation of such policies [14,24].

1.2. Motivation and contribution

Although the literature has extensively addressed the impact of RES in the long-term, research has yet to systematically investigate the effect of both high RES integration and the use of DR measures for the long-term. In contrast to the previous works, the relevance and innovative aspects of this study are then strongly related to the integrated assessment of DR into renewable-based energy systems. Therefore, this paper follows a novel approach and the contributions to the new body of knowledge from the international perspective comes from the proposed modeling approach. The proposed enhancements in the co-optimization model for long-term decision-making allow integrating the short-term variability of both demand and RES supply, making the model well suited to systems with a high share of RES and for different demand flexibility conditions. This combination makes the proposed model unique and challenging to solve and is expected to result in a powerful tool to guide and support policy-makers and stakeholders. The integrated assessment of both supply and demand-side strategies within the same model calls for an innovative approach usually referred to as 'co-optimization'. According to the definition proposed by Ref. [17], "*co-optimization is the optimization of two or more different yet related resources within one planning framework."*

In this regard, compared with previous studies, we can summarize our theoretical contributions in the following three aspects:

- Design of a co-optimization model for supply and demand coordination, resulting in a new integrated planning model particularly well suited to systems with a high share of RES and under different demand flexibility conditions.
- Assessment of the technical and economic impact of DR measures for systems with a high share of RES.
- Proposal of a concept of the so-called opportunity cost for computing the price of not meeting the demand (i.e., for load shedding) based on each region's spot price.

Therefore, the efforts of this paper are then focused on answering the following research question: *How would cost-optimal pathways change with the inclusion of DR measures within the co-optimization model?* The assessment is conducted based on a renewable-based energy system with a particular focus on the potential of DR to (i) decreasing power generation capacity; (ii) RES integration; (iii) delay in investments; (iv) reduced need for thermal capacity; (v) decrease in the level of CO_2 emissions, and (vi) the possibility of enhancing the synergies between power subsystems within the country. The objectives are explored for the case of the Brazilian power system, which can be justified by the following factors: (i) continental dimensions; (ii) high RES share; (iii) vulnerability to climate change and (iv) access to data. Although the analysis is carried out focused on the complex and non-trivial Brazilian power system - which is highly interconnected and supplied mostly by RES - the proposed methodology can be further extended to assessing other power systems with both high RES penetration and under different flexibility requirements.

The overall structure of this paper is divided into six main sections. This first section provides a brief contextualization of the topic under study. Section 2 attempts to describe the methodology used along with this research, including the proposed model enhancements. The main findings are then presented in Section 3, with a lively discussion of the results in Section 4. Section 5 summarizes the main conclusions and Section 6 outlines the study's main limitations underlining possible avenues for future research.

2. Methodology

A broad literature review was first undertaken to develop a clear argument based on a constructively critical analysis of the literature recently published. What is not yet fully clear is the extent to which DR may be cost-effective. This task is technically challenging for the particular case of developing countries mostly because of two aspects (i) the data scarcity regarding the potential of DR among sectors and (ii) the lack of infrastructure, which makes more difficult the cost estimation for implementing DR (for both investment and operational costs). After conducting a comprehensive literature review, the research gap was identified as described in the introduction. Data collection techniques used in this research include examining multiple-source primary and secondary data. It will be collected predominantly on online computer databases from both official electricity institutions and expert reports. Specific information for hourly demand of each region within the country is retrieved from online databases of official Brazilian electricity institutions such as the Energy Research Office (in Portuguese, EPE) and the National Grid Operator [25] (in Portuguese, ONS). The use of computational simulation is used within the research strategy to assess DR's long-term effects for systems with a high share of RES and under different demand flexibility conditions. The Brazilian power system is used as the case-study since it is an example of a power system that relies mostly on RES.

The detailed model structure of the research is summarized in Fig. 1. The premises undertaken to build the model have been based on the primary evidence for the future of the power sector which is projected to rely on two main pillars: (i) the new hydropower projects are expected to be dominated by run-of-river power plants and (ii) a high increase in household solar PV systems is foreseen. Therefore, these particular aspects envisioned for the country in the years ahead are considered in the input data modeling.

The methodological assumptions regarding the existing and forecasted theoretical DR potential in the country are based on previous research [26,27]. The theoretical DR potential is used as part of the model input data and it can be assessed by identifying the most suitable appliances and processes for DR followed by the assessment of the load profiles for each sector and finally by quantifying each flexible load (see Refs. [26,27] for more details). The overall future mix of generation is planned by taking into account the contribution of DR strategies. The assessment is quantitatively assessed based on the forthcoming impacts for the costs, CO_2 emissions and installed capacity considering the planning horizon from 2018 to 2040 and focuses mainly on evaluating the long-term effects of implementing a set of DR measures in the country (i.e., load shedding and load shifting) that competes with traditional supply-side options.

2.1. Integrated co-optimization modeling

The co-optimization problem of this study is subjected to a large number of technical, economic and environmental constraints used to attend to the system requirements derived from physical processes and capacity limitations but also to ensure minimum levels of reliability and security for the electricity system [28e30]. The objective function of the long-term generation expansion planning model accounts for the minimization of the total discounted costs[3] of each technology (t) and each year (y). These costs are composed of the capital, operating, fuel, CO_2 emissions as well as the expenses related to the DR implementation (i.e., load shedding[4] and load shifting).

The model is split up into ninety-six time-slices[5] used to represent the demand/supply characteristics of each year of the planning period considering the four seasons (Summer, Fall, Winter, and Spring). Each season is divided into twenty-four daily time brackets representing each hour of a typical day in each season. The specified demand profile for each time slice was calculated based on the hourly data extracted from the National Grid Operator for 2018 [25]. The high-resolution dataset for representing the temporal model resolution is considered worthwhile. However, the computational complexity associated with the modeling approach is strongly affected as the time-resolution increases [31]. For this reason, the use of time slices to represent the temporal resolution of long-term models has been increasing over the years since this approach may significantly reduce the computational requirements. This practice is especially worthwhile for long-term capacity planning [32], but its importance is even more remarkable when short and long-term model integration is required.

The integrated co-optimization modeling approach used along with this research is based on the Open Source Energy Modeling System (OSeMOSYS) implemented in the General Algebraic Modeling System (GAMS) software through linear programming. Additional information about the modeling assumptions and the full OSeMOSYS model description can be obtained at www.osemosys.org and in Refs. [33e36]. Along with this paper, the term 'Integrated' refers to the joint implementation of both supply and demand-side resources into the same co-optimization approach. The Integrated Brazilian Electricity System Model (IBESM) proposed in this research comprises the integration among (i) the original OSeMOSYS code [35] (translated initially into GAMS by Ref. [37]) with (ii) the inclusion of a set of DR strategies based on the code improvements proposed by Ref. [32]. Therefore, we combined these models into a single integrated model in GAMS with additional code enhancements, such as illustrated in Fig. 2.

The proposed framework (Fig. 2) can be split into three main parts: Part I (model enhancements), Part II (model integration), and Part III (model evaluation), whose description follows.

PART I e MODEL ENHANCEMENTS.

[3] In this study, all the costs are discounted back with a predefined discount rate assumed to be equal to 9%, on Refs. [46,56].

[4] Also known as 'load curtailment' [4].

[5] The time slices have as the main aim to combine representative times within a year [32]. One time slice could represent, for instance, all the weekdays mornings in winter and another one the weekend evenings in spring. Time slices would also support the integration between supply and demand-side resources under long-term optimization models. The use of linear optimization techniques coupled with time slices leads to shorter computational solution times.

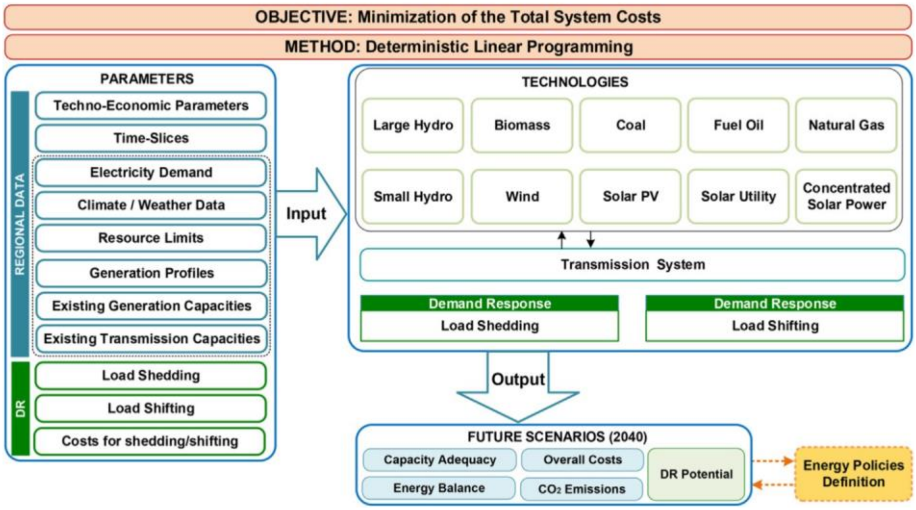


Fig. 1. Detailed modeling approach followed in this research.

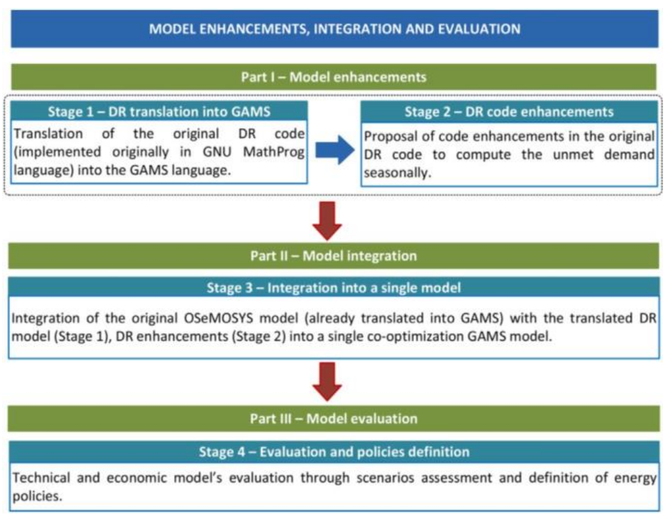


Fig. 2. Model enhancements (Part I), model integration (Part II) and model evaluation (Part III).

Stage 1 e DR translation into GAMS.

The translation of the original DR code (implemented originally in GNU MathProg language [32]) into the GAMS language is provided in Stage I. Two strategies are considered for DR implementation in Ref. [32], i.e., (1) load shedding (also referred to as prioritizing demand types [32]or even load curtailment [4]) and (2) load shifting, which are described along with this section.

(1) DR strategy - Load shedding

The prioritization of specific categories of loads may be envisaged aiming to provide flexibility to the power system. This prioritization (also referred to as load shedding) can be implemented by the utility or the consumer depending on the employed load control technique (e.g., Direct Load Control, Local Load Control, or Distributed Load Control). The model extended by Ref. [32] allows leaving a predefined demand category (set 'FLEXIBLEDEMANDTYPE') unmet in the case the cost for supplying it exceeds a value defined by the parameter 'PriceOfUnmetDemand(r,f,ls,fdt,y)'. Literature usually refers to this parameter as the Value of Lost Load (VoLL) or the cost of unserved energy. It is worth mentioning that this cost could be understood as the baseline cost in which it would be cheaper to curtail the load instead of meeting it by other means such as by other power generating sources. For our research, this value has been established based on the concept of the so-called opportunity cost. The opportunity cost can be defined as "*the value of the next best alternative that the decision forces the decision-maker to forgo* [38]". Therefore, the price of not meeting the demand (i.e., for load shedding) can be considered a cost of an opportunistic planning strategy. In our case, the opportunity cost refers to the opportunity of shedding the load during a predefined time and subjected to a particular variable cost (US$/MWh), which is based on the spot price of each region.

(2) DR strategy - Load shifting

The original set of equations proposed by Ref. [32] for load shifting are considered in our model. We attempt to translate these set of equations into GAMS language. Load shifting is implemented considering that each process/appliance can function with a 'storage' ability during a predefined time. Once the original demand is reduced, the storage is charged. However, when the demand is met again, the storage is discharged, increasing the original demand during that period. The maximum time allowed for each flexible load to be met earlier (or in advance) or later (or delayed) should be defined through the 'MaxAdvance(fdt)' and 'MaxDelay(fdt)' parameters, respectively.

Stage 2 e DR code enhancements (GAMS).

Stage 2 proposes enhancements in the original DR code. These code enhancements are proposed to compute the unmet demand seasonally since the original model computes the unmet demand for the entire year. Therefore, the upgrades are explicitly linked with the load shedding strategy and are described in Fig. 3.

The key focus of the proposed enhancements in the original DR code [32] is based on the addition of the index 'ls' - representing each season of the year - over the original parameter 'PriceofUnmetDemand(r,f,fdt,y)' which now becomes 'PriceofUnmetDemand(r,f,ls,fdt,y)' (Step 2.1 in Fig. 3). This revised parameter allows now to insert data specifically for each season of the year. This is particularly important for systems with both a high share of RES and continental dimensions in which the spot prices vary significantly among regions and seasons, such as the case of the power system evaluated in this research. A new variable is also included within the original model called 'CostOfUnmetDemandSeasonal(r,ls,fdt,y)' (Step 2.2). This new variable is used within the model in a new equation, responsible for computing seasonally the price

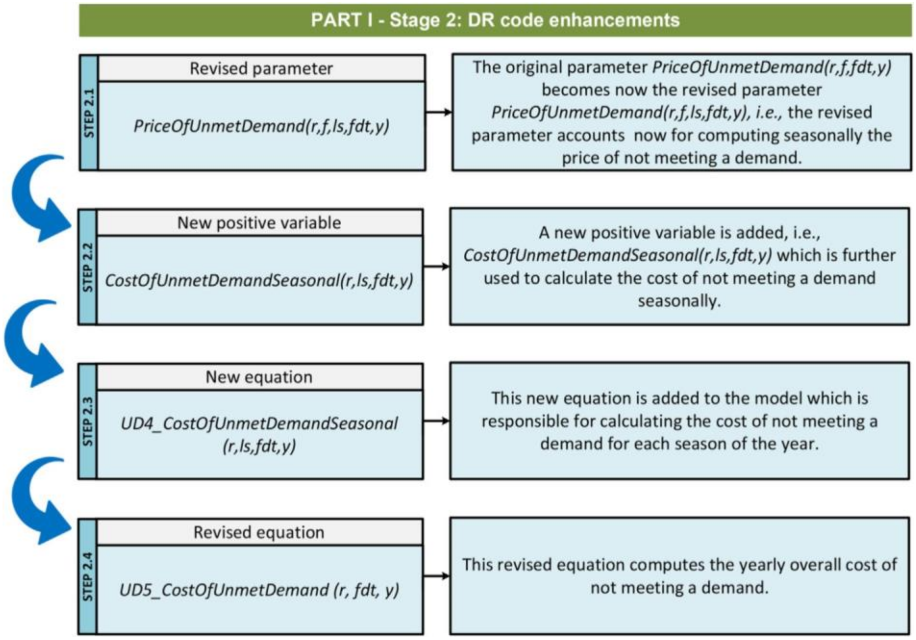


Fig. 3. Enhancements in the DR code (Part I - Stage 2).

of not meeting a demand (Step 2.3). The overall cost of not meeting the demand is then calculated in Step 2.4.

PART II e MODEL INTEGRATION.

Stage 3 e Integration into a single model.

This stage comprises the integration of the original OSeMOSYS model (already translated into GAMS Ref. [37]) with the translated DR model (Stage 1), DR enhancements (Stage 2) into a single co-optimization GAMS model.

PART III e MODEL EVALUATION.

Stage 4 - Evaluation and policies definition.

The last stage of the proposed framework (Stage 4) addresses the technical and economic evaluation through scenario assessment. Last but not least, the energy policies definition can be further established for each scenario, such as suggested by the proposed framework.

2.2. Main model assumptions

The analysis carried out along with this paper aims to address the least-cost capacity expansion plan considering the contribution of both supply-side and demand-side strategies. A particular focus on assessing DR measures' contribution (load shedding and load shifting) is taking into account from the demand-side. The assessment is split into two main parts: (i) the technical DR potential evaluation is conducted, followed by (ii) the economic DR potential assessment.

For both assessments (technical and economic DR potential), the theoretical load flexibility potential addressed by Ref. [27] is used as the basis for the input data of the co-optimization model. The five-step methodology for assessing the theoretical load flexibility potential in the power system is illustrated in Fig. 4 [27].

Ref. [27] evaluated the theoretical[6] DR potential for the Brazilian power sector across residential, commercial, and industrial segments by considering the specific flexible demand profiles for each sector, based on the average demand profile and considering the real data extracted from ONS [25]. The authors of Ref. [27] also considered a regional and sectoral scope (dividing into processes/ appliances suitable for DR) in their assessment. In our case, the estimation of both the technical and economic DR potentials is undertaken by also considering a regional analysis, but the sectoral assessment is evaluated by aggregating each sector's individual processes and appliances. This sector's aggregation is required because of the high computational times needed to solve the optimization problem, since not grouping the individual processes/ appliances increases the number of variables and constraints included in the model. We also considered that 100% of the load flexibility potential could be used for DR, although a further study focusing on evaluating different shares (e.g., for each sector and year) is highly recommended.

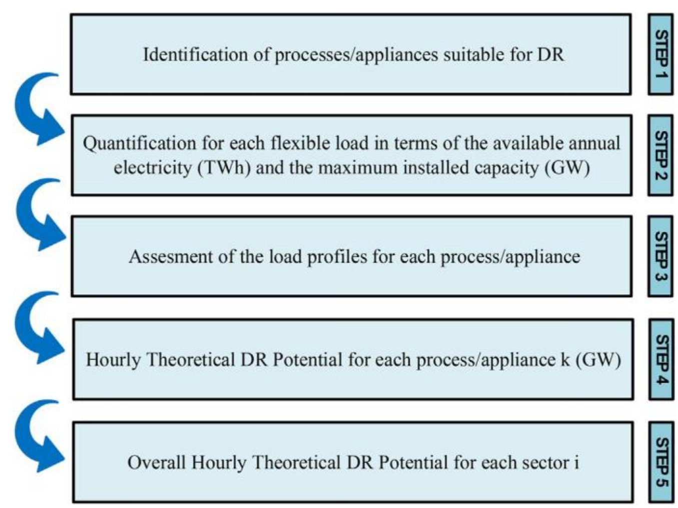


Fig. 4. Methodology for the assessment of the theoretical load flexibility potential ([27]).

[6] Findings of Ref. [27] revealed an overall increase from 12.8 GW (2017) to 25.6 GW (2050) in the overall theoretical load flexibility potential in Brazil and the major part of this load flexibility potential seems to lie in the industrial sector. The study also revealed a lower but still high DR potential for the commercial and residential sectors. Particularly for the residential sector, the high theoretical load flexibility potential comes from both the number of households and the number of appliances per house and more than half of the overall potential is supposed to come from the refrigerators.

To evaluate the technical DR potential (scenario DR^T), no costs are considered for DR implementation. This means that both load shedding and load shifting can be used by the co-optimization model whenever it considers valuable for minimizing the total system costs. However, a set of restrictions are included for the technical DR assessment limiting the maximum share of flexible demand that may be shed or shifted for each sector and year. The assessment of the economic potential for DR is conducted by including two parameters, which are responsible for computing the variable costs (US$/MWh) of shedding and shifting the load, respectively, such as proposed by Ref. [32].

The economic assumptions for load shedding (which are focused on the industrial sector[7]) have been based on the concept of the so-called opportunity cost (spot price of each region). This variable cost is established based on the Brazilian short-term electricity price (in Portuguese, PLD[8] - Differences Settlement Price) of typical past years. Additional information about the country's historical spot prices can be found in Ref. [39]. A similar approach has been considered by the pilot DR program (demand bidding/buyback) implemented by the Brazilian Electricity Regulatory Agency (in Portuguese, ANEEL) for large industrial consumers. For this pilot program, the spot price (i.e., PLD) is used as the reference baseline for the consumers' financial rewards due to short-term interruptions to their supply [40].

However, given the high variability[9] of the spot market prices, the assessment of the economic DR potential requires the definition of three scenarios. The first scenario (DR^N) considers the average spot price for each region and season in a typical year (i.e., a year in which no extreme weather conditions were perceived in the country). The DR^- and $DR^þ$ scenarios take into account the spot prices for a typical drought (2014) and wet (2011) year, respectively, which were chosen based on real data retrieved from the national grid operator [25]. These assumptions are taken into account to better address the impact of different weather conditions and determine the extent to which the spot prices might have over both the overall installed capacity and the level of CO_2 emissions for each year and region.

For load shifting, the costs to implement DR are included in the model as a penalty per each hour shifted (US$/MWh). This parameter can assume a different value for each model region, although we consider the same value for all subsystems. The maximum delay and advance in which the load of each sector may be shifted are also considered for both assessments, i.e., for the technical and economic DR potential evaluation. Table A.1 (Supplementary Material) summarizes the main technical and financial assumptions considered for each scenario, including the estimated average short-term prices (in US$/MWh) for each Brazilian subsystem and season [41].

3. Results and discussion

This section evaluates the proposed model using the Brazilian power system as the case-study. The base year of the model is 2018 and the technologies considered are summarized in Fig. 1. Distributed Solar Photovoltaic (PV) is included within the co-optimization model as an exogenous technology based on government forecasts for the entire planning period (see Refs. [42,43]). These projections have been established for 2027 [43] and 2040 [42]. Therefore, linear extrapolation is considered for the intermediate years of the planning period for distributed solar PV. Conventional power generation technologies comprise natural gas, coal, fuel oil and nuclear power plants. The variability of intermittent renewable technologies such as wind and solar PV are represented considering different capacity factors for each time slice.

This research also includes the country's geographical heterogeneity to achieve more reliable results splitting the country into four main subsystems, namely North (NO), Northeast (NE), South (SO) and Southeast (SE). The existing interconnection capacities (i.e., transmission lines) between Brazilian subsystems (i.e., NE, NO, SE and SO) are considered based on the minimum and maximum electricity exchange between subsystems. The South international connection is also considered a possible technology, since it is the most critical border trade between Brazil and neighborhood countries. The model's parameters can also be included distinctly for each subsystem, such as the annual demand growth (see Table A.3), transmission capacities and prices of not meeting the load, for instance.

The already centralized contracted capacity for the medium-term (2018e2023) is also included as a residual capacity[10] based on the medium expansion plan of the country (in Portuguese, PDE [43]). Power generation technologies are represented considering their available, minimum and maximum installable capacity, capacity factor, costs (i.e., investment, fixed and variable costs) and efficiency. The minimum and maximum installed capacity set, respectively, the lower and the upper limits for the capacity in the optimization procedure. The upper threshold values are not included for all power options, i.e., they are restricted only for selected technologies based on technical and economic relevant aspects. The most relevant technical and economic input data considered in the modeling approach are presented in Table A.2 (Supplementary Material) representing the CAPEX (US$/kW) [44e46], variable costs (US$/GJ) [44,45], fixed costs (US$/kW) [44,45], fuel costs (US$/GJ) [45], technologies efficiency (%) [44,46], capacity factors [25,44,46] and the projected lifetime for each power source (years) [44]. Other relevant data is illustrated in Table A.3 [44e50].

3.1. Model validation and reference scenario (without DR)

This section attempts to validate the model considering 2018 as the reference year. Also, the Business as Usual (BAU) scenario (without DR) is established to further compare the results with scenarios that include DR strategies. Scenario BAU considers that no DR strategies will be implemented during the forecast planning period (2018e2040). The results are concentrated on the following variables: overall system costs, CO_2 emissions and the total installed system capacity. Fig. 5 illustrates the comparison between simulated results and real data extracted from ONS [49] for the overall electricity production in 2018. Analysing Fig. 5, we can infer the similarity between real data with the simulated results for the reference year.

The total installed capacity for each year (2018e2040) of the planning period for scenario BAU is shown in Fig. 6. The overall new installed capacity reaches a value slightly higher than 212 GW in 2040 (scenario BAU). According to the simulation results, nuclear power plants are also expected to play an essential role in

[7] Load shedding is considered to be meaningful, especially for the industrial sector. This strategy could also be explored for other sectors, such as the residential and commercial ones. However, to not influence the user's comfort, our modeling approach only considers the load shedding strategy for large industrial consumers.

[8] The spot price (PLD) in the Brazilian electricity market is determined based on the marginal operating systems costs (in Portuguese, CMO).

[9] The high variability for the spot prices occurs across years and seasons in the country and this behavior is typical for systems that deeply rely on renewable energy, such as the case of Brazil (mostly dependent on hydropower).

[10] The only exception is for the distributed solar PV.

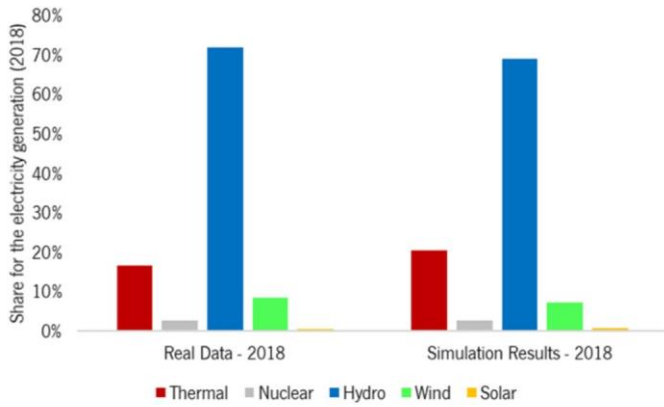


Fig. 5. Comparison between simulated results and real data extracted from ONS for the electricity generation in 2018.

expanding the future system capacity reaching about 13.5 GW in 2040. Wind and solar power are also considered in the country's expansion plan leading the way towards a sustainable future. It is essential to highlight that the distributed solar PV was exogenously included in the model over the entire planning period based on the current government projections [42,43].

The future expansion for thermal power plants seems to be mostly based on natural gas power stations, projected to increase from 12.5 GW to 60.8 GW between 2018 and 2040. This finding broadly supports the ones reported by the Brazilian Energy Research Office (EPE), highlighting that natural gas will have a significant role throughout the decades as electricity demand grows in the country. The future high reliance on natural gas may be explained by numerous factors, including (i) the high reserves from the so-called "*Pré-sal*" layer [50]; (ii) the low capital costs for implementing this technology; (iii) the short leading times for constructing new power plants and last, but not least, (iv) because this power source is considered the cleanest burning and the least polluting fuel among fossil fuel power plants [51].

3.2. Scenarios with DR

This section moves on to quantitatively evaluate the most significant long-term impacts of implementing DR measures for the power system assessed in this research, with a particular focus on answering how cost-optimal pathways would change with the inclusion of DR measures within the co-optimization model. Fig. 7 illustrates the new installed capacity between 2018 and 2040 for scenario BAU and scenarios with DR (DR^{T}, DR^{N}, DR^{-} and DR^{b}).

For scenario DR^{T}, a decrease of about 13.3% (compared to scenario BAU) is projected in the overall new installed capacity during all the planning period, reaching 184.1 GW in case the entire estimated technical potential for DR would be exploited. However, when we analyze the scenarios that include economic restrictions for implementing DR, the potential to reduce the new installed capacity is smaller compared to scenario DR^{T}. For scenario DR^{N}, the overall new installed capacity reduces only by 7.2% compared to scenario BAU - from 212.3 GW to 196.9 GW. It is worth noting the high decrease in the overall natural gas capacity for all DR scenarios compared to scenario BAU. Comparing, for instance, the new natural gas installed capacity for scenario BAU (41.7 GW) and scenario DR^{T} (23.1 GW), it can be seen a decrease of almost 45% between scenarios. Although the difference is smaller for the new natural gas installed capacity between scenario DR^{N} and scenario DR^{b}, it is still significant. Small hydro projects and wind power are also affected for scenarios with DR implementation and, to a lesser extent, the expansion of the biomass power source.

When the variable costs for implementing DR (load shedding) are considered higher (scenario DR^{b}), compared to scenario BAU, DR could cost-effectively add up to only 2.2 GW of avoided installed capacity in the power system. This finding might suggest a restricted potential in reducing the need for additional power system capacity if the PLD prices tend to increase, as represented in scenario DR^{b}. Given the high reliance on hydropower resources and its importance for the integration of RES [52] coupled with the vulnerability to climate change, the assumed prices represent an important source of uncertainty for the model.

Simulation results for each scenario regarding the new installed capacity (2018e2040) and its share in the total electricity production (2040) for each power source are presented in Table A.4 (Supplementary Material). Turning now to analyze the average regional potential for load shedding (Fig. 8) for the entire planning period (2018e2040), our results may support the hypothesis that

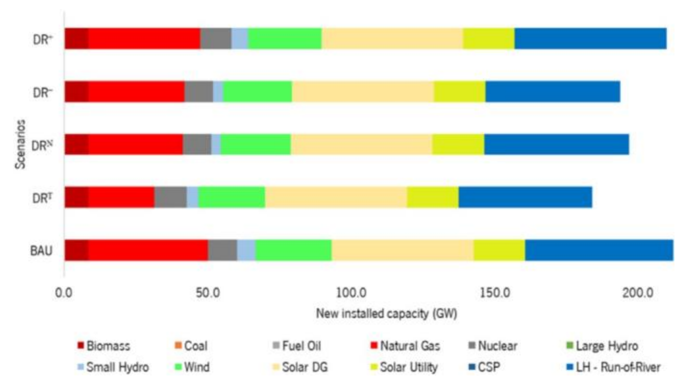


Fig. 7. New installed capacity between 2018 and 2040 for each scenario.

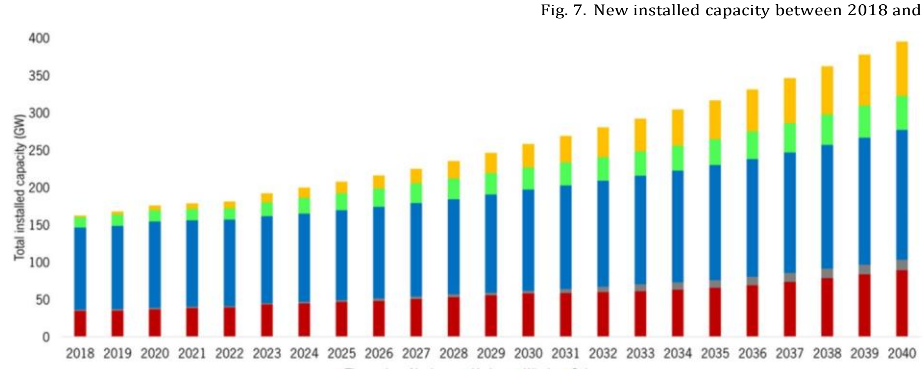


Fig. 6. Total installed capacity by source for scenario BAU (2018e2040).

the highest load flexibility potential seems to lie in the Southwest (SE). The differences in the regional potentials for load shedding can be explained by the considerable heterogeneity of industrial processes among regions. As expected, a significantly higher DR potential can be noted for the Southwest (SE), since this region is forecasted to have the highest theoretical load flexibility potential as assessed by previous research (see Ref. [27] for details). Also, the findings reported in Fig. 8 suggest that the differences for the average load shedding potential between scenarios DR^T and DR^N are rather significant for all regions varying from 45% (NO), 59% (SE), 63% (SO) to 65% in the Northeast (NE).

The percentage share for each cost category is illustrated in Fig. 9 for all scenarios. These costs are disaggregated by the ones incurred for expanding the power system during the planning period (investment, operating and fuel costs - Fig. 9a) and the ones related to the avoided CO_2 emissions, imported electricity and variable DR costs (Fig. 9b) for each scenario.

It can be seen from the data in Fig. 9 the different contribution shares for each cost category. The investment, operating and fuel costs have the highest percentage contribution. Fig. 9 illustrates that the investment costs represent the highest contribution share for all scenarios. Also, it is worth mentioning that for scenarios with DR implementation, the percentage share for the investment costs is smaller compared to scenario BAU. However, this comes with an increase in the ‘Demand Response’ cost category (Fig. 9b). On the other hand, for all scenarios with DR implementation, even considering the costs incurred to DR implementation, the overall system costs are smaller compared to scenario BAU, such as illustrated in Fig. 7. No significant differences among scenarios were found for the cost participation share of CO_2 emissions (see Fig. 9b). The cost contribution share related to the imported electricity is found not to vary significantly among scenarios with DR. Further analysis of the data reveals the impact of considering different prices for load shedding. The most striking result to emerge from the data analysis is that for prices of a typical drought year ($DR^\flat$), the contribution share of DR costs represents only 0.1% from the overall system costs, whereas, for scenario DR^N, this share increases to a value near 2.1%. Therefore, the sensitivity analysis carried out over the DR costs (through the simulation of different scenarios with DR) illustrates how weather conditions might affect load shedding if considering the spot price as the basis for the industrial consumers' financial rewards.

Fig. 10 shows the exploited and non-exploited potential for load shedding for each scenario with DR (average value in TWh between 2018 and 2040). Compared to the available theoretical DR potential

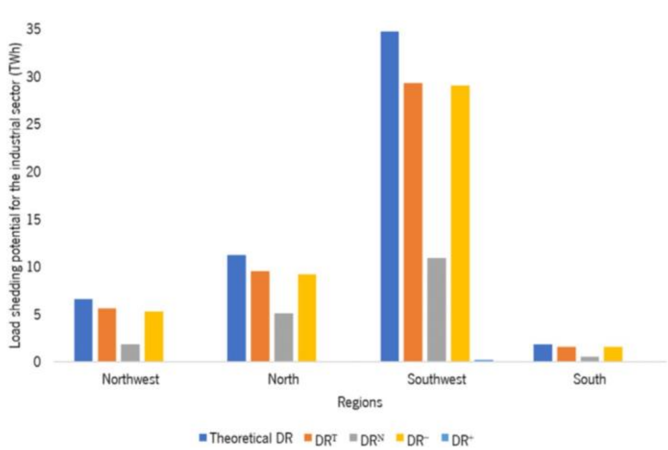


Fig. 8. Average regional potential for load shedding for the industrial sector between 2018 and 2040.

(see Ref. [27]), the average technical DR potential exploited is slightly higher than 84% (scenario DR^T). For scenario DR^N, on average, more than 33% of the theoretical load flexibility potential seems to be used between 2018 and 2040. A significant difference has been found between scenario DR^- and scenario $DR^\flat$ (i.e., when different prices are considered for load shedding) since the exploited DR potential strongly varies between scenarios. For prices of typical drought years (scenario $DR^\flat$), the simulation results indicate an exploited share of about only 0.4%, whereas, for a wet year (scenario DR^-), this value considerably increases to almost 83%. This indicates the high impact of electricity prices over the potential for load shedding in the country. Therefore, based on our premises related to the costs attributed to load shedding (which derived from average weather conditions, i.e., dry and wet years which conditioned the spot prices), we can infer that the uncertainties related to weather conditions across future years are considered a vital issue to be addressed in future assessments of the economic DR potential. Further research could be undertaken to investigate these effects more precisely using stochastic models, for example.

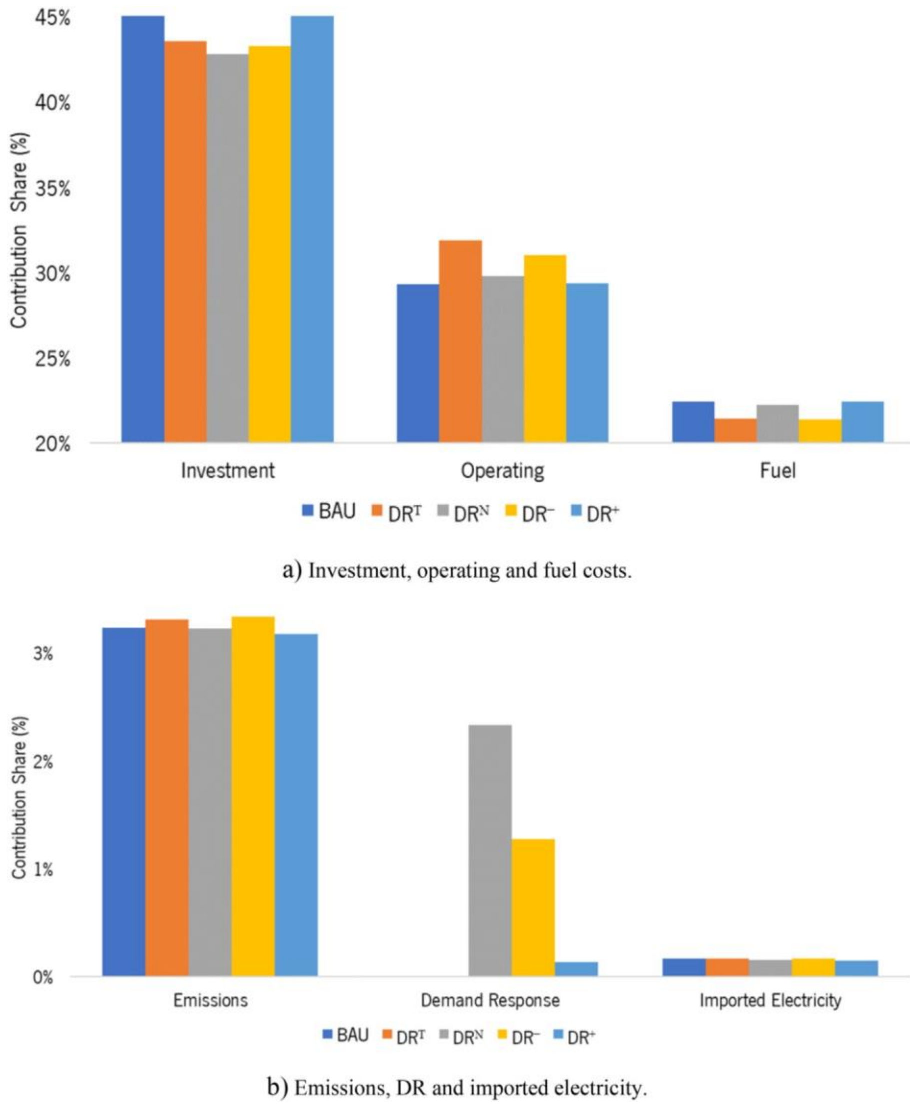
4. Discussion of the findings

The power system evaluated in this research deeply relies on hydropower energy. The Brazilian government's strategic plan still considers hydro resources an essential element for the future expansion of the power system [50]. However, the remaining hydro potential is almost entirely concentrated in the North region and its exploitation raises a set of environmental and social challenges [50]. Although considered a dispatchable power source, reservoirs' regularization capacity has been decreasing over time in the country [53]. This fact, coupled with the high increase of VRE from wind and solar power systems, suggests an increasing need to use new load balancing options such as DR strategies, which also justifies the present study's importance.

The considered price of shifted demand was based on Ref. [32]. However, after performing a set of simulations, it was realized that the economic DR potential for the power system evaluated in this paper is not affected even considering a high range for the price of shifted demand (e.g., 0.1 US$/MWh to 10 US$/MWh). These findings are also in agreement with Ref. [54], which addressed (partly) the DR potential for the case of Brazil and highlighted the limited DR contribution for balancing purposes. Our results also support this conclusion since even when no costs are considered for load shifting (i.e., Price of Shifted Demand¼ 0 US$/MWh), the total system costs are reduced only by less than 0.3% compared to the scenario which considers the price of shifting demand with a value of about 10 US$/MWh. Hence, it could conceivably be hypothesized that for systems with a high hydropower share, the load shifting potential is somehow limited for load balancing purposes. Therefore, these findings provide empirical evidence that the load shifting flexibility potential exists, but it is very limited for the Brazilian power system and its effect on the total system costs seems to be very small.

The following paragraphs attempt to address the DR-related benefits for the power system evaluated in this research. Our efforts are focused on answering the potential of flexible loads to (i) delay future investments in expanding the supply-side; (ii) RES integration; (iii) reduced need for thermal capacity; (iv) decrease in the level of CO_2 emissions and (v) the possibility of enhancing the synergies between power subsystems within the country.

i. Delay in investments: The results revealed a delay in the investments for new power generation capacities, decreasing 33% (on average) between 2020 and 2030 for scenario DR^T



a) Investment, operating and fuel costs.

b) Emissions, DR and imported electricity.

Fig. 9. Contribution shares for each cost category.

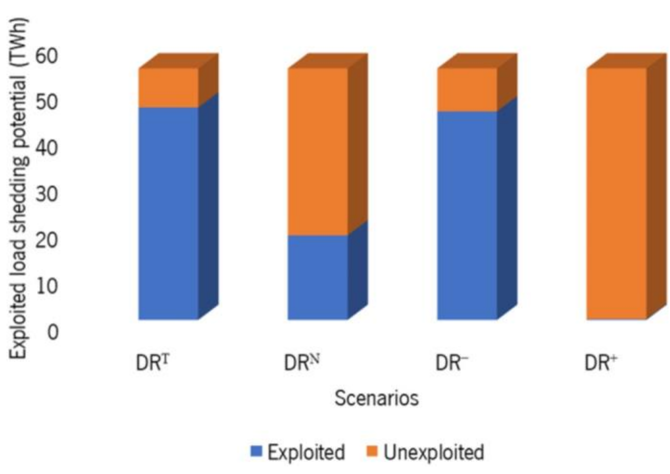


Fig. 10. Exploited and non-exploited load shedding potential compared to the theoretical load flexibility potential.

compared to scenario BAU. The delay in the investments for new power capacities have also been observed when the variable costs to implement DR are included. For these scenarios, however, the reduction varies from 3% (DR^{b}), 14% (DR^{N}) to 19% (DR^{-}) compared to scenario BAU between 2020 and 2030. Although the potential to delay investments for the last ten years of the planning period (2030e2040) still exists, it seems much lower than those from the ten first years (2020e2030).

ii. Integration of RES: A limited potential of DR to integrate additional renewable plants was found since only small changes were verified in the overall installed capacity from VRE sources between scenario BAU and scenarios with DR. There are two likely causes for this limited contribution: (1) the power system evaluated in this paper already relies mostly on RES (primarily from hydropower) and (2) because of its high reliance on hydropower coupled with the decreasing regularization capacity of reservoirs, the maintenance of the high share of renewable energy is considered a challenge. These results provide further support for the hypothesis that for systems with a high share of RES from hydropower, the DR contribution is somewhat limited in integrating larger shares of renewables from VRE sources.

ii. Reduced need for thermal capacity: We also verified a great potential of DR for reducing the need for additional thermal capacity, especially for the natural gas power source, which decreased by 45% (DR^T), 21% (DR^N), 19% (DR^-), and 7% ($DR^þ$) compared to scenario BAU. Only small changes were verified among nuclear and biomass power plants among scenarios regarding the new future power system capacity.

iv. Decrease in the level of CO_2 emissions: The overall level of CO_2 emissions is also affected by the DR implementation and decrease for all scenarios compared to scenario BAU. This result may be mostly explained because of the reduced need for using natural gas for producing electricity in the scenarios with DR implementation. The level of emissions decreased by almost 9.8% and 3.4%, respectively, for scenario DR^T and scenario DR^N compared to scenario BAU. However, no significant differences were found in the overall level of emissions between DR^N and DR^- scenarios (650.7 million tons for scenario DR^N and 641.2 million tons for scenario DR^-), notwithstanding their significant difference in the overall system costs. This outcome can be mostly explained by the fact that the overall installed capacity of thermal sources (mainly from natural gas) has not been significantly affected by the optimization process between scenario DR^N (32.9 GW) and scenario DR^- (33.7 GW) and thus its share on the average electricity production was not deeply affected. Taken together, these results suggest that the reductions in the costs for load shedding (for scenario DR^-) are not sufficient to significantly reduce the electricity production from thermal sources. Thus, the overall CO_2 emissions from scenario DR^- are not meaningfully affected compared to scenario DR^N.

v. Possibility of enhancing the synergies between power subsystems: DR may also provide additional benefits from the long-term power planning perspective. Findings of this research revealed the potential of DR to decrease by nearly 15% the need for additional transmission capacity for scenario DR^N compared to scenario BAU. However, the most striking result that emerged from the data analysis is that a slight increase (8%) in the new transmission capacity was observed for scenario $DR^þ$ compared to scenario BAU. According to the simulation results, this increase might be mostly associated with expanding the international connection with the South region. This finding may be partly explained by the high spot price (i.e., PLD) for the South (SO) region (with an average value of 178 US$/MWh across seasons for scenario $DR^þ$). These results may further support how different load shedding prices may change optimal DR scenarios and how other regional characteristics might potentially affect the country's economic load flexibility capacity.

5. Conclusion

The modeling approach proposed in this research resulted in an enhanced co-optimization model for long-term decision-making, recognizing the impact of short-term variability of both demand and RES supply and well-suited systems with a high share of RES and under different demand flexibility conditions. Although the results should be interpreted with caution, this study has several strengths and contributions to the current literature, which comprises a detailed analysis of the Brazilian power system, with (i) the inclusion of power grid interconnections between subsystems and with neighbors countries; (ii) DG from PV systems have been exogenously added up to the model (iii) a sectoral analysis (i.e., for the industrial, residential, and commercial); is taken into account for the DR formulation; (iv) last, but not least, the present study also extends our knowledge by expanding the cost of opportunity concept for shedding large industrial consumers' load based on the historical spot market prices.

We concluded that the economic benefits brought about by the implementation of DR measures might be positive for the power system evaluated, decreasing the overall system costs from 0.5% ($DR^þ$), 2.1% (DR^N), 7.6% (DR^-) to 11.0% (DR^T) when compared to scenario BAU. These results seem to be consistent with other research. The authors of [55], for example, evaluated the economic potential of DR for the West-European power system and concluded that DR implementation might reduce the total system costs by 1.7e2.5% compared to no DR deployment, which can be compared to scenario DR^N (2.1%).

There was found a big difference between the need for installed capacity for scenario DR^T compared to scenario DR^N, which decreased from 196.9 GW to 184.1 GW. The large sensitivity of DR exploitation based on market prices can also be noted for the economic DR scenarios, which is strongly related to the differences in the market prices among seasons. This significant sensitivity comes exclusively from the load shedding exploitation from the industrial sector and it is not related to the load shifting potential, which was found to be not deeply affected even under a high range of shifted demand costs for all DR scenarios.

The CO_2 emissions are also affected by the DR implementation and decrease for all scenarios evaluated compared to scenario BAU, varying from 1.9% to 8.5% across scenarios. The impact on RES integration has also been assessed and the results revealed a limited potential of DR to integrate renewables mainly because of the current high reliance on hydropower. A great potential of DR to reduce the need for additional thermal capacity has also been verified primarily from the natural gas power source. The impact of DR on the need for additional transmission capacity has also been assessed and the results suggest that the spot prices might significantly affect the optimal scenarios with DR.

We believe that policy-makers should have a more active role to implementing effective demand-side investments. The new policies may have a great potential to change business models among Brazilian utilities. The policy implications of the analysis carried out in this research include that we have learned that integrating DR resources into the Brazilian electricity market requires a set of regulatory changes. These new regulatory changes may positively influence the potential benefits of DR usage for almost all stakeholders. This research may also increase the potential for policy-makers to develop effective public policies by determining, for instance, the selection of long-term sustainable energy plans but also future optimal DSM portfolios for the country. The findings reported here would also support the definition of cost-effective DSM portfolios for specific customer classes and technologies. Due to the country's size and heterogeneity characteristics, the DSM portfolio could be established differently for each region to meet particular stated policy goals such as envisaging environmental objectives and/or economic development targets.

Therefore, this study lays the groundwork for future research into the role of demand-response in power systems. Although the results may not be generalizable to a broader range of power systems, it is possible to hypothesize that these conditions are more likely to occur in power systems with similar characteristics to the one assessed in this research. The methodology and findings broadly extend beyond the case addressed as it may provide valuable lessons for other electricity systems. Hence, it could conceivably be hypothesized that the results of this research might provide important insights into the leading role of DR in power systems with high RES from hydropower, which is more focused on delivering power than energy. We also highlight that the insights gained from this study may be of assistance to both practitioners and policy-makers by also empowering the development of advanced DR control strategies.

6. Opportunities for future research

This study set out to investigate whether DR measures can technically and economically compete with traditional supply-side options, focusing on the Brazilian power system. The findings reported here rely on numerous assumptions and simplifications. The investment costs (e.g., related to smart equipment and grid infrastructure) for DR implementation are not computed mainly because there is currently little agreement on these values and the commercial viability of DR is a further step to be assessed. The investment costs to implement DR is complex to predict and would strongly vary within countries. Therefore, we point out the need to further evaluate the DR potential by considering these investment costs.

A further study focusing on other balancing technologies such as batteries and electric vehicles is also suggested and may change the technical and economic potential for DR in the power system evaluated. It is essential to highlight that the sectors' aggregation may affect the real estimation of each category of DR potential. The assessment efforts have been focused on the residential, industrial and commercial sectors, but it is limited because individual processes/appliances were grouped to assess the technical and economic DR scenarios. A further study focusing on splitting up the country into individual processes/appliances is suggested, which would enhance the model granularization by assessing the technical and economic load flexibility potential for each process/appliance. Future research could focus, for instance, on simulating the DR potential by disaggregating each sector (e.g., evaluating the contribution of air-conditioners in the overall DR potential for the residential sector). It has previously been observed by Ref. [27], for example, that the use of air-conditioning systems in the residential sector would strongly contribute to providing a high level of flexibility for the Brazilian power system, with a particular high contribution between 10 p.m. and 6 a.m.

This paper has also focused on the evaluation of specific categories of DR strategies. We call attention to the need to develop a full picture regarding the assessment of other DSM strategies. Therefore, further work is required to establish a holistic evaluation of DSM, including the joint use of energy efficiency measures with DR strategies. Future studies on the current topic are highly recommended by assessing users' acceptance issues, since social behavior should affect the practical load management potential. The flexibility of DR may be lower in reality and further studies with more focus on the estimation of the so-called achievable DR potential is therefore highly recommended.

This research may also contribute significantly to increase the potential for policy-makers to develop effective public policies by determining, for instance, the future optimal DR portfolio for the country. The geographical distribution of DR participants should be further addressed and this research may be of great assistance in this task. Notwithstanding these limitations, we highlight the contribution of this research, which could support the decision-making process in different systems with high shares of RES and under other demand flexibility conditions.

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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Credit author statement

Géremi Dranka: Conceptualization, Formal analysis, Methodology.: Data curation, Writing e original draft. Paula Ferreira: Formal analysis, Supervision, Visualization, Resources, Investigation, Writing e review & editing. Ismael F. Vaz: Supervision, Writing e review & editing.

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