IEEE Access
Multidisciplinary : Rapid Review : Open Access Journal

Received March 19, 2022, accepted April 11, 2022, date of publication April 22, 2022, date of current version April 29, 2022.

Digital Object Identifier 10.1109/ACCESS.2022.3169696

Demand-Shifting Strategies to Optimize the Performance of the Wholesale Electricity Market: A Dominican Republic Study Case

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ABSTRACT The dimensions of the costs and incentives necessary for integrating demand response into the wholesale electricity market are subject to energy policies and bulk system operation. The electricity industry must gain operational flexibility to support the energy transition caused by renewable energy and decarbonization. Complementary services and technologies of demand response programs can be optimized by exploiting the variety of uses of this resource. The main objective of this work is to apply the concept of elasticity of substitution in a strategic demand shift program to promote the integration of renewable energies and the reduction of non-served power, considering an economical and safe generation dispatch. The methodology is analyzed through a case study applied in the Dominican Republic's electricity market, in which the elasticity of substitution coefficients is used to adjust variations below 10.49% of the base demand in the peak period. These variations reduce the generation operating cost by 8.4%, marginal cost by 30.19%, and non-served power by 19.1% when renewable energy increases by 5%. The inclusion of the cost of CO_2 emissions in the simulation of the operating cost function makes the objective function higher than the baseline function. For relative variations in operating cost ranging from 7.27% to 16.03%, the reduction in tons of CO_2 equivalent varies from 2.77 to 28.02. This study contextualizes the economic effect of the CO_2 emissions control, giving new possibilities to optimize system operation and the wholesale electricity market based on demand response programs that encourage flexible consumption, with favorable economic and environmental results.

INDEX TERMS CO_2 emissions, demand response, the elasticity of substitution, renewable energy, wholesale electricity market.

NOMENCLATURE

Acronyms

DR	Demand response
DRP	Demand response program
DC	Direct current
CES	Coefficient of elasticity of substitution
CO_2	Carbon dioxide
NCRE	Non-conventional renewable energy
MRS	Marginal rate of substitution
MPFR	Margin of primary frequency regulation
MSFR	Secondary frequency regulation

The associate editor coordinating the review of this manuscript and approving it for publication was Zhouyang Ren.

Indices and Sets

p	Index of the hourly period during weekly schedule (p∈P)
vl_p	Index of valley period during weekly schedule (vl∈p)
sh_p	Index of shoulder period during weekly schedule sh∈p)
pk_p	Index of peak period during weekly schedule (pk∈p)
hr	Index of the hourly period during daily schedule (hr∈H)
vl_{hr}	Index of valley period during daily schedule (vl∈hr)

sh_{hr}	Index of shoulder period during daily schedule (sh∈hr)
pk_{hr}	Index of peak period during daily schedule (pk∈hr)
g	Index of generation units (g∈G)
b	Index of the bus in the transmission network (b∈B)
t_g	Index of fossil generation units (t∈g)
w_g	Index of wind generation units (w∈g)
h_g	Index of hydro generation units (h∈g)
day	Index of the weekdays (day∈Nday)
$pday_{day,p}$	Index of the hourly period during the daily schedule (pday∈day, pday∈p)
iter#	Index of iterations (iter#∈Niter)
ω	Index of scenarios with uncertainty ($\omega \in \Omega$)
$nx_{b,g,p}$	Location node of generation g during period p
$nn_{i,j,p}$	Location nodes connected by a transmission line in period p (i∈B, j∈B).
rTX	Index of Transmission line resistance (rTX∈CL)
xTX	Index of Transmission line reactance (xTX∈CL)
pTX	Index of transmission peak line power (pTX∈CL)
P	Set of all hourly periods during weekly schedule
H	Set of all hourly periods during daily schedule
G	Set of all generation units
B	Set of all buses in the transmission network
Nday	Set of all days of the week
Niter	Set of all iterations
Ω	Set of all scenarios with uncertainty.
CL	Set of all characteristics of transmission lines

Appendix
General specifications for model testing

I. INTRODUCTION

The design of energy policies to integrate new technologies must include economic, social, and environmental perspectives to ensure the future development of electrical systems and market performance. These policies require mechanisms or profitable instruments to adapt to technologies, business models, and traditional electrical operations. This adaptation implies integrating flexible resources to cope with variations in generation and demand owing to failures or disturbances caused by deviations during the dispatch of the operating schedule. [1]. Different alternatives have been presented in the literature to increase operational flexibility, including distributed generation (DG), demand response (DR), energy storage, smart grids, and regional integration [2]–[5].

According to [6], non-generation resources are viewed as non-conventional sources of energy used to diversify power market services, such as stability, flexibility, and reliability of the energy supply. DR and energy storage are non-generation techniques and programs developed to support intermittent renewable energy integration and efficiently manage the grid [7].

Intermittent variable generation contributes to the fulfillment of the goals assumed by the countries for climate change while simultaneously lowering energy prices. These characteristics are desirable for advancing the energy transition processes. However, they pose a significant challenge for island countries such as the Dominican Republic because of the high reserves needed to compensate for their variability and ensure stable and secure electrical operation. Therefore, it is necessary to combine resources to take advantage of the variable renewable generation. In this research, the provision of operational flexibility services based on demand response is applied to the Dominican electricity market.

In the literature, proposals for methodologies based on DR with different perspectives have been verified. Among these studies: In [8], a methodology based on demand management is formulated to minimize the daily cost of electricity and consumer dissatisfaction. The results show that cost savings are between 6% and 12% without modifying consumer habits. In addition, if consumers modify their consumption habits, it can reach 50%.

The study in [9] proposes a strategy model to maximize the social welfare of an aggregator. The methodology is based on on-demand flexibility and q-learning techniques, and the model determines that DR trading is more stable in the daily market based on the relationship between price and elasticity of demand, marginal cost, time, and profit constraints. Their results were verified by employing simulations of residential user consumption.

In [10], it was established that a contract-based approach guarantees consumers' rights and obligations. The contract provides an efficient framework for applying DR, obtaining results similar to real-time dynamic pricing. This scheme was proposed as a retail tariff design for price-responsive elastic demand in a smart grid. On the other hand, [11] provides DR resources through aggregators buying and selling in the wholesale market. This study analyzed a business model that combines aggregator participation, forecasting, bidding, and settlement processes. It also gathers information from similar models in order to understand their evolution and challenges. The work presented in [12] demonstrates that the demand from large consumers can create operating reserves, reduce the cost of energy supply, and influence the scheduling of intermittent renewable energy production. The results of this modelling allow the analysis of the behavior of the type of consumer, reserve limits, and effects of wind energy uncertainty. Another methodological approach to demand-side flexibility was presented in [13], indicating the competitive conditions necessary to mitigate the market power of generating agents when demand shifts strategically. This study analyzes a case study that demonstrates the benefits of reducing market power when the flexibility to shift demand in available locations increases when network congestion occurs. Finally, [14] implemented a methodology based on the interaction between the system operator and competing aggregators to provide DR services and maximize their revenues through rewards. The model corresponds to a non-cooperative game supported by the Nash equilibrium approach, in which the operator increases its profit by up to 7%.

The authors in [15] indicate that a marginal increase in the demand response implies growth in the penetration level of renewables. This study proves that demand response allows the replacement of thermal generators' high variable production costs with price-taking renewable generators.

The thesis correlating the increase in variable renewable energies with the reduction in prices in the wholesale electricity market was studied in [16], [17]. In [18], wholesale electricity markets in the United States were studied, highlighting the trend of an average reduction of $ 0.37 MWh when the penetration level of variable renewable energies increased by 1%.

This study highlights the opportunities presented by the electricity market in the Dominican Republic to gain operational flexibility during the operation of the electricity system, based on the possibilities of its regulation. The main contributions are as follows: (i) The partial displacement of demand from peak to off-peak periods, based on the elasticity of substitution, reduces the operating cost of supply, non-served power, and CO_2 emissions. (ii) Establish an incentive scheme to benefit the participants in the DR program. (iii) A dispatch simulation tool to evaluate sensitivities during the modelling process of the optimal complementarity of demand response programs with variable renewable energy participation.

This paper is structured as follows: Section II presents the problem statement to support the methodology; Section III explains the methodology that integrates an incentive-based demand response program in the wholesale electricity market of the Dominican Republic, reducing the cost of supply and CO_2 emissions, and defines the mathematical formulation based on four optimization models: the first corresponds to an economic dispatch problem, the next one considers the elasticity of substitution to shift demand from peak to off-peak periods, and continues with the distribution of the new hourly demand and the incentive scheme for DRP participants; in the last model, the baseline is updated with the inclusion of CO_2 emissions control; Section IV allows the measurements of the demand response program through reports and indicators, determines and discusses the results of the case study applied to an IEEE 14-bus power system; and finally, Section V offers conclusions related to contributions, limitations, and future work.

II. PROBLEM STATEMENT

The wholesale electricity market of the Dominican Republic resulted from the capitalization process of state companies in 2000. The main characteristics are free competition in generation and the economic principle of marginal costs. The transmission and distribution activities operate as natural monopolies, highlighting the particularity that the transmission activity is managed by a single company, which simultaneously plays the role of being the system operator. The distribution activity includes the role of commercialization and is organized according to the geographic areas of the concession.

According to regulatory guidelines [19], the wholesale electricity market involves the interaction of generation, transmission, distribution, commercialization companies and non-regulated users, selling, transporting, and buying electricity. This market is based on contract and spot markets. In the contract market, transactions for the purchase and sale of electricity are conducted based on freely agreed supply agreements between the parties. Economic transactions are conducted at a short-term marginal cost in the spot market.

In energy terms, the geographical isolation of the Dominican Republic translates into a barrier with essential economic consequences for its energy supply. Although the generation mix is concentrated in oil derivatives and coal, the country faces price volatility and availability because it is not a producer, and the investment portfolio does not direct a significant share of the generation mix towards renewable energy, which barely reaches 12%. The impossibility of establishing interconnections with Haiti, the only border country, closes development possibilities and takes advantage of economies of scale, leading to high reserve margins and dependence on expensive energy sources.

Fig. 1 is a tree of problems that summarizes the factors that affect the behavior of the Dominican Republic's electricity market, from the causal perspective that worries the population, expressed in poor quality of service and the disbursement of permanent subsidies for the electricity sector. These circumstances turn the Dominican Republic into a costly market for consumers and are not very profitable for production and the environment, motivating the exploration of alternatives derived from applying new and flexible mechanisms.

To achieve the 13th Climate Action Goal, the Dominican Republic must reduce greenhouse gas emissions by 25% by 2030, compared to 2010, and increase the participation of renewable energies by 25% by 2025, according to the United Nations Development Program (UNDP). From the perspective of the electricity sector, we propose including the participation of DRP in the wholesale electricity market as a complementary alternative.

III. METHODOLOGY AND FORMULATION MODEL

This study evaluates the methodology proposed in [20] to implement the application of DR based on the strategy of shifting demand from one hourly block to another in the daily load curve to minimize generation supply costs and reduce CO_2 emissions. The analysis considers the wholesale electricity market regulation of the Dominican Republic as a case study.

This study simulates an optimal direct current flow without ohmic losses for demonstration purposes. It analyzes the effects of operational constraints, considering the provision

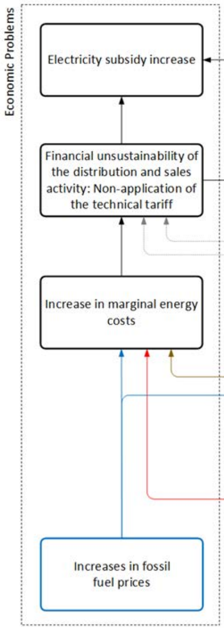

FIGURE 1. Problems tree in the wholesale electricity market of the Dominican Republic.

of DR to reduce non-served power, supply cost, and CO_2 emissions without altering the physical generation-demand balance, and providing the incentives required by the demand to guarantee the corresponding economic and environmental signals. Environmental attributes have not been well internalized in Dominican households and industries, motivating the need to structure an attractive incentive scheme based on experiences and related works, as verified in [21].

Fig. 2 summarizes the sequence of activities that constitute the methodology. It is based on the following criteria: agent prospecting on the availability of variable renewable energy, segmentation of consumption profiles based on the elasticity of substitution, incentive-based DRP, and determination of supply costs based on economic and environmental components.

The modeling process focuses on consumer participation using a DRP that combines the availability of variable renewable energy and the stratification of consumption profiles. The level of flexibility for the change in the load curve was adjusted using the constant elasticity of substitution (CES) function. Fig. 2 shows that the methodology relies on a sequential, iterative, and multi-objective process. Initially, supply costs are minimized in a generation-network model for a baseline that excludes DRP participation. Subsequently, demand shifts are determined using the CES function by considering the marginal cost obtained at the baseline. The change in demand motivates a change in dispatch, and incentives are calculated to consolidate the demand decision in the next step. This incentive is a bounded fraction of the marginal cost obtained in the baseline and must be selected to motivate consumer participation without falling into the minimum and maximum extremes of indifference and exaggeration. Finally, the supply costs were verified under new demand conditions.

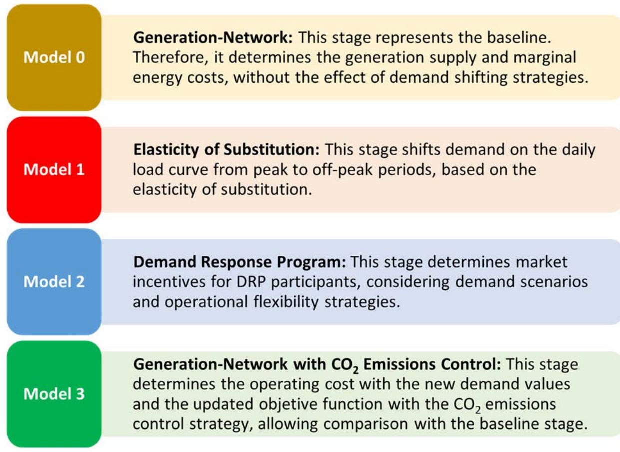

FIGURE 2. Methodology of flexible demand participation in the wholesale electric market of the Dominican Republic.

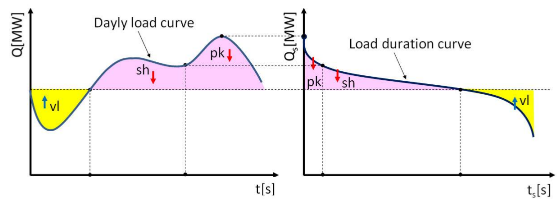

FIGURE 3. The physical effect of DRP in load curves.

The effects of including the cost of CO_2 emissions and their results were compared to those of the baseline.

The scope of the proposed model is expressed by a modular separation of the entire process, simplifying the optimization problem. This scheme facilitates the analysis of the results and identification or anticipation of possible difficulties.

For comparison purposes, Table 1 summarizes the contributions and critical concepts underlying the energy management model proposals of research that consider the common element of the constant elasticity of substitution, and other operating concepts, focusing on one of the following criteria: load-shifting profile, energy technology change, variable renewable energy, and CO_2 emissions.

The proposed methodology flattens the daily load curve and the load duration curve, as shown in Fig. 3. The annotations *Qs* and *ts* indicate that the demand and its period of occurrence are ordered from highest to lowest values in the load duration curve, whereas *vl*, *sh,* and *pk* identify the valley, shoulder, and peak zones in the consumption profiles of the load curves.

This adjustment results in a rescheduling of dispatch, allowing calling plants with lower variable production costs and establishing new fuel consumption conditions by technology type. The reduction of peaks, filling of valleys, and load curve flattening lead to a reduction in peak demand, prices, and congestion in the network infrastructure.

The optimization procedure decomposes the problem into stages and link models through recursive calculations. To meet this objective, mathematical programming in

TABLE 1. Summary of contributions and common key concepts of energy management proposals. Modified from [22].

Reference	Contributions	Recommendations	Highlighted concepts for comparative purposes				
			CES function	Load-shifting profile	Energy technology change	Variable renewable energy	CO_2 Emissions
[23]	Required investment in renewables and storage to decide on expanding the electric power system.	Incorporate operating and maintenance costs into the model.	x			x	
[24]	Analysis of consumers' response with different incomes and carbon allowance prices for the long and short term.	Include transactional costs in the model and the possibilities of participating in emissions market activities.	x				x
[25]	Develops methodology to determine the technological change from capital, labor, and energy.	Consider elements to mitigate environmental damage and inefficiencies in the resulting energy-intensive sectors.	x		x		
[26]	Management of industrial loads from a demand response program based on Real-Time Price to consider adaptability and adjustability criteria.	Due to the nature of the adjustments in the industrial load, it is necessary to evaluate the stability and quality effects on the electric power system.	x	x			
[27]	Describes the main aspects of econometric specification of the CES function for capital, labor, and energy inputs.	Conduct an applied case study based on the recommendations made.	x		x		
[28]	The substitution of the internal combustion engine vehicle by the electric vehicle, as an environmental alternative to the reduction of fossil energy, based on an incentive scheme, which additionally reveals the contribution of subsidies and technological progress to economic growth.	Extend the scope of the study to assess the direct impact from the end-user perspective.	x		x		x

models 0 and 3 minimizes an MIP function using the CPLEX solver, model 1 minimizes, and model 2 maximizes an NLP function using a CONOPT solver. The algorithm was developed in GAMS code and tested with the following computational resources: Intel(R) Core (TM) i7-10510U CPU @ 1.80GHz 2.30 GHz, RAM 16.0 GB.

Model 0 performs an economic dispatch that incorporates generation and network constraints. Model 0 represents the baseline for comparative purposes, against which the different decision variables are verified.

Model 1 was responsible for applying the load-shifting strategy as the first stage of the DRP. In this model, the theoretical principle that supports the demand displacement in the daily load curve obeys the elasticity of substitution for wholesale electricity market agents. The distribution of hourly demand is the functionality of model 2. The second part of the DR process defines an incentive scheme that allows the analysis of two different demand scenarios.

Finally, model 3 was coded from model 0, including the cost of CO_2 emissions and an approach to the conditions required for their reduction, according to the Intergovernmental Panel on Climate Change (IPCC) level 1 methodology. Economic and environmental indicators evaluate the behavior of the DRP and the incentives required to motivate the participation of the demand.

A. MODEL 0: BASELINE

The optimal values of the variables in model 0 are given by the minimization of objective function (1), subject to the generation and market constraints of the Dominican Republic. This model corresponds to an optimal DC power flow, adapted from the work conducted by [29], [30], and was tested on a modified IEEE 14 bus.

$$\begin{aligned} \min_{t\in g,h\in g,w\in g,b\in g,p\in g,}(\$) \quad & objMOD_0 = \sum_{t,p} \big(SUC_t \times y_{t,p} + SDC_t \\ & \times z_{t,p} + NFC_t \times u_{t,p} + VFC_t \times e_{t,p} \times d_p\big) \\ & + \sum_{w,p} C_w \times e_{w,p} \times d_p + \sum_{h,p} C_h \times \big(e_{h,p} - \eta_h \times epump_{h,p}\big) \\ & \times d_p + VOLL \times \sum_{b,p} nsp_{b,p} \times d_p \\ & \forall t, w, h, b, p \end{aligned} \tag{1}$$

Subject to:

$$\sum_t e_{t,p} + \sum_w e_{w,p} + \sum_h \left(e_{h,p} - \eta_h \times epump_{h,p}\right) - \sum_i flow_{i,j,p} + \sum_j flow_{j,i,p} + nsp_{b,p} = qBASE_{b,p}$$
$$\forall t \in nx_{b,t,p}, w \in nx_{b,w,p}, h \in nx_{b,h,p}, b, i \in nn_{i,j,p}, j \in nn_{i,j,p}, p \quad (2)$$

$$nsp_{b,p} \leq qBASE_{b,p} \quad \forall b, p \quad (3)$$

$$e_{t,p} \leq u_{t,p} \times AD_{t,p} \quad \forall t, p \quad (4)$$

$$\sum_p y_{t,p} \leq limSU_{t,day} \quad \forall t, p \in pday \quad (5.a)$$

$$\sum_p y_{h,p} \leq limSU_{h,day} \quad \forall h, p \in pday \quad (5.b)$$

$$r_{h,p} = r_{h,p-1} - \left(e_{h,p} - \eta_h \times epump_{h,p}\right) + NCR \quad \forall h, p \quad (6.a)$$

$$r_{h,p} = RINI \quad \forall h, p\,(1) \quad (6.b)$$

$$r_{h,p} = RFIN \quad \forall h, p\,(168) \quad (6.c)$$

$$e_{w,p} \leq WEF_{w,p} \quad \forall w, p \quad (7.a)$$

$$\sum_p e_{w,p} \geq \delta \times TLOAD \quad \forall w, p \quad (7.b)$$

$$MPFR_p^{TOT} = \psi \times \sum_b qBASE_{b,p} \quad \forall b, p \quad (8.a)$$

$$\sum_g \left(P_g^{MAX} \times u_{g,p} - e_{g,p}\right) \geq MPFR_p^{TOT} \quad \forall g, p \quad (8.b)$$

$$\sum_g \left(e_{g,p} - P_g^{MIN} \times u_{g,p}\right) \geq MPFR_p^{TOT} \quad \forall g, p \quad (8.c)$$

$$flow_{i,j,p} = SB \times \frac{\theta_{i,p} - \theta_{j,p}}{xTX_{i,j}} \quad \forall i, j, p \quad (9.a)$$

$$pTX_{i,j}^{MIN} \leq flow_{i,j,p} \leq pTX_{i,j}^{MAX} \quad \forall i, j, p \quad (9.b)$$

$$\theta_b^{MIN} \leq \theta_{b,p} \leq \theta_b^{MAX} \quad \forall b, p \quad (10)$$

$$e_{g,p} = P_g^{MIN} \times u_{g,p} + e_{g,p}^{\uparrow MIN} \quad \forall g, p \quad (11.a)$$

$$e_{g,p}^{\uparrow MIN} \leq \left(P_g^{MAX} - P_g^{MIN}\right) \times u_{g,p} \quad \forall g, p \quad (11.b)$$

$$e_{g,p}^{\uparrow MIN} - e_{g,p-1}^{\uparrow MIN} \leq R_g^{UP} \quad \forall g, p \quad (11.c)$$

$$e_{g,p-1}^{\uparrow MIN} - e_{g,p}^{\uparrow MIN} \leq R_g^{DOWN} \quad \forall g, p \quad (11.d)$$

$$u_{g,p} - u_{g,p-1} = y_{g,p} - z_{g,p} \quad \forall g, p \quad (12.a)$$

$$y_{g,p} + z_{g,p} \leq 1 \quad \forall g, p \quad (12.b)$$

$$P_g^{MIN} \leq e_{g,p} \leq P_g^{MAX} \quad \forall g, p \quad (13.a)$$

$$0 \leq epump_{h,p} \leq epump_h^{MAX} \quad \forall h, p \quad (13.b)$$

Constraint (2) refers to the energy balance. The equation considers the generation and demand of all consumers and also includes the power flows through the transmission lines and the non-served power.

The amount of non-served power represents a part of the demand not supplied by the system. Therefore, its value cannot exceed demand (3). The fossil generation availability declared for the operation schedule corresponds to the maximum value that the dispatch can handle (4). The stress experienced by a generation unit is influenced by the number of start-ups during the operating period with significant maintenance costs. These cycling constraints were considered for the thermoelectric and hydroelectric generation (5.a, 5.b).

The management of the hydroelectric reservoirs is described in (6.a, 6.b, 6.c). The wind energy penetration level is defined as the proportion of coverage of the total demand during the operation programming without exceeding the expected production in each period p (7.a, 7.b).

The spinning reserve provision considers the primary (MPFR) and secondary (MSFR) frequency regulation margins, as indicated in (8.a, 8.b, 8.c). The approximation of the power flow calculation on the transmission lines is given by (9.a, 9.b) and the phase angles that determine the flow conditions of the lines in (10).

The technical minimum power value determines the limits of the generator ramps and the available margin to increase or decrease (11.a, 11.b, 11.c, 11.d). The ON/OFF states of generator g and the conditions of continuity (coupling) in period p are given by (12.a, 12.b). The operating limits, minimum and maximum, which limit the generation and pumping dispatch, respectively, are given by (13.a, 13.b).

B. MODEL 1: ELASTICITY OF SUBSTITUTION

This model considers two factors differentiated in energy consumption based on quantity and price specifications obtained in each period or block of periods [31]. This differentiation of energy makes it possible to evaluate the possibility of substitution between hourly blocks using the constant elasticity of substitution (CES) function. Therefore, the strategy of shifting demand from peak and shoulder periods to off-peak periods in the daily consumption curve is addressed as a requirement for proceeding with the application of the DRP.

In DRP applications, some models utilize the concept of price elasticity to motivate the effect of linearizing the demand curve at a specific operating point instead of considering the entire demand, creating a discontinuity in the decision-making process [32]. Unlike demand response models based on price elasticity, a model based on constant elasticity of substitution is a continuous decision-making process that allows for more flexibility.

The utility of the CES function (added value or available budget) is defined by two consumption factors (e.g., total demand in the peak and valley periods, total demand in the shoulder and valley periods), as verified in (14).

$$U\left(Q_1, Q_2\right) = \gamma \cdot \left(\alpha \cdot Q_1^{-\rho} + (1-\alpha) \cdot Q_2^{-\rho}\right)^{-\frac{\vartheta}{\rho}} \quad (14)$$

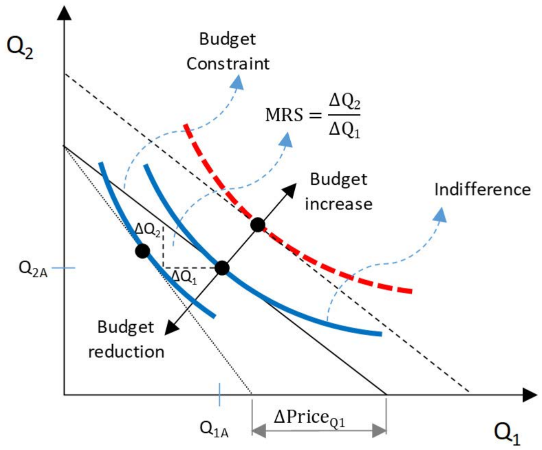

FIGURE 4. **CES function behavior.**

where, γ = Efficiency parameter; α = Intensity factor of good Q_1; $(1-\alpha)$ = Intensity factor of good Q_2; ϑ = Degree of scale; ρ = Substitution parameter.

The elasticity of substitution indicates the degree of sensitivity of the relationship between two production or utility function factors when the marginal rate (MRS) of its products or profits varies, as shown in Fig. 4. It measures the curvature of an isoquant or indifference curve and the possibility of substituting factors or goods [33].

Displacement was performed for each profile of the daily load curve. The method was considered in two iterations: the load was displaced from peak to valley in the first iteration. The second iteration is displaced from the shoulder to the valley. The load-shifting process looks for a flattening of the daily load curve, motivating a comparison to verify that the peak period's demand is greater than the shoulder period in the first iteration and the opposite in the second iteration. The validation of these comparisons activates the movements to the valley period; otherwise, load movement does not proceed.

The demand block (db) in the valley period includes hours 01 to 06, the shoulder period from 07 to 18, and 19 to 24 in the peak period. The determination of the hourly blocks is purely administrative, similar to that established in the wholesale electricity market of the Dominican Republic.

The available budget must support the new consumption conditions, so the scale adjustment is not modified (ϑ =1), motivating the following general expression (15).

$$
\begin{aligned}
&BVAL_{b,day}^{db_1 \leftarrow db_2} \\
&= \gamma_{b,day} \times \left[\alpha_{b,day} \times \left(q_{b,day,db_1,iter}\right)^{-\rho_{b,day}} + \left(1-\alpha_{b,day}\right)\right. \\
&\quad \left. \times \left(q_{b,day,db_2,iter}\right)^{-\rho_{b,day}}\right]^{-\frac{1}{\rho_{b,day}}} \\
&\qquad \forall b,\ day,\ iter\ (db_1 \leftarrow db_2) \qquad (15)
\end{aligned}
$$

To estimate the nonlinear function, it is necessary to apply linearization through the logarithmic form, as in the treatment in [34], as verified in this model's constraints (16.a, 16.b). Consequently, this model's objective function will focus on minimizing the residual error that results from this approximation process.

$$
\min_{b\in B, day \in N_{day}, iter1 \in N_{iter}} \quad objMOD_1^{ini} = \sum_b \sum_{day} \left(res_{b,day,iter1}\right)^2
$$
$$
\forall b,\ day,\ iter1 (vl \leftarrow pk) \qquad (16.a)
$$
$$
\min_{b\in B, day \in N_{day}, iter2 \in N_{iter}} \quad objMOD_1^{fin} = \sum_b \sum_{day} \left(res_{b,day,iter2}\right)^2
$$
$$
\forall b,\ day,\ iter2 (vl \leftarrow sh) \qquad (16.b)
$$

Subject to:

$$
\begin{aligned}
&ln\left(BVAL_{b,day}^{vl \leftarrow pk}\right) - ln\left(\gamma_{b,day}\right) \\
&+ \left[\frac{1}{\rho_{b,day}} \times ln\left\{\alpha_{b,day} \times \left(q_{b,day,vl,iter0}\right)^{-\rho_{b,day}}\right.\right. \\
&+ \left.\left.\left(1-\alpha_{b,day}\right) \times \left(q_{b,day,pk,iter0}\right)^{-\rho_{b,day}}\right\}\right] \\
&= res_{b,day,iter0} \\
&\forall b,\ day,\ iter_0 (vl \leftarrow pk) \qquad (17.a)
\end{aligned}
$$

$$
\begin{aligned}
&ln\left(BVAL_{b,day}^{vl \leftarrow sh}\right) - ln\left(\gamma_{b,day}\right) \\
&+ \left[\frac{1}{\rho_{b,day}} \times ln\left\{\alpha_{b,day} \times \left(q_{b,day,vl,iter1}\right)^{-\rho_{b,day}}\right.\right. \\
&+ \left.\left.\left(1-\alpha_{b,day}\right) \times \left(q_{b,day,sh,iter1}\right)^{-\rho_{b,day}}\right\}\right] \\
&= res_{b,day,iter1} \\
&\forall b,\ day,\ iter_1\ (vl \leftarrow sh) \qquad (17.b)
\end{aligned}
$$

$$
\begin{aligned}
&\sum\nolimits_{db} V_{b,day,db} = \sum_p \left(CMg_{b,day,p} \times qBASE_{b,day,p}\right) \\
&\forall b,\ day,\ p,\ iter1 : db\ (pk, vl), \\
&iter2 : db\ (sh, vl) \qquad (17.c)
\end{aligned}
$$

$$
\begin{aligned}
&q_{b,day,db,iter}^{MIN} \leq q_{b,day,db,iter} \\
&\leq q_{b,day,db,iter}^{MAX} \quad \forall b,\ day,\ db,\ iter \qquad (18)
\end{aligned}
$$

$$
\begin{aligned}
&BVAL_{b,day}^{vl \leftarrow pk} = \sum\nolimits_{db} V_{b,day,db} \\
&\forall b,\ day,\ db\ (vl, pk) \qquad (19.a) \\
&BVAL_{b,day}^{vl \leftarrow sh} = \sum\nolimits_{db} V_{b,day,db} \\
&\forall b,\ day,\ db\ (vl, sh) \qquad (19.b)
\end{aligned}
$$

$$
\begin{aligned}
&\sum_{db} qDR_{b,day,db} - \sum_{hr=1}^{6} qBASE_{b,day,hr} \\
&- \sum_{hr=19}^{24} qBASE_{b,day,hr} = 0 \\
&\forall b,\ day,\ db\ (vl, pk),\ hr(1-6, 19-24) \qquad (20.a)
\end{aligned}
$$

$$
\begin{aligned}
&\sum_{db} qDR_{b,day,db} - \sum_{hr=1}^{6} qBASE_{b,day,hr} \\
&- \sum_{hr=7}^{18} qBASE_{b,day,hr} = 0 \\
&\forall b,\ day,\ db\ (vl, sh),\ hr(1-6, 7-18) \qquad (20.b)
\end{aligned}
$$

The constraints in Eqs. (17.a) and (17.b) shift a fraction of the demand, determined from the elasticity of the substitution parameter, from peak to valley and shoulder to valley time blocks, according to the typified demand shift configuration. The cost assumed as the budget results from valuing the demand at the marginal cost obtained in the Model 0 reference, as verified in (17.c). This criterion for determining the budget is conservative. The combined effect of the increase in renewables and load shifting from peak periods motivates a reduction effect on the marginal energy costs, leading to possible surpluses to cover the billing amount.

The limits in the demand blocks contribute to the flattening effect of the load curve, supporting the adjustment of hourly distribution (18). The costs associated with the partial shifting of demand blocks do not involve additional expenses to the amounts initially considered in the budget because the CES function is not scaled (19.a, 19.b). To ensure that the demand blocks conform to the criteria of elasticity of substitution of the CES function and the demand response program strategy, the model proceeds to the equality specification that adds the demand blocks before and after the shifting load (20.a, 20.b).

C. MODEL 2: DEMAND RESPONSE PROGRAM

The demand response is characterized by a load displacement subject to the limit and ramp management criteria. The load profile on each bus was verified in advance to determine whether to shift. Therefore, it is necessary to establish a measure of the substitution parameter that serves as an incentive to motivate user decisions, as explained in [7]. The benefit to consumers participating in the demand response program is calculated from the marginal cost proportion obtained in the baseline generation dispatch. Additionally, the probability of occurrence was provided to study the methodology in terms of uncertainty [35]. The objective function defines the incentive scheme (21).

$$\begin{aligned} \max_{\omega\in\Omega,b\in B,day\in N_{day},hr\in H}(\$) \quad & objMOD_2 \\ &= \sum_{\omega}^{\Omega} \pi_\omega \times \left[\sum_{b}^{B} \sum_{day}^{Nday} \left(\sum_{hr=7}^{24} \{\lambda INC_{b,day,\omega,hr} \right.\right. \\ &\times \left(qBASE_{b,day,\omega,hr} - qDR_{b,day,\omega,hr}\right)\} \\ &+ \sum_{hr=1}^{06} \{\lambda INC_{b,day,\omega,hr} \\ &\left.\left. \times \left(qBASE_{b,day,\omega,hr} - qDR_{b,day,\omega,hr}\right)\}\right)\right] \\ &\forall b, day, \omega, hr \end{aligned} \tag{21}$$

Subject to:

$$\sum\nolimits_{\omega} \pi_\omega = 1 \;\; \forall\omega \tag{22.a}$$

$$\pi_\omega > 0 \;\; \forall\omega \tag{22.b}$$

$$\begin{aligned} &qBASE_{b,day,\omega,hr} \le qDR_{b,day,\omega,hr} \le qREF_{b,\omega}^{MAX} \\ &\forall b, day, \omega, hr \le 6 \end{aligned} \tag{23.a}$$

$$\begin{aligned} &qREF_{b,\omega}^{MIN} \le qDR_{b,day,\omega,hr} \le qBASE_{b,day,\omega,hr} \\ &\forall b, day, \omega, hr > 6 \end{aligned} \tag{23.b}$$

$$\begin{aligned} &if\, PC_{b,day,\omega,hr} = 0,\, then \lambda INC_{b,day,\omega,hr} \\ &= 0,\, else \lambda INC_{b,day,\omega,hr} \\ &\le \zeta_\omega \times \lambda BASE_{b,day,\omega,hr} \\ &\forall b, day, \omega, hr \end{aligned} \tag{24.a}$$

$$\lambda INC_{b,day,\omega,hr} \ge 0 \;\; \forall b, day, \omega, hr \tag{24.b}$$

$$\begin{aligned} &\sum_{hr=1}^{6} qDR_{b,day,\omega,hr} = q_{b,day,vl,iter_2} \\ &\forall b, day, \omega, hr\,(1to6)\,, db\,(vl)\,, iter_2 \end{aligned} \tag{25.a}$$

$$\begin{aligned} &\sum_{hr=7}^{18} qDR_{b,day,\omega,hr} = q_{b,day,sh,iter_2} \\ &\forall, day, \omega, hr\,(7to18)\,, db\,(sh)\,, iter_2 \end{aligned} \tag{25.b}$$

$$\begin{aligned} &\sum_{hr=19}^{24} qDR_{b,day,\omega,hr} = q_{b,day,pk,iter_2} \\ &\forall, day, \omega, hr\,(19-24)\,, db\,(pk)\,, iter_2 \end{aligned} \tag{25.c}$$

$$\begin{aligned} &qDR_{b,day,\omega,hr} - qDR_{b,day,\omega,hr-1} \le Q_b^{up} \\ &\forall b, day, \omega, hr \end{aligned} \tag{26.a}$$

$$\begin{aligned} &qDR_{b,day,\omega,hr-1} - qDR_{b,day,\omega,hr} \le Q_b^{down} \\ &\forall b, day, \omega, hr \end{aligned} \tag{26.b}$$

The constraints in Eqs. (22.a), and (22.b) incorporated stochastic treatment to define the two demand scenarios. In (23.a) and (23.b), the hourly demand limits are defined based on the baseline demand and the minimum and maximum allowed in the modeling. The constraints in Eqs. (24.a) and (24.b) show that the incentive value is established as a proportion of the baseline marginal cost of DRP participation. In (25.a), (25.b), and (25.c), the new hourly demand is distributed, considering the growth and reduction rates, as ramps bounded in (26.a) and (26.b).

D. MODEL 3: GENERATION-NETWORK WITH CO_2 EMISSIONS CONTROL

This stage has a comparative purpose with the baseline. In addition to the components used in Model 0, this stage included restrictions to reduce CO_2 emissions. Therefore, the objective function is modified as shown in (27).

$$\begin{aligned} \min_{t\in g,h\in g,w\in g,b\in B,p\in P,}(\$) \quad & objMOD_3 \\ &= \sum_{t,p} \left(SUC_t \times y_{t,p} + SDC_t \times z_{t,p} + NFC_t \times u_{t,p}\right. \\ &\left. + VFC_t \times e_{t,p} \times d_p\right) + \sum_{w,p} C_w \times e_{w,p} \times d_p \\ &+ \sum_{h,p} C_h \times \left(e_{h,p} - \eta_h \times epump_{h,p}\right) \times d_p + VOLL \\ &\times \sum_{b,p} nsp_{b,p} \times d_p + \mu_p \times \sum_{t,p} ee_{t,p}^{co_2} \\ &\forall t, w, h, b, p \end{aligned} \tag{27}$$

Subject to:

$$EF_{network}^{CO_2} = \frac{\sum_t \left(\sum_{gei} \beta \times EF_{t,gei}^{CO_2} \times \sum_p \left(\sigma_t \times e_{t,p}\right) \times d_p\right)}{\sum_t \left(\sum_p \left(\sigma_t \times e_{t,p}\right) \times d_p\right)} \quad \forall t, gei, p \tag{28.a}$$

$$CO_2eq = \sum_t \sum_{gei} EF_{t,gei}^{CO_2} \times GWP_{100} \quad \forall t, gei \tag{28.b}$$

$$ee_{t,p} = \frac{\left(\sum_{gei} \beta \times EF_{t,gei}^{CO_2} \times GWP_{100}\right) \times \sigma_g \times e_{t,p} \times d_p}{1000} \rightarrow \sum_p ee_{t,p} \leq ET_t \quad \forall t, gei, p \tag{28.c}$$

$$eeBASE_{t,p} = \frac{\left(\sum_{gei} \beta \times EF_{t,gei}^{CO_2} \times GWP_{100}\right) \times \sigma_g \times eBASE_{t,p} \times d_p}{1000} \rightarrow \sum_p eeBASE_{t,p} \leq ET_t \quad \forall t, gei, p \tag{28.d}$$

$$\Delta EE_t = \frac{\sum_p (ee_{t,p} - eeBASE_{t,p})}{\sum_p eeBASE_{t,p}} \times 100 \quad \forall t, p \tag{28.e}$$

$$eeA_w = EF_w^{OM} \times \sum_w \sum_p \left(\sigma_w \times e_{w,p}\right) \times d_p \quad \forall w, p \tag{28.f}$$

$$eeABASE_w = EF_w^{OM} \times \sum_w \sum_p \left(\sigma_w \times eBASE_{w,p}\right) \times d_p \quad \forall w, p \tag{28.g}$$

$$\Delta EEA_w = \frac{\sum_p \left(ee_{w,p} - eeBASE_{w,p}\right)}{\sum_p eeBASE_{w,p}} \times 100 \quad \forall w, p \tag{28.h}$$

The parameters relating to the GEI emission factor by type of fuel and the determination of CO_2eq emissions will be referenced from the Level 1 methodology contemplated in work carried out by the IPCC, according to (28.a). In this case, the energy production is converted to a gross equivalent by applying a factor to the net production of generator g.

The CO_2 equivalent contributions of other greenhouse gases such as CH4 and N_2O were considered. The emission factors listed in Table 2 were selected from Ref. [36].

The fuel emission factor must be multiplied by its global warming potential (GWP) to convert to CO_2eq in a period base of 100 years [37]. CO_2eq emissions are shown in (28.b). According to the IPCC level 1 methodology, the quantification of CO_2eq emissions was determined from expression (28.c). The CO_2eq emissions were estimated to range from (28.d), and the variations were verified at (28.e). Expression (28.f) was used to calculate the emissions avoided by variable renewable energies, and (28.g) performed the same calculations as the baseline. The change in emissions avoided by the participation of variable renewables was determined in (28.h).

TABLE 2. Fuel type emission factors.

Fuel	Default emission factor		
	[gCO_2/kJ]	[gCH_4/kJ]	[gN_2O/kJ]
Anthracite	0.0983	0.000001	0.0000015
Fuel oil # 6	0.0774	0.000003	0.0000006
Fuel oil # 2	0.0741	0.000003	0.0000006
Natural gas	0.0561	0.000001	0.0000001

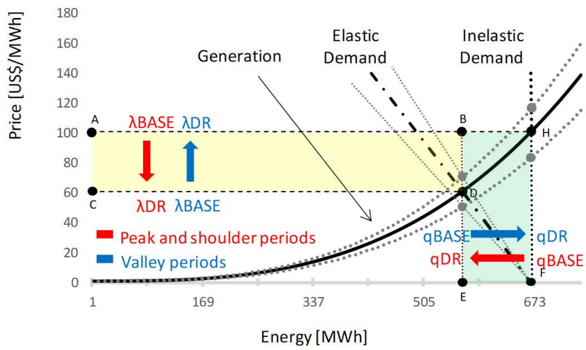

FIGURE 5. Cost and quantity variations due to elasticity change. Source: Modified from [38].

IV. MEASUREMENTS, RESULTS, AND DISCUSSION

A. MEASUREMENTS

A consumer's decision to participate in the DRP adds a benefit incentive, calculated as a function of the load size. The consumers' net benefit is determined from the variations in the marginal cost and demand for each hour, day, and bus, as illustrated in Fig. 5.

The performance indicators related to demand and used in this work are the net profit for participants in the DRP in (29), net profit for non-participants in the DRP in (30), percentage variations in electricity load during peak hour block in (31.a), percentage variations in electricity load during the off-peak hour block (31.b), and percentage ratio of non-served power concerning baseline consumption in (31.c).

$$\begin{aligned} pDR_{b,\omega} = \sum_{day} \sum_{hr} \Big[& \left(qBASE_{b,day,\omega,hr} - qDR_{b,day,\omega,hr}\right) \times fPC_{b,day,\omega,hr} \\ & \times \lambda BASE_{b,day,\omega,hr} + \left(\lambda BASE_{b,day,\omega,hr} - \lambda DR_{b,day,\omega,hr}\right) \\ & \times \vartheta \times fPC_{b,day,\omega,hr} \times qDR_{b,day,\omega,hr} \Big] \\ & + \left[\frac{\left(\sum_{day} \sum_{hr} fPC_{b,day,\omega,hr} \times qDR_{b,day,\omega,hr}\right)}{\left(\sum_b \sum_{day} \sum_{hr} fPC_{b,day,\omega,hr} \times qDR_{b,day,\omega,hr}\right)} \right] \\ & \times objMOD_2 \quad \forall b, day, \omega, hr \end{aligned} \tag{29}$$

$$npDR_{b,\omega} = \sum_{day}\sum_{hr}\left[\left(\lambda BASE_{b,day,\omega,hr} - \lambda DR_{b,day,\omega,hr}\right) \times (1-\vartheta) \times fNC_{b,day,\omega,hr} \times qDR_{b,day,\omega,hr}\right] - \left[\frac{\left(\sum_{day}\sum_{hr} fPC_{b,day,\omega,hr} \times qDR_{b,day,\omega,hr}\right)}{\left(\sum_{b}\sum_{day}\sum_{hr} fPC_{b,day,\omega,hr} \times qDR_{b,day,\omega,hr}\right)}\right] \times objMOD_2 \quad \forall b, day, \omega, hr \tag{30}$$

$$\Delta LOAD_{pk_b} = \frac{\sum_p \left(qBASE_{b,p} - qDR_{b,p,\omega}\right)}{\sum_p qBASE_{b,p}} \times 100 \quad \forall\, b, p\,(1to6)\,, \omega \tag{31.a}$$

$$\Delta LOAD_{offpk_b} = \left[\frac{\sum_{6<p\leq 18}\left(qBASE_{b,p} - qDR_{b,p,\omega}\right)}{\sum_p qBASE_{b,p}} + \frac{\sum_{19<p\leq 24}\left(qDR_{b,p,\omega} - qBASE_{b,p}\right)}{\sum_p qBASE_{b,p}}\right] \times 100 \quad \forall\, b, p\,(7to24)\,, \omega \tag{31.b}$$

$$rNSP_b = \frac{\sum_p nsp_{b,p}}{\sum_p qBASE_{b,p}} \times 100 \quad \forall\, b, p \tag{31.c}$$

The case study analyzes the methodology applied to the operation schedule for one week in the Dominican Republic. The network was scaled using a modified IEEE standardized network of 14 buses; the inputs, configurations, and topologies are specified in the Appendix.

In operational and economic terms, generation dispatch must be carried out at minimum cost and safely, motivating the modeling to provide reserve margins for the frequency regulation service. Under the methodological proposal, a new DR service is incorporated, based on the partial displacement of the load from peak and shoulder periods to valley periods in the load curve, and taking advantage of the availability of the variable renewable resource.

A simplified model based on the optimal power flow in direct current (OPF-DC) was used for the assumptions considered when applying this methodology. Although reactive power occupies a part of the transmission lines' capacity, its magnitude is much smaller than active power. This argument simplifies the optimization model; therefore, it is assumed that there are no voltage problems in the system buses.

The results of the model 0 runs represent the baseline. Model 1 then determines the load transfers that can be made between the hourly blocks of the load curve as a function of the elasticity of substitution and cost constraints. According to the DRP incentive scheme, model 2 solves the hourly distribution of the new demand, and model 3 incorporates the environmental component, leading to the final results and discussion.

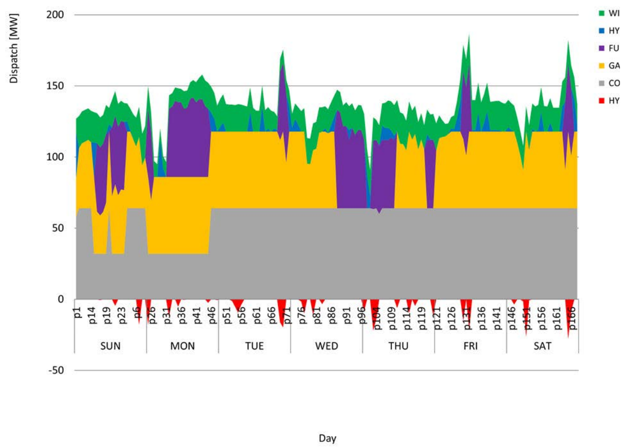

FIGURE 6. Dispatch of generation for baseline.

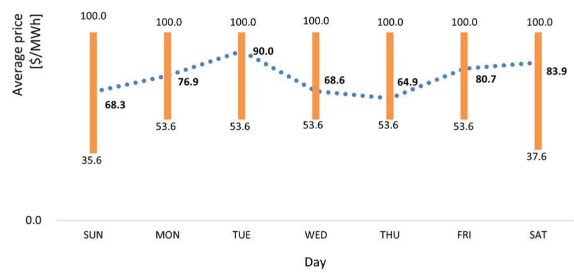

FIGURE 7. Average and range of LMP for baseline.

B. MODEL 0 RESULTS

The system operator was optimized to minimize the supply cost during the coordination process. This model shows a generation dispatch that requires 86% fossil fuel and 14% renewable participation. The generation of the dispatch schedule is illustrated in Fig. 6. A change in the availability of coal generators operating at the minimum technical value between P16 and P44 was simulated. In addition, one daily start-up was configured for the thermal plants and two for the hydro plants.

The absence of a hydrothermal model in the Dominican Republic's electricity market does not make it possible to incorporate opportunity costs. However, this exercise has considered its declaration, considering that the regulations allow it and provide a signal of prioritization for other water uses, such as drinking water and irrigation of crops, which require maintaining certain reservoir levels. Therefore, the hydroelectric generation reached 1.84% of the total generation. Additionally, pumping activity is included to take advantage of periods of low prices and, in other cases, to create conditions of balance between generation and demand, representing 68.8% of hydroelectric participation. On the other hand, wind generation prioritizes dispatch because it is a price-taker.

The variability in the local marginal price between a maximum price of \$100/MWh and a minimum price of \$37.6/MWh is observed, as shown in Fig. 7.

Fig. 8 shows the balance between generation and demand. In this coverage, it is observed that 2.8% of the load represents

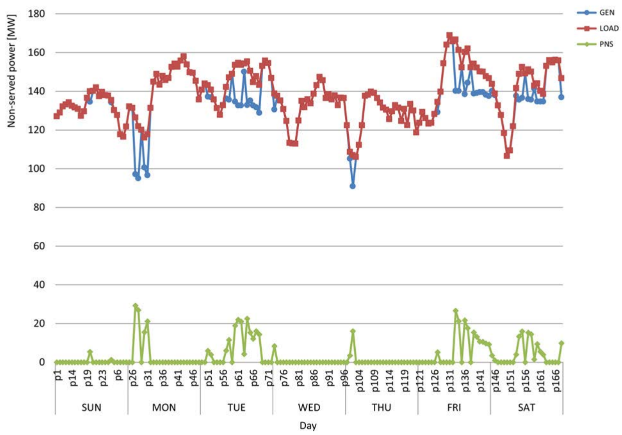

FIGURE 8. Non-served power for baseline.

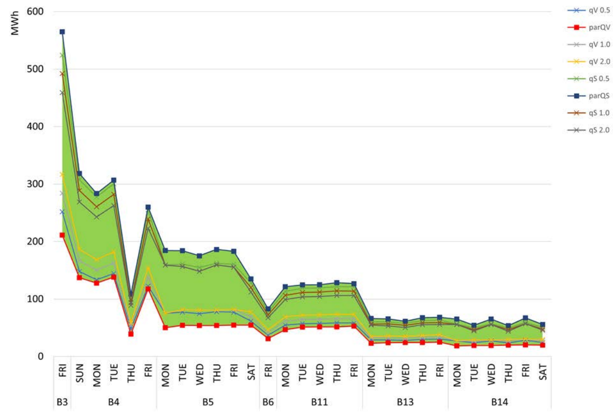

FIGURE 10. Effect of the substitution parameter to shift load from shoulder to valley periods.

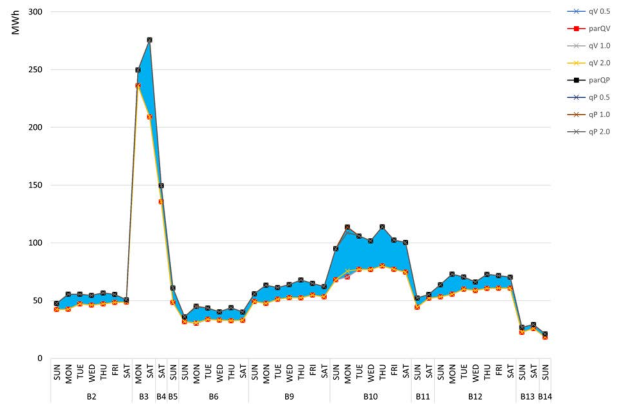

FIGURE 9. Effect of the substitution parameter to shift load from peak to valley periods.

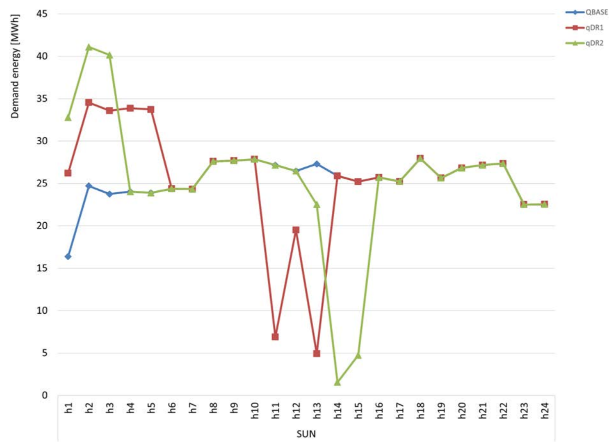

FIGURE 11. Demand response vl ← sh for bus 4, Sunday, and scenarios 1,2.

non-served power owing to the limitations inherent to the transmission lines.

C. MODEL 1 RESULTS

The sensitivity of the CES function can be appreciated with the test values of the substitution parameters 2.0, 1.0, and 0.5, and their corresponding constant elasticities of 0.33, 0.50, and 0.66, in the objective of the partial shift of demand from peak and shoulder periods to valley periods in the daily load curve.

The elasticity of substitution shows a saturated sensitivity, with no significant shifts from peak to valley, contrary to what was observed from the shoulder to the valley. In Fig. 9, the mean of the relative demand variations reaches 0.10% during the peak periods, whereas in Fig. 10, the mean is 16.5% during the shoulder periods.

D. MODEL 2 RESULTS

The decision to assume variability characterized by the elasticity of substitution is conditioned by an incentive scheme that allows the hourly distribution of demand. For this simulation, the shifted demand with substitution parameter 2.0 was considered. A DRP incentive amounting to \$103,124.09 has also been determined. The apportionment of this amount was based on the DRP share.

A sample of demand scenarios 1 and 2 presents the corresponding results for bus 4 on Sunday and bus 10 on Monday, as shown in Figures 11 and 12, which shift the load from shoulder to valley and peak to valley, respectively. The hourly distribution of the demand scenarios (1 and 2) depends on the incentive scheme, probability of occurrence (75%,25%), and lower and upper limits of variation that were set ($> 10\%|$). In Fig. 11, the two optimal scenarios show a shift of 49 MWh in energy consumption for a relative reduction of 15.6% in the demand block corresponding to the shoulder periods. In contrast, in Fig. 12, 5.1 MWh is reduced for a relative change of 4.5% in energy consumption in the demand block of the peak periods, motivating an additional load in the valley periods.

E. MODEL 3 RESULTS

Initially, the baseline electricity supply operating cost was verified by considering the mandatory participation of the variable renewables. Without the renewable cap constraint, the objective function reaches \$1,019,294.25. When the

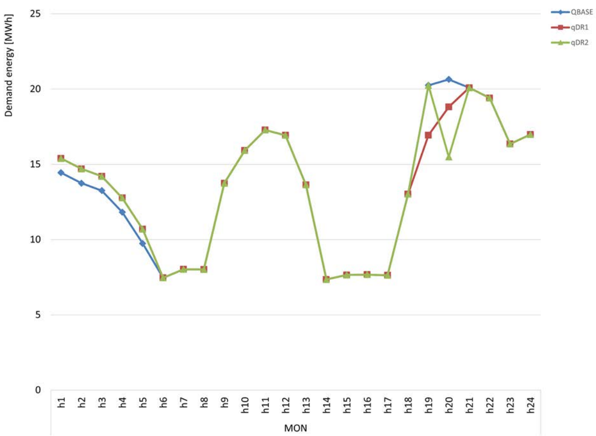

FIGURE 12. Demand response vl ← pk for bus 10, Monday, and scenarios 1,2.

TABLE 3. Results of the objective function considering constraints.

PARAMETER OF SUBSTITUTION	EFFECT OF CO_2 CONSTRAINTS	RENEWABLE PENETRATION [%]	OBJECTIVE FUNCTION [$]
0.5	No	No	1,016,958.16
	No	Yes	1,017,528.75
	Yes	No	1,181,276.89
	Yes	Yes	1,181,743.34
1.0	No	No	1,017,895.47
	No	Yes	1,018,400.43
	Yes	No	1,183,932.94
	Yes	Yes	1,183,724.40
2.0	No	No	1,017,238.79
	No	Yes	1,017,133.54
	Yes	No	1,183,383.73
	Yes	Yes	1,183,765.32

constraint was included in the model to ensure a minimum penetration between 11% and 12%, the cost increased to $1,020,204.92. The same exercise was performed considering demand response scenario 1 for each substitution parameter analyzed and was used to verify the effect on the CO_2 emissions limit, as shown in Table 3.

Regarding the base case, the scenarios corresponding to a limit of renewables participation do not present a significant variation in the objective function because the reductions are less than 0.4%. However, the effect of incorporating CO_2 constraints motivates changes in demand response. The simulation shows increments between 15.8 and 16.2% when the price is $10 per ton of CO_2. Observing that the substitution parameters caused moderate changes in the objective function, other results were analyzed by selecting a substitution parameter equal to 2.

TABLE 4. Results of generation indicators.

CASE	OBJECTIVE FUNCTION $	OBJECTIVE FUNCTION Δ% respect case base	BUS	WIND WPEN (%)	COAL Ton CO_2 (Δ%)	GAS Ton CO_2 (Δ%)	FUEL Ton CO_2 (Δ%)	WIND EEA (Δ%)
Demand 1	1,183,765	16.03%	b1		-0.70			
			b2			0.47		
			b3				-2.95	
			b6	12.00				-0.12
	1,094,424	7.27%	b1		-0.29			
			b2			-6.40		
			b3				-21.34	
			b6	17.00				41.52
Demand 2	1,181,959	15.86%	b1		-0.20			
			b2			0.92		
			b3				-3.49	
			b6	12.00				-0.12
	1,094,461	7.28%	b1		-0.34			
			b2			-7.29		
			b3				-13.14	
			b6	17.00				41.52

Tables 4 and 5 analyze the generation and demand indicators after applying the methodology to the two demand shift scenarios. In each case, comparisons were made with the objective function in the baseline for an initial variable renewable energy penetration of 12% (similar to the maximum allowable in the baseline) and another of 17%, corresponding to the maximum allowed with the demand response program. The results verify that the increase in renewables reduces the operating cost of generation dispatch, similar to the results observed by [39]. The simulations consider the mitigation of CO_2 emissions, causing the objective function to be higher than the corresponding baseline function, with relative variations ranging from 7.27% to 16.03%, and a reduction of tons of CO_2 equivalent, from 2.77 to 28.02. If the CO_2 emissions cost is reduced to zero, renewables can increase by 5%. This reduction in CO_2 cost translates into a supply cost of -8.4%, compared to the baseline.

It is also observed that the incentive allowed all the participants in the DRP to be compensated favorably. The loads connected to buses 3 and 4 are incentivized in periods when demand is used and discouraged in periods that do not participate. The results include all consumers, the incentive scheme, benefits of price and quantity reduction, and the losses due to the increases according to the corresponding hourly block. These balances were defined according to the participation criteria. They represent only profits or losses, motivating the need to configure a regulatory scheme.

Another aspect to consider is the relative variation in the load produced by the elasticity of substitution, from 0.1% to 10.49% in the peak and shoulder blocks, and from 0.94% to 42.13% in the valley block. In the case of non-served power, buses 2 and 5 show critical relative increases, in the worst-case scenario, the non-served power reaches variations of 15.38% and 15.12%, respectively, and 4.78% and 5.69%, respectively, in the best case. Despite this behavior of the non-served power per bus, there is a notable reduction of 19.1% compared to the baseline.

F. DISCUSSION

1) MAXIMUM DEMAND

In general, the coincident maximum hourly demand for the weekly schedule changes from one demand block to another.

TABLE 5. Results of demand indicators.

CASE	BUS	NET PROFIT		LOAD			
		pDR ($)	npDR ($)	pkLD (Δ%)	npkLD (Δ%)	rNSP (Δ%)	rNSP (%)
Demand 1	b2	6,695.25		0.13		-90.50	15.38
	b3	15,248.43	(33,553.82)	2.08	-6.01	-93.80	0.06
	b4	11,788.39	(1,696.32)	8.31	-24.36	-94.92	1.61
	b5	10,473.64		9.56	-41.95	-95.78	15.12
	b6	5,252.91		2.12	-6.91	-51.60	0.92
	b9	7,289.73		0.11			0.54
	b10	11,429.85		0.33			0.12
	b11	7,030.16		8.77	-0.94		0.39
	b12	8,393.45		0.10	-30.15		0.60
	b13	3,636.97		9.54	-34.08		1.52
	b14	3,170.08		10.49	-42.13	-43.42	2.89
	b2	8,416.22		0.13		-95.36	7.51
	b3	22,769.53	(32,330.41)	2.08	-6.01	-99.30	0.01
	b4	16,335.49	(1,375.93)	8.31	-24.36	-99.48	0.17
	b5	12,284.14		9.56	-41.95	-97.56	8.74
	b6	6,445.63		2.12	-6.91	182.18	5.36
	b9			0.11			
	b10	14,833.44		0.33			
	b11	8,916.74		8.77	-0.94		3.28
	b12	10,667.63		0.10	-30.15		0.52
	b13	4,656.16		9.54	-34.08		2.89
	b14	4,463.35		10.49	-42.13	-91.42	0.44
Demand 2	b2	6,869.82		0.13		-90.52	15.35
	b3	17,699.54	(34,074.34)	2.08	-6.01	-89.28	0.11
	b4	15,445.39	(2,539.27)	8.31	-24.35	-97.35	0.84
	b5	11,455.44		9.55	-41.98	-96.48	12.61
	b6	5,601.71		2.12	-6.96	-24.66	1.43
	b9			0.11			0.49
	b10	11,638.20		0.33			0.77
	b11	7,929.06		8.79	-0.94		1.07
	b12	8,655.02		0.10	-30.10		1.06
	b13	3,790.06		9.52	-34.20		1.12
	b14	3,197.61		10.49	-42.13	-89.75	0.52
	b2	9,813.25		0.13		-97.05	4.78
	b3	27,396.36	(17,892.98)	2.08	-6.01	-98.69	0.01
	b4	19,758.04	(1,119.41)	8.31	-24.35	-98.68	0.42
	b5	16,361.51		9.55	-41.98	-98.41	5.69
	b6	7,715.75		2.12	-6.96	46.71	2.79
	b9	10,727.71		0.11			
	b10	17,008.07		0.33			0.53
	b11	11,685.94		8.79	-0.94		2.16
	b12	12,399.70		0.10	-30.10		0.23
	b13	5,349.63		9.52	-34.20		0.69
	b14	5,020.53		10.49	-42.13	-77.57	1.14

The maximum demand was recorded for period 131 at the baseline's 11th hour of the sixth day. After applying the load shift, the new period was 125: the 5th hour of the sixth day. It should be noted that the maximum demand at baseline corresponds to a shoulder hour. However, based on a reduced selection that considers different load profiles, depending on the type of end-user, accurate information is registered by the operator of the wholesale electricity market in the Dominican Republic. The results show a reduction in the non-served power of 19.1% when the renewable energy penetration level increases by 5%.

The change in the time of occurrence of maximum demand to a period not considered within the administrative hours defined for the peak period occurs with 93.5% of the users in the DRP. This result should not be taken lightly, even though the actual calculation process is handled with the accumulated horizon of the entire year, because it may result in differences between a real off-peak maximum demand, which is more significant than the one considered on-peak from the perspective of the regulation of the wholesale electricity market in the Dominican Republic. This regulatory condition is vulnerable because the valley, shoulder, and peak periods are defined administratively and not based on scarcity. Reduction in the distribution parameters of the CES function and the number of participants in the DRP should be considered.

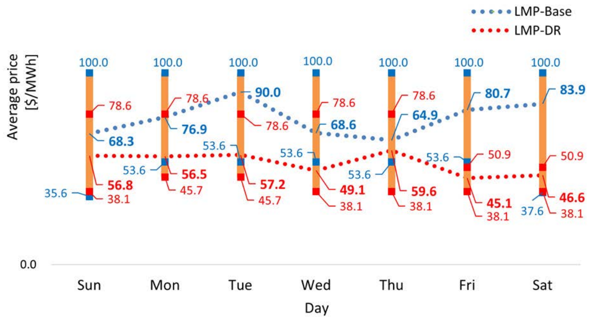

FIGURE 13. Comparison of LMP in models 0 and 3.

2) LOCAL MARGINAL PRICE

The reduction in non-served power is also explained by the reduction of the LMP, as the variability is reduced from the upper end, which reaches the price-cap limit in the baseline. Fig. 13 compares the LMP averages and variation ranges for the baseline situation and the corresponding values with the DRP.

3) HYDROELECTRIC GENERATION

Regarding the behavior of hydroelectric production during dispatch, we observed the application of reservoir restrictions to simulate the limitation of its availability and the cost of water production. In this regard, it should be noted that the Dominican Republic does not have large flows or reservoirs, which reduces the possibility of developing large-scale hydroelectric projects. Therefore, investment initiatives consider their feasibility by considering additional solutions to energy production, such as the supply of drinking water for consumption, irrigation canals for agriculture, and flood prevention in vulnerable areas. This variety of uses implies the establishment of priorities and justifies the rationality of defining the opportunity cost of water.

4) CES FUNCTION

The ordering of the iterations for the load displacements employing the CES function has to do with the levels that limit the load placement in the valley hour block because less load than desired can be transferred in the second iteration if the maximum limit is reached with the first one, resulting in low sensitivity in the CES function.

5) SOFTWARE TOOL OPPORTUNITY

The case study has been oriented to take advantage of the total availability of renewable resources and to reduce the total non-served power in hourly blocks. One of the most important uses of the tool to take advantage of the operation schedule would be the realization of punctual load shifts in the hours with non-served power problems in connection points and in the transmission lines where congestion problems are identified, towards periods that have the required slack conditions.

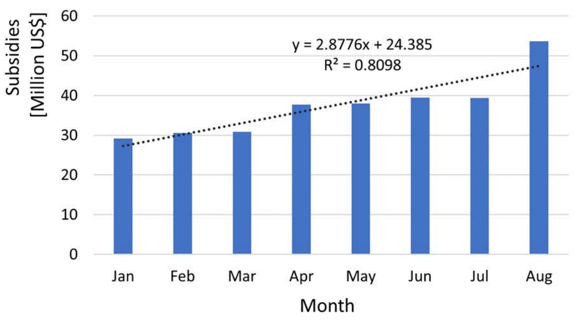

FIGURE 14. Estimated subsidies for distribution tariffs.

The uncertainty associated with the declaration of the weekly availability of variable renewables justifies revisions of the schedule in shorter periods, motivating daily and intra-daily updates. Regulations provide daily updates in the Dominican market.

Currently, the wholesale electricity market in the Dominican Republic does not have tools that handle this concept with optimization criteria to address its evolution from the perspective of energy transition and climate change.

6) NEW DEMAND TYPE

Just as the added value of generation and transmission is planned, it is expected that in the coming years, the demand in the Dominican Republic will grow above its natural behavior as a result of the penetration of electric mobility, which must also be planned for its contribution to DR services. This requires adaptation of the tool to consider the vehicle fleet as a possible participant in the DRP. The institutions responsible for its regulation must standardize the electrical installations required for recharging and service facilities.

7) SUBSIDIES

According to the official publications of the Superintendence of Electricity of the Dominican Republic [40], the subsidy on the distribution tariff that the state grants to regulated users of the public electricity service reached US$298.67 million during the first eight months of 2021, as shown in Fig. 14. The financial situation of electricity distribution companies could be more critical if the regulatory authority of the electricity sector does not limit the maximum price of energy purchases in the wholesale electricity market. However, this regulatory policy affects the net social benefits of the other market agents, and the economic prospective of the state, considering the dependence on gross domestic product and energy consumption, as verified in [41].

The net income balance of distribution companies does not exhibit linear behavior due to various factors, such as market price caps, poor collection management, and technical and non-technical losses. The state can establish efficient controls in its internal processes to implement a staggered goal that allows the reduction of the subsidy that complements the distribution tariff and thus redirects its focus towards the poorest sectors of society. Therefore, this methodology can be used to design a policy of gradual dismantling of the subsidy by verifying that in the simulation of the case study, it was possible to achieve a reduction of 30.45% in the average marginal energy costs used for the valuation of distribution companies' consumption in the wholesale electricity market.

8) IMPROVEMENTS IDENTIFIED

The results obtained reveal the consistency of the methodology in the objective of minimizing the operating cost of generation supply, without exceeding the limits established for non-served power and CO_2 emissions, allowing the increase of variable renewables and the economic compensation of the participants in the DRP. In the electricity business, functionalities that contribute to the numerical accuracy of the results are always welcome for decision making. Therefore, the following improvements have been identified to add value in the continuity of this research: i) automatic segmentation of demand based on clustering criteria that consider electrical, economic and technological characteristics; ii) advanced calculation of CO_2 emissions based on IPCC levels 2 and 3; iii) inclusion of a variable renewables forecasting module, based on variables supported by the meteorological service; and iv) consideration of transmission losses, due to their relevance in the determination of non-served power.

V. CONCLUSION

This study presents a market methodology designed to integrate and evaluate a demand response program in the wholesale electricity market in the Dominican Republic. The optimization problem is structured in four stages: an economic dispatch of the generation that defines the operating cost of supply, the load displacement from the CES function, the distribution of hourly demand based on an incentive scheme, and a new dispatch that incorporates the control of CO_2 emissions.

The simulation of the case study showed favorable results in taking advantage of the availability of the variable renewable resource, allowing a 5% increase in penetration compared to the baseline, a 30.5% reduction in the average marginal energy costs, an 8.4% reduction in the operating cost of supply, and a 19.1% reduction in non-served power. In addition, it was possible to verify the favorable results of the incentives that benefit the participants in the DRP. This last contribution can be linked to a regulatory policy that mitigates deviations in generation availability and declared demand for operational scheduling.

The application of this methodology has limitations when the demand blocks saturate the sensitivity of the CES function because the effect of load shifting is minimal or does not occur, as evidenced in the iterations from peak to valley of the case study, where variations of less than 5% of the base demand are verified despite having limits that allow it. Regarding the incentive scheme, establishing the upper limit that defines its variability during the optimization process should be considered. High incentives may distort the nature of the regulation mechanism and low values may not

TABLE 6. Typification of variables, parameters, and scalars.

CONCEPT DESCRIPTION	UNIT	ABBREVIATION	VARIABLE TYPE	MODEL			
				0	1	2	3
Start-up cost of generator t	\$/h	SUC_t		par			par
Shut-down cost of generator t	\$/h	SDC_t		par			par
Non-fuel cost of generator t	\$/h	NFC_t		par			par
Variable fuel cost of generator t	\$/MWh	VFC_t		par			par
Factor to refer net to a gross production of generator g	p.u.	σ_t		par			par
Wind cost of generator w	\$/MWh	C_w		par			par
Water Value of generator h (turbined or pumped)	\$/MWh	C_h		par			par
Wind energy forecast by generator h during period p	MW	$WEF_{g,p}$		par			par
The efficiency of pumping equipment h	p.u.	η_h		par			par
Value of loss load	\$/MWh	VOLL		par			par
Base demand in bus b during period p	MW	$qBASE_{b,p}$		par			
Percentage of total demand	%	δ		s			s
Natural contribution to reservoir	MWh	NCR		s			s
Initial equivalent energy at reservoir level	MWh	RINI		s			s
Final equivalent energy at reservoir level	MWh	RFIN		s			s
Maximum available energy of the reservoir	MWh	$r^{MAX}{}_h$		par			par
Minimum available energy of the reservoir	MWh	$r^{MIN}{}_h$		par			par
Total demand	MW	TLOAD		s			s
Maximum power of generator g	MW	$P^{MAX}{}_g$		par			par
The minimum power of generator g	MW	$P^{MIN}{}_g$		par			par
Percentage of primary reserve requirement during period p	%	ψ		par			par
Parameter of the transmission line i - j $\rightarrow$ reactance	Ω	$X_{i,j}$		par			par
Maximum power flow through line i - j for each period	MW	$pTX^{MAX}{}_{i,j}$		par			par
Minimum power flow through line i - j for each period	MW	$pTX^{MIN}{}_{i,j}$		par			par
Maximum voltage phase angle in bus b	rad	$\theta^{MAX}{}_b$		par			par
Minimum voltage phase angle in bus b	rad	$\theta^{MIN}{}_b$		par			par
Up ramp of generator g	MW	$R^{UP}{}_g$		par			par
Down the ramp of generator g	MW	$R^{DOWN}{}_g$		par			par
Maximum pumping power of generator h	MW	$epump^{MAX}{}_h$		par			par
Duration of period p	h	d_p		par			par

TABLE 6. ***(Continued.)*** **Typification of variables, parameters, and scalars.**

Wind penetration	%	WPEN		par			par
Daily start-ups for fossil generation		$limSU_{f,day}$		par			par
Daily start-ups for hydro generation		$limSU_{h,day}$		par			par
Maintenance declaring of generator		$MD_{g,p}$		par			par
Availability declaring of fossil generator	MW	$AD_{g,p}$		par			par
Daily efficiency parameter of CES function	%	$\gamma_{b,day}$			par		
Substitution parameter for CES function		ρ			s		
The daily distribution ratio of the CES function		$\alpha_{b,day}$			par		
Scale in CES function		$\phi_{b,day}$			par		
Daily demand block during iteration #	MW	$q_{b,day,db,iter}$	state		v		
The budget represents the daily utility value for a specific demand block in the CES function.	$	$V_{b,day,db}$			par		
The budget represents the initial daily utility value for demand blocks involved in the CES function.	$	$BVAL^{db1\leftarrow db2}{}_{b,day}$			par		
The upper limit of daily demand block during iteration #	MW	$q^{MAX}{}_{b,day,db,iter}$			par		
The lower limit of daily demand block during iteration #	MW	$q^{MIN}{}_{b,day,db,iter}$			par		
Maximum flexible demand per bus	MW	$Q^{MAX}{}_{b}$				par	
Minimum flexible demand per bus	MW	$Q^{MIN}{}_{b}$				par	
Maximum load increase that can be consumed by flexible demand k between adjacent periods	MW	$Q^{UP}{}_{b}$				par	
Minimum load reduction that can be consumed by flexible demand k between adjacent periods	MW	$Q^{DOWN}{}_{b}$				par	
Flag for participating consumers in DRP		$fPC_{b,day,\omega,h}$					par
Flag for non-participating consumers in DRP		$fNC_{b,day,\omega,h}$					par
The conversion factor for thermal performance of generator f	kJ/kWh	β					par
Climate change potential of fuel for 100 years		GWP_{100}					par
CO_2 emission factor by type of gei and fuel for generator g	gCO_2/kJ	$EF^{CO2}{}_{g,gei}$					par
CO_2 emission factor determined as simple operation margin by IPCC method	gCO_2/kWh	$EF^{OM}{}_{w}$					par
The CO_2 emission limit for generator t	Ton of CO_2	ET_t					par
Price of CO_2 emissions	$/Ton of CO_2	μ					s
Base power	MW	SB		s			s
Base time duration	h	d_p		par			par
Power flows into bus j from bus i during hour p	MW	$flow_{i,j,p}$	state	v			v
Power flows into bus i from bus j during hour p	MW	$flow_{j,i,p}$	state	v			v
Voltage angle at node b during period p	rad	$\theta_{b,p}$	state	v			v
Residual of linearized CES function for daily iterations		$res_{b,day,iter}$	decision		v		

TABLE 6. ***(Continued.)*** **Typification of variables, parameters, and scalars.**

Variations in electricity load during a peak hour block	%	$\Delta LOAD_{pk}$	report			v	
Variations in electricity load during the off-peak hour block	%	$\Delta LOAD_{offpk}$	report			v	
Power of generator g in period p	MW	$e_{g,p}$	decision	v			v
Power of generator g in period p determined in MOD-0	MW	$eBASE_{g,p}$					par
Power of pumping equipment h in period p	MW	$epump_{h,p}$	decision	v			v
Non-served power in bus b and period p	MW	$nsp_{b,p}$	decision	v			v
Total primary frequency reserve margin during period p	MW	$MPFR^{TOT}{}_{p}$	state	v			v
Power of Generator g above the minimum value during period p	MW	$e^{\uparrow MIN}{}_{g,p}$	state	v			v
The incentive of participant demand in DRP, during period p, in scenario ω	\$/MWh	$\lambda INC_{b,day,\omega,h}$	decision			v	
Purchase price of demand k in DR condition, during period p, in scenario ω	\$/MWh	$\lambda DR_{b,day,\omega,h}$	dual				v
Purchase demand price for case base, during period p, in scenario ω	\$/MWh	$\lambda BASE_{b,day,\omega,h}$	dual (Model 0)	v			par
Flexible demand, during period p, in scenario ω	MW	$qDR_{b,day,\omega,h}$	decision (Model 2)			v	par
The maximum value during the weekly load curve in bus b	MW	$qREF^{MAX}{}_{b,\omega}$				par	
The minimum value during the weekly load curve in bus b	MW	$qREF^{MIN}{}_{b,\omega}$				par	
Probability of occurrence of scenario ω	%	π_{ω}				par	
The proportion of market price to define the upper limit of DRP incentive	%	ζ_{ω}				par	
CO_2 emissions from each thermoelectric generator during period p	Ton of CO_2	$ee^{CO2}{}_{t,p}$	decision				v
CO_2 emissions from each thermoelectric generator in base case during period p	Ton of CO_2	$eeBASE^{CO2}{}_{t,p}$	decision				v
Variations in CO_2 emissions for thermoelectric generator t	%	ΔEE_{t}	report				v
CO_2 emissions avoided from each wind generator during period p	Ton of CO_2	$eeA^{CO2}{}_{w,p}$	report				v
CO_2 emissions avoided from each wind generator in base case during period p	Ton of CO_2	$eeABASE^{CO2}{}_{w,p}$	report				v
Variations in CO_2 emissions avoided for wind generator w	%	ΔEEA_{w}	report				v
Net profit for participants customers in DR program per bus in scenario w	\$	$pDR_{b,w}$	report				v
Net profit for non-Participants customers in DR program in scenario w	\$	$npDR_{b,w}$	report				v
Percentage of the total benefit produced by price variations for DRP participants	%	v	report				par
The percentage ratio of non-served power concerning baseline consumption	%	rNSP	report				v
On/Off states for generation g during period p		$u_{g,p}$	binary	v			v
Start-up decision for generation g during period p		$y_{g,p}$	binary	v			v
The shut-down decision for generation g during period p		$z_{g,p}$	binary	v			v
The objective function in MOD0		$objMOD_{0}$	decision	v			
The objective function in MOD 1 for the initial iteration		$objMOD^{ini}{}_{1}$	decision		v		
The objective function in MOD 1 for the final iteration		$objMOD^{fin}{}_{1}$	decision		v		
The objective function in MOD 2		$objMOD_{2}$	decision			v	par
The objective function in MOD 3		$objMOD_{3}$	decision				v

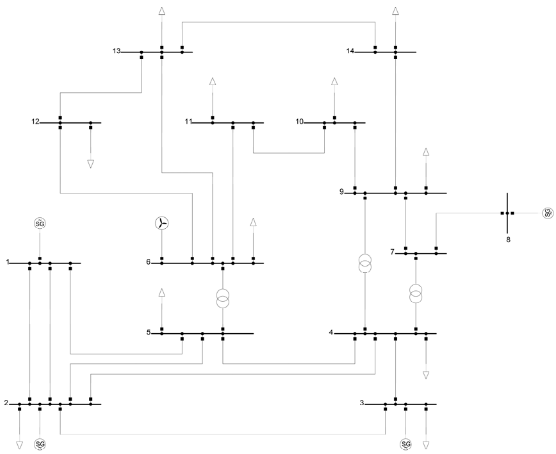

FIGURE 15. Modified IEEE 14-bus system.

TABLE 7. Bus connection assignment point in the network.

ACTIVITY	AGENT	BUS	GROUP
Generation	Generator	b1	Coal
		b2	Gas
		b3	Fuel
		b6	Wind
		b8	Hydro
Demand	Distribution	b2	Residential/Commercial
		b5	Residential/Commercial
		b9	Residential
		b10	Residential/Commercial
		b11	Residential/Commercial
		b12	Residential/Commercial
		b13	Residential
		b14	Residential
	Non-Regulated User	b3	Industrial (Mining)
		b4	Industrial (Mining)
		b6	Industrial (Free zone)

be attractive, considering that some participants in the DRP would not have benefits. Another aspect that contributes to reliable results is the quality of the wind-resource forecasting service.

The indicated limitations should be considered for future research on this topic. Thus, the methodology can be improved by forecasting variable renewables, exploring model-based criteria for demand segmentation, and losses in transmission activity to reduce deviations during operations. Another aspect to consider in future research is the treatment of the demand disutility function, considering that this is the main barrier for the demand side to exercise flexibility. If not adequately examined, assessing the benefits of demand flexibility may be overly optimistic. The addition of these functionalities would be beneficial for strengthening the consistency and validity of the results. In addition, the optimization model can be adapted to determine the behavior of CO_2 emissions at levels 2 and 3 of the methodology developed by the IPCC, allowing their differences with related studies and the sense of application in the electricity sector

TABLE 8. Line parameters of IEEE 14-bus system.

BUS		LINE PARAMETERS		
from	to	r (p.u.)	x (p.u.)	pmaxline (MW)
b1	b2	0.01938	0.05917	120
b1	b5	0.05403	0.22304	65
b2	b3	0.04699	0.19797	36
b2	b4	0.05811	0.17632	65
b2	b5	0.05695	0.17388	50
b3	b4	0.06701	0.17103	65
b4	b5	0.01335	0.04211	45
b4	b7	0	0.20912	55
b4	b9	0	0.55618	32
b5	b6	0	0.25202	45
b6	b11	0.09498	0.1989	18
b6	b12	0.12291	0.25581	32
b6	b13	0.06615	0.13027	32
b7	b8	0	0.17615	32
b7	b9	0	0.11001	32
b9	b10	0.03181	0.0845	32
b9	b14	0.12711	0.27038	32
b10	b11	0.08205	0.19207	12
b12	b13	0.22092	0.19988	12
b13	b14	0.17093	0.34802	12

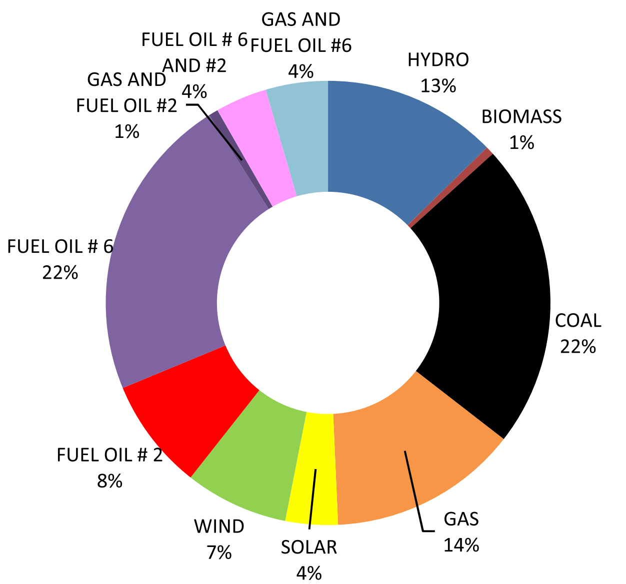

FIGURE 16. Installed capacity according to a primary energy source in the electric power system of the Dominican Republic. Source: [42].

TABLE 9. Data input parameters of generation cost.

GENERATOR TYPE	SUC_t ($/h)	SDC_t ($/h)	NFC_t ($/h)	VFC_t ($/MWh)	C_h ($/MWh)	C_w ($/MWh)
Coal	200.0	20.0	15.0	37.6		
Gas	250.0	25.0	10.0	53.6		
Fuel	300.0	30.0	20.0	72.1		
Hydro					10.0	
Wind						0.0

TABLE 10. Data input parameters of generation power.

GENERATOR TYPE	P^{MAX}_g (MW)	P^{MIN}_g (MW)	R^{UP}_g (MW)	R^{DOWN}_g (MW)	$conv_g$ (p.u.)
Coal	64.0	32.0	40.0	40.0	1.0
Gas	54.0	27.0	40.0	40.0	1.0
Fuel	96.0	48.0	40.0	40.0	1.0
Hydro	38.0	0.0	38.0	38.0	1.0
Wind	50.0	0.0	33.0	33.0	1.0

TABLE 11. Data input scalars.

CONCEPT DESCRIPTION	UNIT	ABBREVIATION	TEST VALUE
Percentage of total demand	%	δ	3
Total demand energy	MWh	TLOAD	23209.7
Base power	MW	SB	100
Value of loss load	$/MWh	VOLL	100
Natural contribution to reservoir	MWh	NCR	1
Initial equivalent energy at reservoir level	MWh	RINI	30
Final equivalent energy at reservoir level	MWh	RFIN	25
Wind penetration	%	WPEN	12 to 17
The conversion factor for the unit of thermal performance	kJ/kWh	β	1.0551
Price of CO_2 emissions	$/Ton of CO_2	μ	10
Emission factor OM in the Dominican Republic	gCO_2/kWh	EF^{OM}	630
Substitution parameter		ρ	0.5 to 2
The benefit produced by price variations for DRP participants	%	ν	25

of the Dominican Republic) to support the energy transition processes.

APPENDIX

A. VARIABLES, PARAMETERS, AND SCALARS

Table 6 shows the variables (v), parameters (par), and scalars (s) used in the modellingmodelling methodology.

TABLE 12. Data input of other parameters.

CONCEPT DESCRIPTION	UNIT	ABBREVIATION	REGISTER: TEST VALUE	REGISTER: APPLIED TO
Maximum angle in node voltages	rad	θ^{MAX}_b	1.5	∀ b
Minimum angle in node voltages	rad	θ^{MIN}_b	-1.5	∀ b
Maximum available energy of the reservoir	MWh	r^{MAX}_h	50	∀ h
Minimum available energy of the reservoir	MWh	r^{MIN}_h	20	∀ h
maximum gross pumping power	MW	$epump^{MAX}_b$	38	∀ b
The efficiency of pumping equipment h	p.u.	η_h	0.75	∀ h
The daily distribution ratio of the CES function		$\alpha_{b,day}$	0.25	∀ b,day
Daily efficiency parameter of CES function	%	$\gamma_{b,day}$	100	∀ b,day
Scale in CES function		$\phi_{b,day}$	1	∀ b,day
Probability of demand scenario	%	π_ω	25, 75	∀ ω
Daily start-ups for fossil generation		$limSU_{t,day}$	1	∀ t,day
Daily start-ups for hydro generation		$limSU_{h,day}$	2	∀ h,day
Maintenance declaring of generator		$MD_{g,p}$	23	∀ g(Gas), p(p88 to p110)
Availability declaring of fossil generator	MW	$AD_{g,p}$	64	∀ g(Coal), p(p1 to p14, p46 to p168)
			32	∀ g(Coal), p(p15 to p45)
			54	∀ g(Gas), p
			96	∀ g(Fuel), p

The description of the concept, unit, type of variable, and stage of the model where they are used are indicated in detail.

B. GENERAL SETTINGS ABOUT CONNECTION POINTS

This model solves a cost-based economic dispatch problem by considering the elasticity of substitution as a strategy of the DRP to shift the load from peak to shoulder and valley periods to adjust the daily curve of demand profiles. The DPR effect includes the participation of various renewable

TABLE 13. Design of test boundaries for demand and incentive variables.

CONCEPT	VARIABLES	PARAMETERS	
		LOWER	UPPER
CES Function	$qV_{b,day}$	1.0 x $qVBASE_{b,day}$	1.5 x $qVBASE_{b,day}$
	$qS_{b,day}$	0.75 x $qSBASE_{b,day}$	1.0 x $qSBASE_{b,day}$
	$qP_{b,day}$	0.5 x $qPBASE_{b,day}$	1.0 x $qVPASE_{b,day}$
Demand Scenario 1	$qDR_{b,day,\omega,vl}$	1.0 x $qBASE_{b,day,\omega,vl}$	$qREF^{MAX}_{b,\omega}$ = (1.0 x $qBASE^{MAX}_{b,\omega}$)
	$qDR_{b,day,\omega,sh}$	$qREF^{MIN}_{b,\omega}$ = (0.5 x $qBASE^{MIN}_{b,\omega}$)	1.0 x $qBASE_{b,day,\omega,sh}$
	$qDR_{b,day,\omega,pk}$	$qREF^{MIN}_{b,\omega}$ = (0.5 x $qBASE^{MIN}_{b,\omega}$)	1.0 x $qBASE_{b,day,\omega,pk}$
Demand Scenario 2	$qDR_{b,day,\omega,vl}$	1.0 x $qBASE_{b,day,\omega,vl}$	$qREF^{MAX}_{b,\omega}$ = (1.1 x $qBASE^{MAX}_{b,\omega}$)
	$qDR_{b,day,\omega,sh}$	$qREF^{MIN}_{b,\omega}$ = (0.4 x $qBASE^{MIN}_{b,\omega}$)	1.0 x $qBASE_{b,day,\omega,sh}$
	$qDR_{b,day,\omega,pk}$	$qREF^{MIN}_{b,\omega}$ = (0.4 x $qBASE^{MIN}_{b,\omega}$)	1.0 x $qBASE_{b,day,\omega,pk}$
Incentive Scheme 1	$\lambda INC_{b,day,\omega,vl}$	0	0.5 x $\lambda BASE_{b,day,\omega,vl}$
	$\lambda INC_{b,day,\omega,sh}$	0	0.5 x $\lambda BASE_{b,day,\omega,sh}$
	$\lambda INC_{b,day,\omega,pk}$	0	0.5 x $\lambda BASE_{b,day,\omega,pk}$
Incentive Scheme 2	$\lambda INC_{b,day,\omega,vl}$	0	0.25 x $\lambda BASE_{b,day,\omega,vl}$
	$\lambda INC_{b,day,\omega,sh}$	0	0.25 x $\lambda BASE_{b,day,\omega,sh}$
	$\lambda INC_{b,day,\omega,pk}$	0	0.25 x $\lambda BASE_{b,day,\omega,pk}$

energy sources. The transmission network in the modified IEEE14-bus system, including five different generation technologies, is shown in Fig. 15.

The network topology and transmission capacity were modeled by considering the connection of the generators and the demands in Table 7. The parameters of the lines and transformation elements are presented in Table 8.

C. GENERATION SPECIFICATIONS

Five power plants represent the generation mix, according to the combustion or renewable resources used: coal, fuel, gas, hydraulics with reservoir and pumping characteristics, and a variable renewable source represented by wind power, as detailed in Table 7.

According to the statistics published by [38] in its 2019 annual report, the generation mix composition has the distribution shown in Fig. 16. The exact percentage of each generation technology is assigned to approximate the case study of the electricity system of the Dominican Republic. The remaining parameters were hypothetical and were intended to test the modelling proposed in the methodology. The current variable fuel costs of production (VFC) corresponding to the weekly schedule were used to construct production cost curves. The details of these generation specifications are listed in Tables 9 and 10.

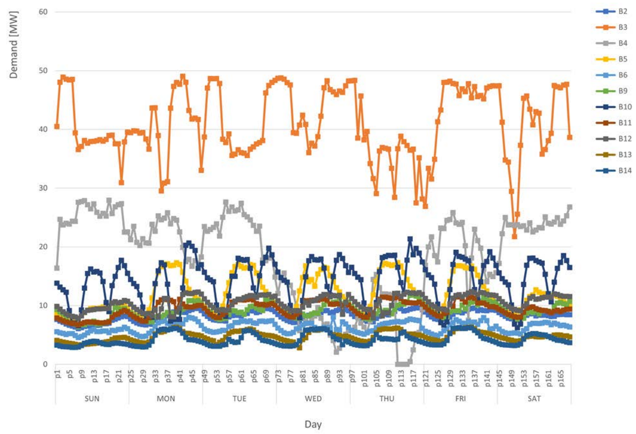

FIGURE 17. Parameter of total demand load per bus scaled to 35%.

TABLE 14. Data input parameters of highest arithmetic mean per-hourly block.

DAY	BUS										
	2	3	4	5	6	9	10	11	12	13	14
Sun	1	0	2	1	1	1	1	1	1	1	1
Mon	1	1	2	2	1	1	1	2	1	2	2
Tue	1	0	2	2	1	1	1	2	1	2	2
Wed	1	0	0	2	1	1	1	2	1	2	2
Thu	1	0	2	2	1	1	1	2	1	2	2
Fri	1	2	2	2	2	1	1	2	1	2	2
Sat	1	1	1	2	1	1	1	1	1	1	2

D. TEST REGISTERS

In Tables 11–13, the scalars, parameters, and boundaries required to determine the variability conditions are considered in the optimization process to test the functionality of the model.

E. LOAD PROFILES

Demand was selected from the real consumption of commercial measurement systems in the wholesale electricity market of the Dominican Republic. Fig. 17 shows the profiles of the load per bus.

The consumption magnitude was scaled by 35% for its adaptation in the generation-network model of Models 0 and 3. This alteration reduces the magnitude but preserves load variability. Additionally, consumption has been diversified to study the behavior of residential, industrial, and commercial users [42]. The magnitude of this type of load offers great functional possibilities for a new demand-response service.

When verifying the load curve of consumers, which includes users with typical residential, commercial, and

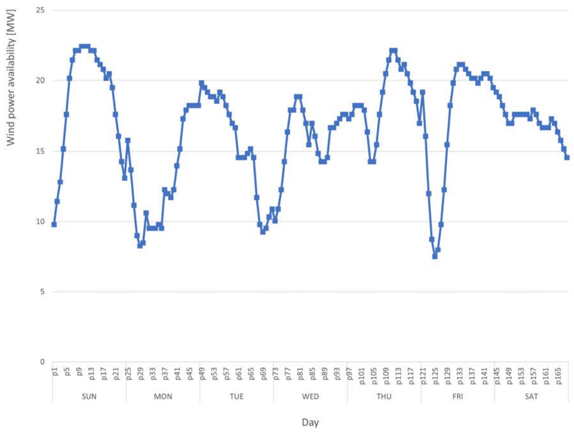

FIGURE 18. Availability of declared Wind energy.

industrial profiles, the arithmetic means of the valley, shoulder, and peak periods are compared to determine the partial load-shifting actions for each day and on each bus, depending on the statistic of the highest magnitude. This task was preprocessed outside the model and entered as an input parameter. The input data are presented in Table 14.

Note: The number indicates the shifting action, according to the scheduling criteria of the operation. In this case, 0 represents no action, 1 shifts the load from peak to valley periods, and 2 from shoulder to valley periods.

F. AVAILABILITY OF DECLARED WIND ENERGY

The records provided by the forecasting service to the system operator were considered, as shown in Fig. 18, to preserve the same variability behavior in the model without degrading the error metrics of the production estimate of the wind power, which for the baseline represents a penetration of 12% of the total demand in the coordination horizon.

ACKNOWLEDGMENT

The authors would like to acknowledge Organismo Coordinador del Sistema Eléctrico Nacional Interconectado (OC). This nonprofit organization plays the role of the operator of the wholesale electricity market in the Dominican Republic. The OC has provided optimization software tools and invaluable support from specialists to review the proposed methodology and case study results.

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