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Impact of Time-of-Use Demand Response Program on Optimal Operation of Afghanistan Real Power System

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Abstract: Like most developing countries, Afghanistan still employs the traditional philosophy of supplying all its load demands whenever they happen. However, to have a reliable and cost-effective system, the new approach proposes to keep the variations of demand at the lowest possible level. The power system infrastructure requires massive capital investment; demand response (DR) is one of the economic options for running the system according to the new scheme. DR has become the intention of many researchers in developed countries. However, very limited works have investigated the employment of appropriate DR programs for developing nations, particularly considering renewable energy sources (RESs). In this paper, as two-stage programming, the effect of the time-of-use demand response (TOU-DR) program on optimal operation of Afghanistan real power system in the presence of RESs and pumped hydropower storage (PHS) system in the day-ahead power market is analyzed. Using the concept of price elasticity, first, an economic model indicating the behaviour of customers involved in TOU-DR program is developed. A genetic algorithm (GA) coded in MATLAB software is used accordingly to schedule energy and reserve so that the total operation cost of the system is minimized. Two simulation cases are considered to verify the effectiveness of the suggested scheme. The first stage programming approach leads case 2 with TOU-DR program to 35 MW (811 MW − 776 MW), \$16,235 (\$528,825 − \$512,590), and 64 MW reductions in the peak load, customer bill and peak to valley distance, respectively compared to case 1 without TOU-DR program. Also, the simulation results for stage 2 show that by employing the TOU-DR program, the system's total cost can be reduced from \$317,880 to \$302,750, which indicates a significant reduction in thermal units' operation cost, import power tariffs and reserve cost.

Keywords: time-of-use demand response; optimal operation; price elasticity; renewable energy sources; genetic algorithm

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1. Introduction

The availability of energy in a country plays an essential role in building its social-economic development. The index of per capita energy consumption is an indicator used to show the prosperity of a nation. Afghanistan is an energy-rich country but still has an energy crisis. Afghanistan's average annual per capita energy consumption at 149 kWh per person ranks it among the lowest in the world [1]. Afghanistan is a mountainous landlocked country situated in South and Central Asia. It borders Iran in the west, Pakistan in the south and east, Uzbekistan, Turkmenistan and Tajikistan in the north and China in the northeast, as shown in Figure 1 [2]. Afghanistan lies at latitude 33°56′20.8″ N and longitude 67°42′35.8″ E. It has a total land area of 652,237 km^2 and a population of about

32.2 million, with more than 70% living in rural areas [3]. Afghanistan has an arid and semi-arid climate with rugged mountains and some plains in the north and southwest [4].

Figure 1. Map of Afghanistan [2].

Decades of war and instability have restrained the country's development, especially energy infrastructure. In recent years, development progress has been remarkable, but large challenges remain. 23.9% of the nation was unemployed, and 54.5% were below the poverty limit in 2017 [5]. The country is among the poorest in the world; Human Development Index (HDI 2019) ranking is 170 out of 189 countries [6]. The total Gross Domestic Product (GDP) amounted to approximately $19.363 billion in 2018 [7]. Per capita gross national income (GNI), and per capita GDP were $550 and $620, respectively [7,8].

In Afghanistan, electricity makes up a growing portion of the total energy consumption; the grid-connected electricity supply increased from 5% in 2002 to 30% in 2015 [9]. 78% of the total consumed electricity was purchased from neighbour countries (Iran, Turkmenistan, Uzbekistan, Tajikistan), and the remaining 22%, equaling around 1000 GWh, was from its national supply grid [10]. The annual level of power consumption for the entire nation is anticipated to rise from 3700 GWh (2015) to 18,400 GWh (2032) and yearly peak power demand from 750 MW (2015) to 3500 MW (2032), which shows that the country will require around five times more power than was generated in 2015 [9].

The energy infrastructure in Afghanistan is faced with significant challenges of insufficient power generation and a weak transmission network. Figure 2 shows the share of different energy sources in the Afghan power system from April 2015 to March 2016. The total generation was recorded to be 4633 GWh. Imports made up about 78% of the total production. Domestic hydropower and thermal power plants contributed 20.4% and 1.6%, respectively [11,12]. Presently, up to 85% of the country's energy need is covered through the utilization of environmentally damaging sources of energy (biomass), which contributes to deforestation, and has negative health impacts. Since biomass is used for cooking and heating, women and children are more exposed and vulnerable to its effects [13]. Also, traditional biomass is supplemented using diesel generators in off-grid areas to compensate for power outages. Inaccessibility to affordable energy restricts economic, social and educational opportunities, particularly for the poor and those in the countryside. About 81% of the population, with over 97% of the rural people, is estimated to use solid fuels for cooking. This results in Afghanistan being among the top ten countries worst influenced by indoor air contamination [14]. According to the United Nations Environment Program (UNEP) estimation at the current rate of wood consumption and deforestation, Afghanistan's forests will disappear within 30 years [15]. On the other hand, considering the generated energy and accessibility, its cooperation to worldwide CO_2 emissions is negligible.

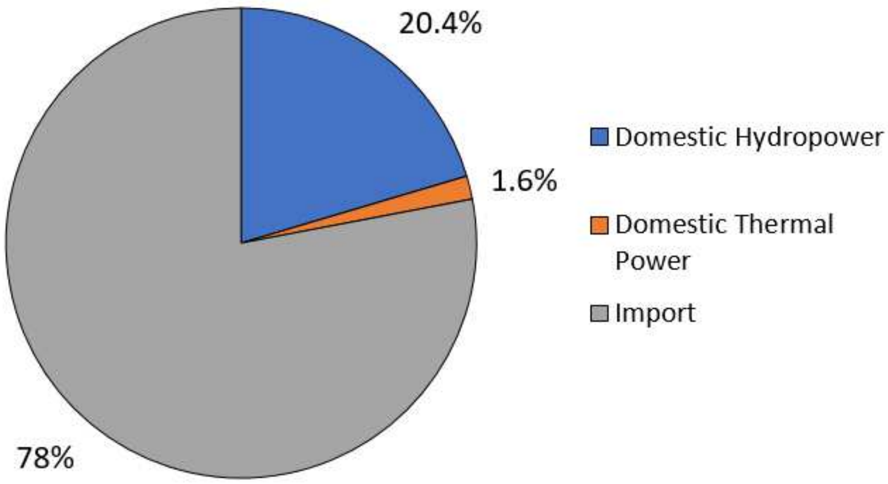

Figure 2. Share of energy sources in grid-connected generation of Afghanistan [11,12].

Fortunately, Afghanistan is endowed with massive renewable energy sources (RESs). According to the preliminary estimation of the National Renewable Energy Laboratory (NREL) of the United States, Afghanistan's technical solar capacity is over 220 GW, and technical wind potential exceeds 66 GW. Therefore, solar and wind resources combination is observed as the best way of mitigating CO_2 emissions in the country, while satisfying the increased power demand. However, as stated in [16], attaining both aims has posed the challenge of huge initial costs of renewable energy technologies for the country. The research work of [16] presented an optimal and economical utilization of RESs for electrification to the northeast area of Afghanistan to meet winter electricity shortages of the area through introducing a hybrid system consisting of photovoltaic (PV) panels, wind turbines (WTs) and battery bank to the grid, Northeast Power System (NEPS) of the country. Ref. [17] mainly focused on optimal operation considering renewable resources of solar, wind and pumped hydropower storage (PHS) system. Wind, solar and PHS were added to the NEPS to schedule units' power generation to minimize the total operation cost of the system. Ref. [18] proposed epsilon multi-objective genetic algorithm (ε-MOGA) as a new multi-objective solution approach for unit commitment (UC) of the NEPS generating units with consideration of solar, wind and PHS. The proposed algorithm and Pareto optimality were used for the system technical and economic optimization to maximize power supply reliability and minimize the total operation cost of thermal units plus aggregate import power tariffs.

In all researches mentioned above, demand-side management was not considered through the execution of the demand response (DR) program for solving techno-economic challenges of the said grid. As per Refs. [19,20], DR programs are useful tools that can improve system reliability, shift peak load demand, reduce transmission system bottlenecks and large price electricity bills by changing or re-managing consumption periods. Moreover, DR programs can lessen the impact of uncertain RESs.

In this paper, the impact of the Time-of-Use demand response (TOU-DR) program on the optimal operation of the NEPS of Afghanistan in the presence of RESs is analyzed. The NEPS supplies electric energy to the northeastern regions and the capital city Kabul from existing hydropower, thermal units with high operation cost and import power from Tajikistan and Uzbekistan with high tariffs. Therefore, two-stage programming, which indicates the effects of the TOU-DR program on load profile and optimal operation of the proposed power system of Afghanistan with the introduction of RESs, is presented. At the first stage, an economic responsive model which indicates the behaviour of customers participating in the TOU-DR program is developed using the concept of price elasticity. In stage 2, a genetic algorithm (GA) is employed to schedule energy and reserve so that the total operation cost of the system is minimized. The effectiveness of the proposed model and methodology is verified through simulations in MATLAB environment under two cases for each stage.

Before describing the methodology, we provide, as below, a brief review of the literature on the important topic of DR.

2. Literature Review

DR programs are short-term activities taken by end-use customers to shift or change their electrical energy consumption from their normal usage periods in response to changes in the cost of electricity over time. Different DR programs are depicted in Figure 3. DR programs are categorised into time-based and incentive-based DR programs, which in turn, time-based programs are subdivided into time-of-use (TOU), real-time-pricing (RTP), and critical-peak-pricing (CPP) programs. In these programs, different energy prices are charged for different periods as per the energy supply cost. Incentive-based DR programs contain direct load control (DLC), emergency demand response program (EDRP), interruptible/curtailable service (I/C), capacity market program (CAP), demand bidding (DB), and ancillary services (A/S) programs. An extensive explanation of DR programmes is available in [21–24].

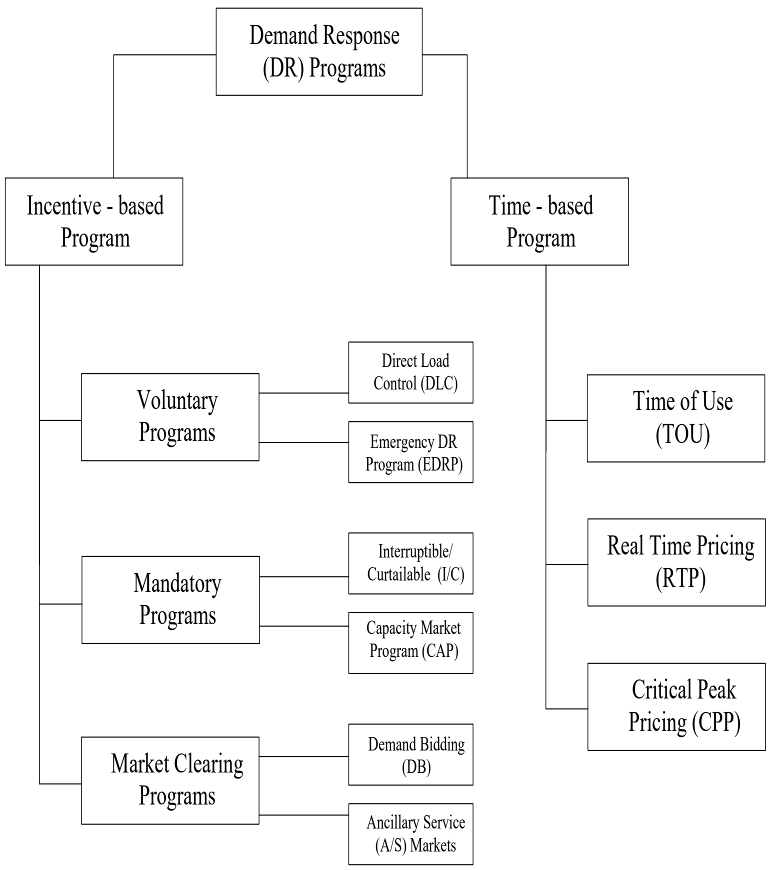

Figure 3. Demand Response programs classifications [21].

The authors in [25] presented a methodology for setting the TOU tariff rates and peak/off-peak rates' interval. The proposed method was based on the contribution of groups of consumers (clustered consumers) to the consumption peak and off-peak to design the rate properly. The proposed methodology considered the customers' type and behaviour and electricity tariff elasticity to incentive off-peak consumption and discourage consumption at peak hours. In Ref. [26], an optimization algorithm was suggested that can be automatically utilized by the electricity suppliers to flatten the electricity consumption curve and identify the TOU tariff that reduces the consumers' electricity payments by means of shifting the consumption of programmable appliances (both interruptible and non-interruptible) from peak hours to off-peak hours. Refs. [27–29] have developed linear economic models of DR programs. In these models, it was adopted that load is changing linearly with regard to elasticity. The Authors in [30] analyzed the behaviour of different nonlinear models of price responsive demands for time-based DR programs versus the linear economic models. It was indicated that both models (linear and nonlinear) have the same performance for small elasticities and price deviations. However, when elasticities and energy prices rise, their behaviour's difference becomes more. Also, they showed that power structure nonlinear models have the most accurate behaviour. The authors in [31] investigated the impact of employing EDRP in the generation scheduling problem by taking the incentive value as the decision variable. It was shown that the incentive value is increased with more customers taking part in the program. Also, operating EDRP for different incentive values and customers' attending levels was analyzed. In [32], the authors proposed a model for the implementation of EDRP and Interruptible load contracts (ILC) in the UC program. It was indicated that EDRP leads to load factor (LF) improvement, and compare to ILC programs, EDRP results in a more decrease in the total costs, whereas its decrease rate of peak value is the same as ILC. A model for deciding the optimum TOU rates based on the grid reliability index is proposed in [33]. In the mentioned research, the effects of the model on system load demand were investigated. Also, the influence of the reliability index on load factor was analyzed. In Ref. [34], critical peak pricing with load control (CPPLC) was analyzed in a multi-objective UC optimization problem. In that study, UC was implemented to schedule the on/off states of generators as well as to specify load demand and price deviations accomplished by the CPPLC program.

The paper under study presents a two-stage programming to show the effects of the TOU-DR program on load shape and optimal operation of Afghanistan's real power system of NEPS with the introduction of solar, wind and PHS system. In the first stage programming, an economic model of the mentioned DR program is developed and is applied to the real load profile of NEPS. And in the second phase, a GA is used to schedule energy and reserve to minimize the total operation cost of the suggested system.

This research paper aims to present the following major contributions:

- Investigating the influences of the TOU-DR program on the optimal operation of a large practical power system from the economic and reliability points of view, which are vital issues for Afghanistan.
- Applying a novel two-stage programming on the proposed power system and simulating each stage programming with two cases.
- Making a complete and detailed analysis for the two cases to show the effectiveness and robustness of the proposed control scheme.
- Aiming to attract the attention of policymakers, energy planners, and designers to consider and apply DR programs in Afghanistan's energy mix.

The rest of the study is managed as follows: Section 3 presents the methodology in details. Section 4 explains the binary-Real Coded GA. Section 5 is devoted for simulation test case. Simulation results for stage 1 and stage 2 are presented in Sections 6 and 7, respectively. Section 8 analyze the results, and finally, Section 9 concludes the research work.

3. Methodology

3.1. Stage 1: Modeling of TOU-DR Program

TOU program is the most prevalent DR option in which the electric energy cost changes over different time intervals based on the electricity supply cost. For instance, expensive for peak hours, moderate for off-peak and cheap for valley periods. In TOU program, there isn't any incentive or penalty for participating customers. To investigate the influence of TOU-DR program on the proposed system load curve and power market characteristics, an economic load model based on price elasticity of demand is necessary.

Elasticities are known as the sensitivity of demands with respect to prices [35].

$$E(h,h) = \frac{\partial LD(h)}{LD(h)} \div \frac{\partial p(h)}{p_0(h)} \tag{1}$$

In which $E(h,h)$ is the elasticity of demand of hth period versus hth period, $LD(h)$ = initial load demand at time h, $p_0(h)$ = initial electricity price at hour h.

As aforementioned, in TOU-DR programs, the electricity prices vary for different periods; therefore, some loads can not move from one time interval to another (only can be "on" or "off") and have sensitivity only in a single time-interval with negative values (self elasticity). Some consumption could be shifted from one period to another which is called multi period sensitivity and has positive values (cross elasticity) [29]:

$$\begin{cases} E(h,h) \leq 0 & if \quad h = k \\ E(h,k) \geq 0 & if \quad h \neq k \end{cases} \tag{2}$$

As per modeling of load in single period, the customer alters his load demand from $LD(h)$ to $LD_{DR}(h)$ to obtain the maximum benefit:

$$LD_{DR}(h) = LD(h) + \Delta LD(h) \tag{3}$$

If the customer's income from the use of $LD_{DR}(h)$ of electric energy during hth hour is $I(LD_{DR}(h))$, then the customer benefit $B(LD_{DR}(h))$ for the same time is as follows:

$$B(LD_{DR}(h)) = I(LD_{DR}(h)) - LD_{DR}(h) \cdot p(h) \tag{4}$$

As per the basic optimization techniques, in order to maximize the user benefit, Equation (5) is equated to zero:

$$\frac{\partial B(LD_{DR}(h))}{\partial LD_{DR}(h)} = \frac{\partial I(LD_{DR}(h))}{\partial LD_{DR}(h)} - p(h) = 0 \tag{5}$$

$$\frac{\partial I(LD_{DR}(h))}{\partial LD_{DR}(h)} = p(h) \tag{6}$$

The benefit function is the quadratic benefit function [29]:

$$\begin{aligned} I(LD_{DR}(h)) = I_0(h) + p_0(h)\left[LD_{DR}(h) - LD(h)\right] \times \\ \left\{1 + \frac{LD_{DR}(h) - LD(h)}{2E(h,h) \cdot LD(h)}\right\} \end{aligned} \tag{7}$$

Differentiating Equation (7) and solving for $\frac{\partial I(LD_{DR}(h))}{\partial LD_{DR}(h)}$ and substitute into Equation (6) results:

$$p(h) = p_0(h) \cdot \left\{1 + \frac{LD_{DR}(h) - LD(h)}{E(h,h) \cdot LD(h)}\right\} \tag{8}$$

As a result, customer's consumption after employing single period elastic model is:

$$LD_{DR}(h) = LD(h)\left\{1 + E(h,h) \cdot \frac{\left[p(h) - p_0(h)\right]}{p_0(h)}\right\} \tag{9}$$

For the multi period, the cross elasticity $E(h,k)$ is computed for the hth time interval with regard to all other periods as follows:

$$E(h,k) = \frac{\partial LD(h)}{LD(h)} / \frac{\partial p(k)}{p_0(k)} \tag{10}$$

Implying the linear relationship between prices and demands:

$$LD_{DR}(h) = LD(h)\left\{1 + \sum_{\substack{h=1\\h\neq k}}^{N_H} E(h,k) \cdot \frac{[p(k) - p_0(k)]}{p_0(k)}\right\} \tag{11}$$

As power demand consists of both periods loads, therefore by combining Equations (9) and (11), the responsive load economic model is obtained as Equation (12):

$$LD_{DR}(h) = LD(h)\left\{1 + E(h,h) \cdot \frac{p(h) - p_0(h)}{p_0(h)} + \sum_{\substack{h=1\\h\neq k}}^{N_H} E(h,k) \cdot \frac{p(k) - p_0(k)}{p_0(k)}\right\} \tag{12}$$

Equation (12) depicts the customer's consumption for obtaining maximum gains in a 24 h when taking part in the TOU-DR program.

3.2. Stage 2: Power System Formulation and Optimization

Before defining the objective function it is worthy to have a brief introduction of the NEPS of Afghanistan.

3.2.1. Afghanistan Power System and Its Power Trade with Neighboring Countries

The existing power system of Afghanistan is operating in separate areas depending on the source of generation and impacts. As depicted in Figure 4, currently, there are within Afghanistan three distinct geographically separate transmission networks:

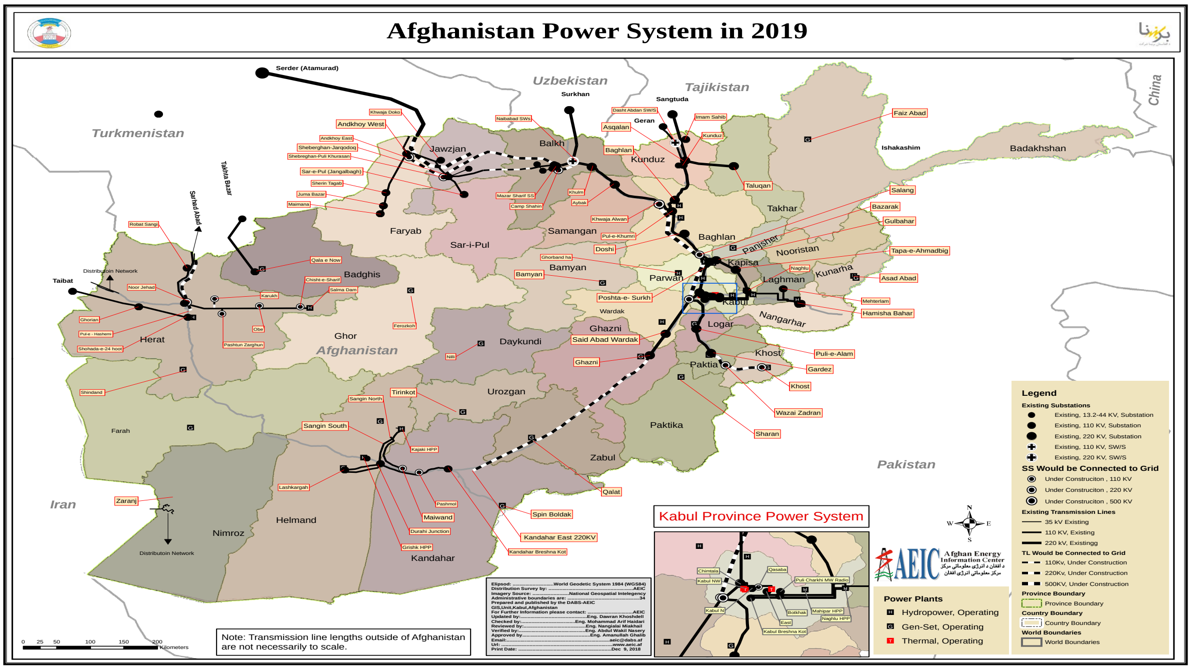

Figure 4. Existing Afghan Power System [36].

The Northeast Power system (NEPS): The biggest power network of Afghanistan supplied by its own hydropower and diesel plants and purchase power from Tajikistan and Uzbekistan.

The Southeast Power System (SEPS): Currently fed by available hydropower units of the country.

Herat: Presently covered by imports from Iran and Turkmenistan.

In addition, several towns have their own diesel plants and distribution [37,38].

3.2.2. Objective Function

In stage 2 of this research work, the objective is to minimize the total operation cost of the NEPS system consists of purchasing energy cost from the neighboring countries plus fuel cost, start-up cost and providing reserve capacity cost of thermal generators, mathematically modeled as below:

$$Min \sum_{h=1}^{N_H} \left[\sum_{z=1}^{N_Z} c(z) \times PF(z,h) + \sum_{j=1}^{N_TG} \{CE_{TG}(j,h) + CS_{TG}(j,h) + CR_{TG}(j,h)\} \right] \tag{13}$$

where:

h is the time period , $h = 1, \ldots, N_H$

z indicates the electricity exporting countries, $z = 1, \ldots, N_Z$;

$c(z)$ depicts the exporting country z selling price;

$PF(z,h)$ shows the power flow of zth country to Afghanistan at time h;

j depicts thermal generators, $j = 1, \ldots, N_{TG}$;

$CE_{TG}(j,h)$ is the cost function for electric energy generation of jth thermal generator at time h;

$CS_{TG}(j,h)$ depicts jth thermal generator's start up cost at hour h;

$CR_{TG}(j,h)$ is the reserve deploying cost from jth thermal generator;

3.2.3. Constraints

The proposed power system has to be scheduled and operated based on the following constraints:

Power Balance Constraint

The total produced electricity must be equal to the system power demand in each hour.

$$\begin{aligned} LD(h) = \sum_{j=1}^{N_{TG}} P_{TG}(j,h) + \sum_{z=1}^{N_Z} PF(z,h) + \sum_{i=1}^{N_i} P_H(i,h) + P_{PV}(h) \\ + P_W(h) + P_{PHS}(h) \times \eta_{PHS} - P_{PHS}(h) \end{aligned} \tag{14}$$

where

$LD(h)$ is load demand of the network at hour h.

$P_{TG}(j,h)$ is jth thermal unit's power production at time h;

i depicts hydropower units, $i = 1, \ldots, N_i$;

$P_H(i,h)$ is electric power generation of ith hydropower plant at hour h;

$P_{PV}(h)$ is power production of PV at hour h;

$P_W(h)$ is power generation of wind turbine at period h;

$P_{PHS}(h)$ is electric energy supply of PHS plant;

η_{PHS} is the overall efficiency of PHS plant.

Thermal Units Constraints

The fuel cost quadratic equation of a thermal generator is mathematically expressed as a function of its power generation as follows:

$$CE_{TG}(j,h) = a_j \times s(j,h) + b_j \times P_{TG}(j,h) + c_j \times P_{TG}^2(j,h) \ \ \forall j,h \tag{15}$$

where a_j, b_j, and c_j are the cost function coefficients of thermal generator j and $s(j,h)$ is the start-up/shut down [0, 1] states of jth thermal unit at time h.

The start up cost of thermal generator is computed by the following equation:

$$CS_{TG}(j,h) = SUC(h) \times (s(j,h) - s(j,h-1)) \quad \forall j,h \tag{16}$$

The cost of deploying reserves from thermal units is equal to KR_{DG}% of its largest marginal cost of operation, mathematically expressed as below:

$$CR_{TG}(j,h) = KR_{TG} \times (b_j + 2 \times c_j \times P_{TG,max}(j,h)) \\ \times R_{TG}(j,h) \quad \forall j,h \tag{17}$$

In the above equation, $P_{TG,max}(j,h)$ is the maximum generation limit of jth thermal unit and $R_{TG}(j,h)$ is the scheduled reserve capacity of jth thermal unit at hour h. The following equations ensure that the electric energy supply of thermal generators is limited within their minimum and maximum level:

$$P_{TG,min}(j) \times s(j,h) \leq P_{TG}(j,h) \leq P_{TG,max}(j) \times s(j,h) \quad \forall j,h \tag{18}$$

$$P_{TG}(j,h) + R_{TG}(j,h) \leq P_{TG,max}(j) \times s(j,h) \quad \forall j,h \tag{19}$$

where $P_{TG,min}(j)$ is the minimum power limit of thermal units.

Moreover, after committing a unit, it should be remained online for a prespecified period before it can be offline. In addition, once a thermal unit is decommitted, a predefined time interval is required before it can be committed. These constraints are modeled as bellow:

$$[T_{on}(j,h) - MU(j)][s(j,h-1) - s(j,h)] \geq 0 \tag{20}$$

$$[T_{off}(j,h) - MD(j)][s(j,h) - s(j,h-1)] \geq 0 \tag{21}$$

where:

$$T_{on}(j,h) = [T_{on}(j,h-1) + 1]s(j,h) \tag{22}$$

$$T_{off}(j,h) = (T_{off}[(j,h-1) + 1][1 - s(j,h)] \tag{23}$$

$T_{on}(j,h)$: The total uptime of jth unit;
$MU(j)$: The minimum uptime of unit j.
$MD(j)$: The minimum downtime of jth generator;
$T_{off}(j,h)$ is the period of jth unit being continuously off;

Electricity Trading Constraint

Power purchasing of Afghanistan from zth country is constrained by the lower and higher power export limit of the zth country.

$$PF_{min}(z) \leq PF(z,h) \leq PF_{max}(z) \tag{24}$$

PV Panels Output Power

The electric power generated by a PV array (P_{PV}) is obtained based on the bellow equation:

$$P_{PV}(h) = \eta_{PV} \cdot A_{PV} \cdot S(h) \tag{25}$$

In which η_{PV} indicates PV array efficiency, A_{PV} is the total area taken by PV array in m^2 and $S(h)$ denotes the hourly solar insulation in $\mathrm{MW/m^2}$.

Wind Generator Output Power

The power produced by wind turbines is modeled using the following expression:

$$P_W(h) = \begin{cases} 0 & v(h) \leq V_{ci} \quad or \quad v(h) \geq V_{co} \\ P_r \frac{v^3(h) - V_{ci}^3}{V_r^3 - V_{ci}^3} & V_{ci} \leq v(h) \leq V_r \\ P_r & V_r < v(h) < V_{co} \end{cases} \tag{26}$$

where P_r is the rated output power of wind turbine, V_{ci}, V_r, V_{co} are the rated, cut-in, and cut-off speed of wind generator, respectively.

Pumped Hydropower Storage (PHS) Model

The PHS system has been considered in two different modes including pumping and generating. In pumping mode, PHS operates as a load and absorbs power from the power system. In generating mode, PHS performs as a power generating and supplies the absorbed power. The following equations are used to model the PHS:

$$b_p(h) + b_g(h) \leq 1; \quad b_p,\ b_g \in (0,1),\ \ \forall h \tag{27}$$

$$SOC(h) = SOC(h-1) + P_{PHS}(h) \times \eta_{PHS} - P_{PSH}(h) \tag{28}$$

$$SOC_{min} \leq SOC(h) \leq SOC_{max} \tag{29}$$

$$P_{PHS,min} \leq P_{PHS}(h) \leq P_{PHS,max} \tag{30}$$

The flowchart of the methodology described in details is shown in Figure 5.

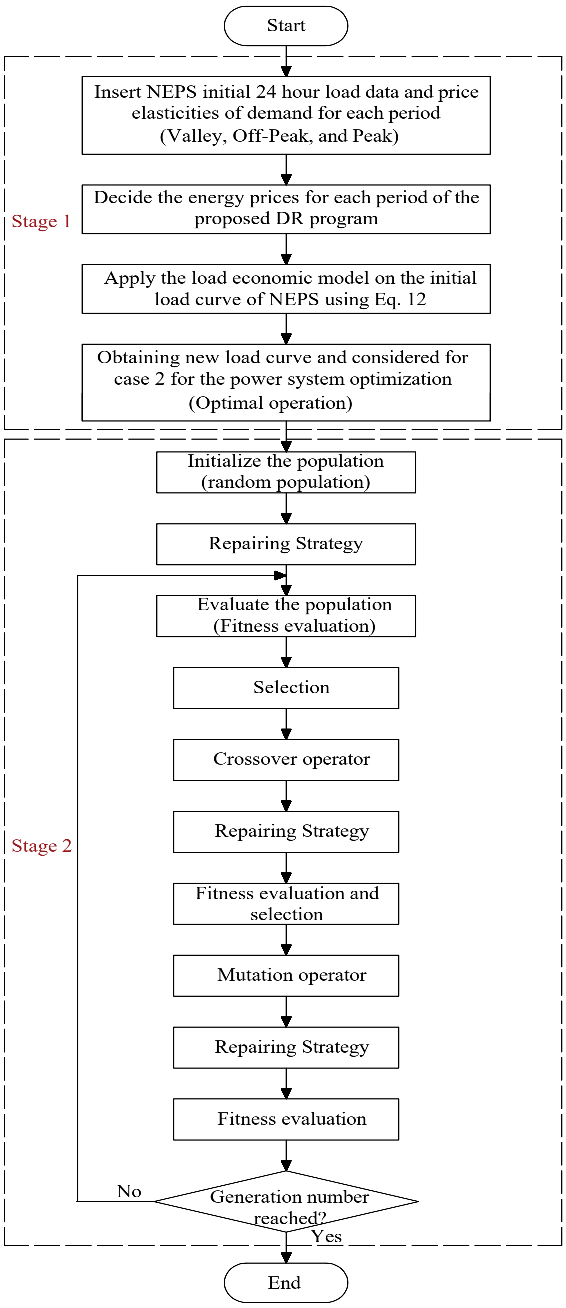

Figure 5. Flowchart of the proposed methodology used in this study.

4. Binary-Real Coded GA

In this paper, the second stage programming is optimized using the binary-real GA coded in MATLAB software. The binary-coded GA determines thermal units' on/off states, and the real-coded GA obtains the power dispatch of thermal generating units, optimal power imports and reserve capacities. In the GA solution method, the populations are first randomly initialized within their predefined domain. Then, the repairing strategies considered in [39–41] are applied not only after the initialization, but also after crossover and mutation operations.

The suggested algorithm has been run 10 times for case 1 and case 2, and the best results are presented. The computation time of the proposed GA algorithm is about 3 min, which is excellent and meets the real-time control requirement. In the proposed GA, the parameters listed in Table 1 are considered. The population size and the maximum numbers of iterations are 200 and 500, respectively. The tournament selection technique with 2-tournament size, two-point crossover operation and mutation are employed for optimization. The crossover and mutation probabilities are 0.7 and 0.3, respectively.

Table 1. Parameters of the proposed GA.

Parameter	Numerical Value
Population size	200
Maximum iteration	500
Crossover Probability	0.7
Mutation Probability	0.3

5. Simulation Test Case

The simplified single line diagram of the power network is shown in Figure 6 which is the NEPS of Afghanistan with adding PV, wind and PHS power generations each with maximum 300 MW, 200 MW, and 300 MWh capacities, respectively. The initial state of charge (*SOC*) of the upper reservoir of PHS is considered to be 20% of its aggregate capacity. The maximum pumping and generating power for each hour is 60 MW. The minimum and maximum limits of the *SOC* are 20% and 80% of the total capacity, respectively, and its overall efficiency (η_{PSH}) is 70%. The parameters for thermal generators are shown in Table 2, and Table 3 indicates import power data. The proposed network also contains 100 MW, 66 MW and 22 MW hydropower units. The hourly load demand is shown Figure 7 which is divided into three different time intervals. The wind and PV output power obtained from the models (Equations (25) and (26)) are illustrated in Figure 8 and Figure 9, respectively.

Table 2. Thermal generators data [42,43].

	TG1	TG2	TG3
$P_{TG,max}$ [MW]	105	22	23
$P_{TG,min}$ [MW]	15	5	5
a [\$/h]	680	660	665
b [\$/MWh]	16.5	25.92	27.27
c [\$/MW^{2}h]	0.00211	0.00413	0.00222
MU [h]	4	1	1
MD [h]	4	1	1
SUC [\$]	560	30	30
$T(0)$ [h]	4	1	−1

Table 3. Import powers parameters [42,43].

Parameters	Tajikistan	Uzbekistan
PF_{max} [MW]	300	300
PF_{min} [MW]	0	0
c (\$/MWh)	20	60

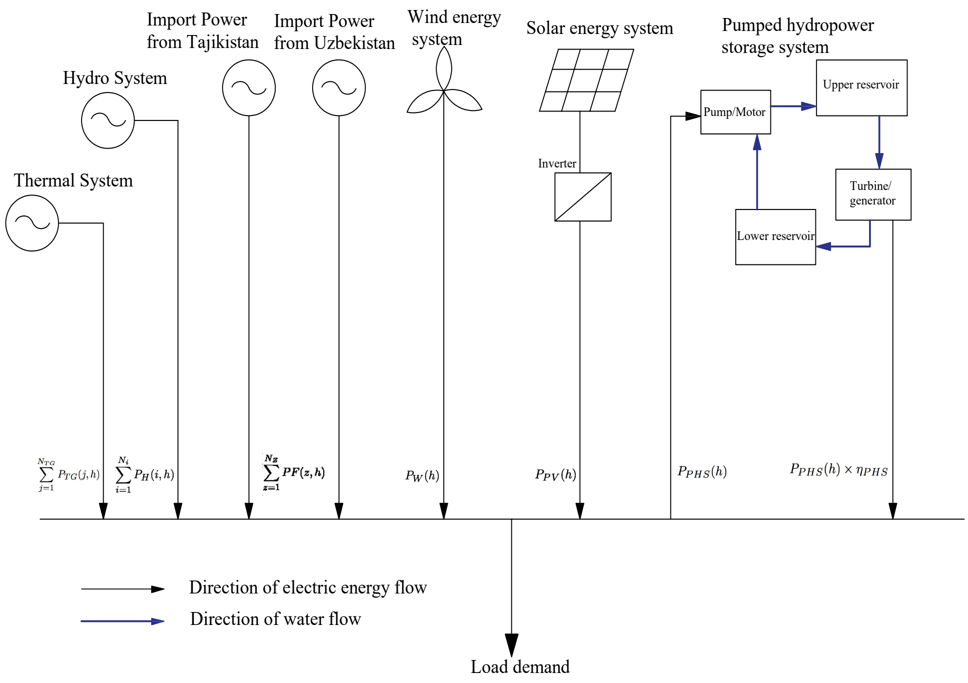

Figure 6. The generation system under study.

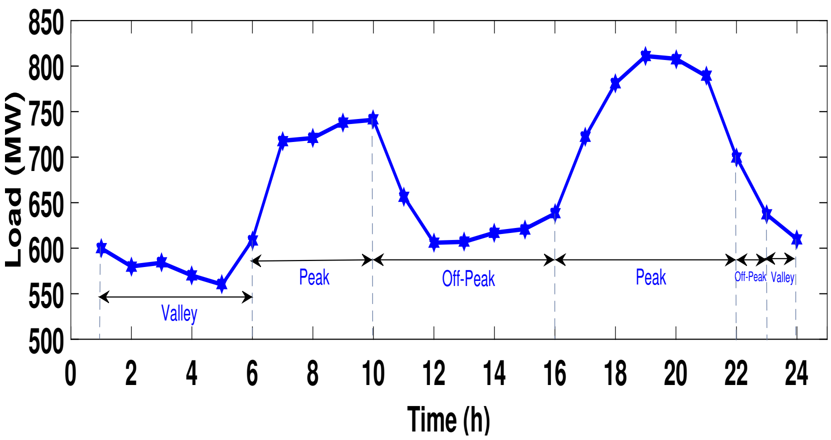

Figure 7. Load demand curve of NEPS [17].

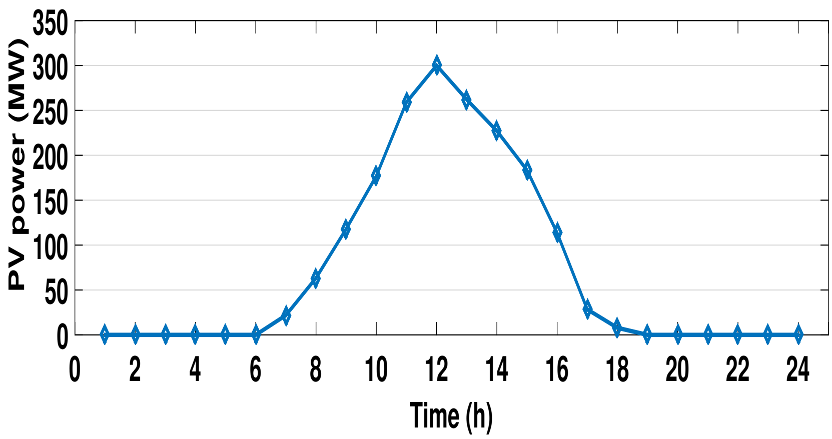

Figure 8. PV output power.

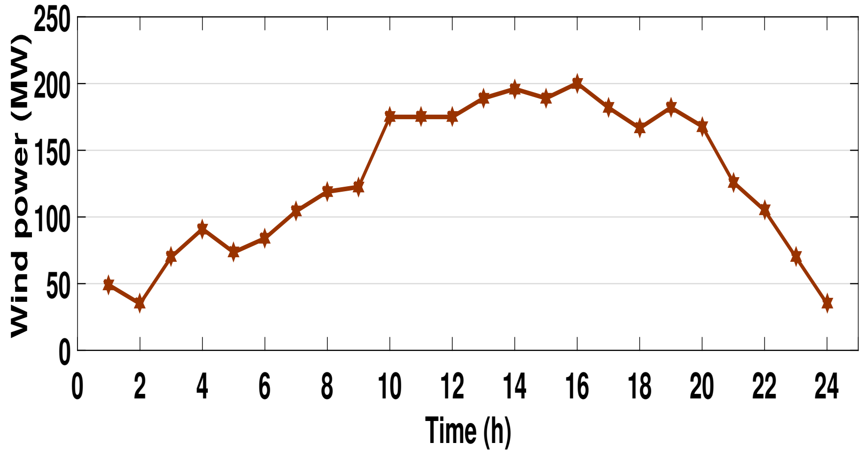

Figure 9. Wind output power.

The potential of the TOU-DR program is assumed to be 10%, which means, participating customer's total signing contract in the TOU program is 10% of the total demand. The price elasticities of the load are indicated in Table 4 and the price of electricity has been depicted in Figure 10.

Table 4. Self and cross elasticities [29].

Hour	(24–6)	(11–16, 23–24)	(7–10, 17–22)
(24–6)	−0.1	0.01	0.012
(11–16, 23–24)	0.01	−0.1	0.016
(7–10, 17–22)	0.012	0.016	−0.1

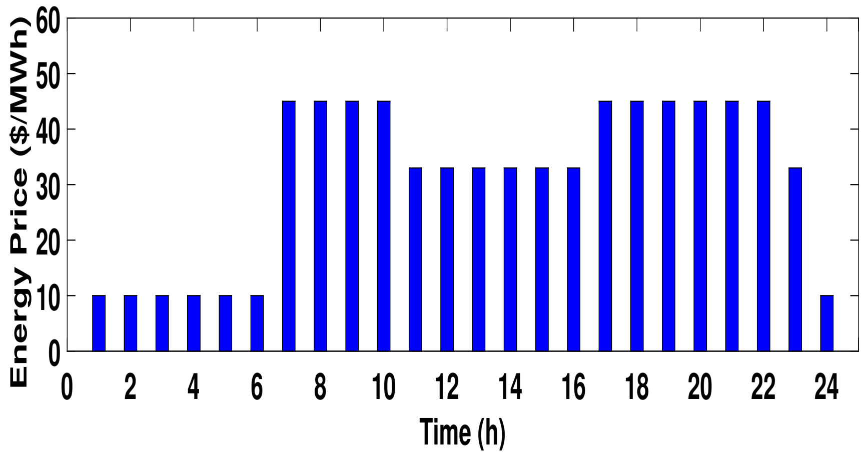

Figure 10. Energy prices for the proposed DR program.

6. Results of TOU-DR Program Implementation and Analysis (Stage 1)

Two cases have been considered as shown in Table 5. The impact of TOU-DR program on load profile characteristics is discussed as follows:

Case 1: This case is the base case with the real load curve indicated in Figure 7 (without TOU-DR program) to compare the results of case 2 (with TOU-DR program) with it. As depicted in Table 5, in this case, the electrical energy consumption is 16,025 MWh, the customer bill, peak load, and load factor are $528,825, 811 MW and 82.33%, respectively. Moreover, the peak to valley distance is 251 MW.

Case 2: In this case, the parameters shown in Table 5 are presented after applying the final model (Equation (12)) on the initial load curve of Figure 7. As illustrated in Table 5, compared to the base case, electrical energy consumption is reduced to 15,930 MWh (0.59%).

Also, the peak load, customer bill and peak to valley distance are decreased by 35 MW (4.31%), $16,235 (1%) and 64 MW respectively and the load factor is increased to 85.53% as shown in Figure 11. As a result, the proposed responsive load economic model leads case 2 with TOU-DR program to $16,235 ($528,825 − $512,590), and 64 MW reductions in customer bill and peak to valley distance, respectively compared to case 1 without TOU-DR program. Additionally, the peak load which happens for every few hours and needs power plants to be built for those limited hours is also reduced from 811 MW to 776 MW. The other important factor of load factor which also has an effective role in economics of power systems is increased from 82.33% to 85.53%.

Table 5. Load profile characteristics and analysis.

Parameters	Case 1 (without TOU-DR)	Case 2 (with TOU-DR)
Energy Consumption (MWh)	16,025	15,930
Customer bill ($)	528,825	512,590
Peak Load (MW)	811	776
Load Factor (%)	82.33	85.53
Customer benefit ($)	0	16,235
Energy reduction (%)	0	0.59
Peak reduction (%)	0	4.31
Peak to valley distance (MW)	251	187

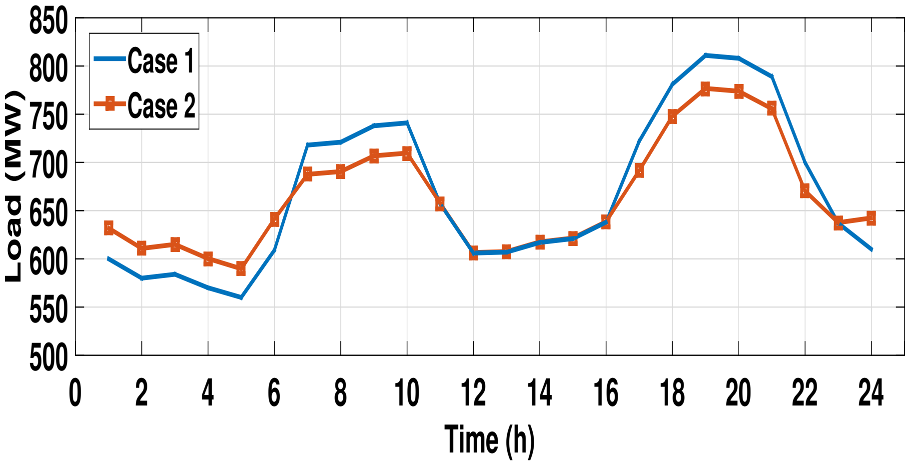

Figure 11. Effect of TOU-DR program on the initial load profile.

7. Results of Power System Optimization (Stage 2)

In order to evaluate the effectiveness of the TOU-DR program from the perspective of energy and reserve scheduling, the fitness function (Equation (13)) subject to constraints (Equations (14)–(24)) is optimized using the proposed GA method before and after employing TOU-DR program, elaborated as case 1 and case 2, respectively.

Case 1: The effect of not integrating the TOU-DR program into the suggested power system when dealing with day-ahead scheduling is investigated. The scheduled energy is indicated in Figure 12. As can be observed, during hours 1:00–9:00 and 17:00–24:00 with relatively low renewable energy production (PV and wind), the needed energy is significantly imported from Tajikistan and Uzbekistan. On the other hand, the imported power from the two neighboring countries decreases as the produced power from PV and wind increases between 10:00 and 16:00. Moreover, thermal units are mainly dispatched at peak hours due to their high operation cost. Figure 13 depicts the scheduled reserve capacity provided by thermal generators and import power. It can be seen that due to low tariff and much availability of import power, most of the scheduled reserve is covered by import power.

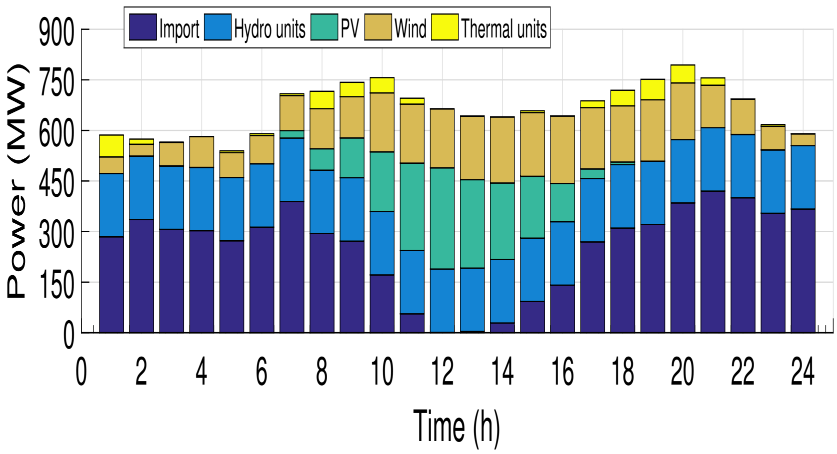

Figure 12. Scheduled power in case 1.

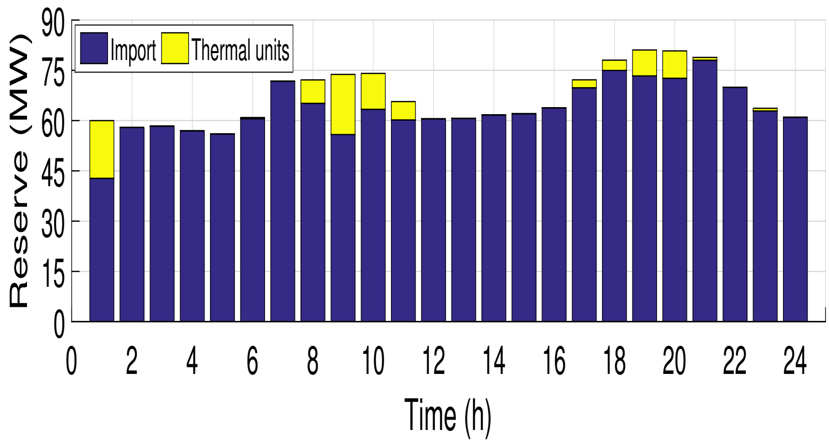

Figure 13. Scheduled reserve power in case 1.

Figure 14, illustrates the output power and storage level of the PHS. As expected, the PHS uses excess generated power at some off-peak hours to pump the water from the lower reservoir to the upper reservoir. And then releases the stored water to flow back to the lower reservoir to generate power through a turbine/generator unit to cover the shortage. Therefore, pumping/generating scheduling of the PHS decreases the import power tariff and the thermal units operation cost. The total cost of the proposed system as well as thermal units' operation cost, import power tariffs and reserve cost are \$317,880, \$23,059, \$238,970 and \$55,850, respectively.

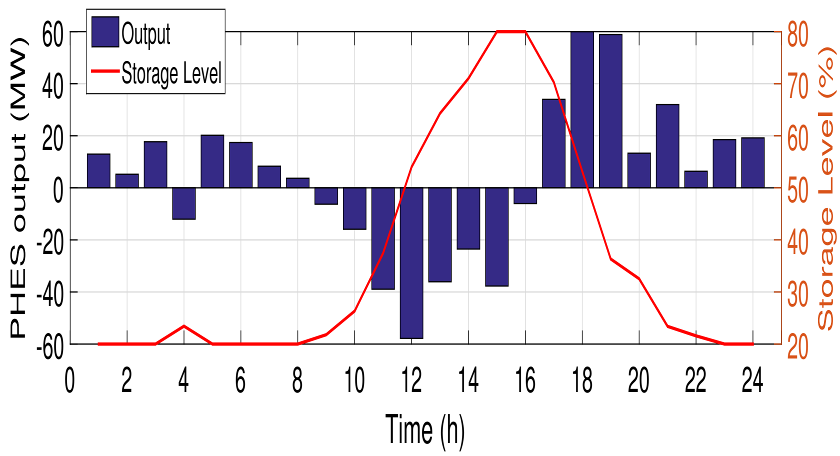

Figure 14. PHS output and storage level.

Case 2: The optimal operation of the proposed power system with the TOU-DR program participation is presented. Comparing the results in Table 6 shows that with the TOU-DR program consideration, the total cost of the system as well as thermal units operation cost, import power tariffs and reserve cost are reduced to $302,750, $20,024, $228,090 and $54,644 respectively, since the energy and reserve capacity provided by thermal units and import power are decreased (Figures 15 and 16) due to customer's reduction of consumption during the hours with high energy prices in order to save energy. Moreover, as load factor increased in this case, therefore compared to case 1 (Figure 17), it requires less start-up cost for thermal units (Figure 18).

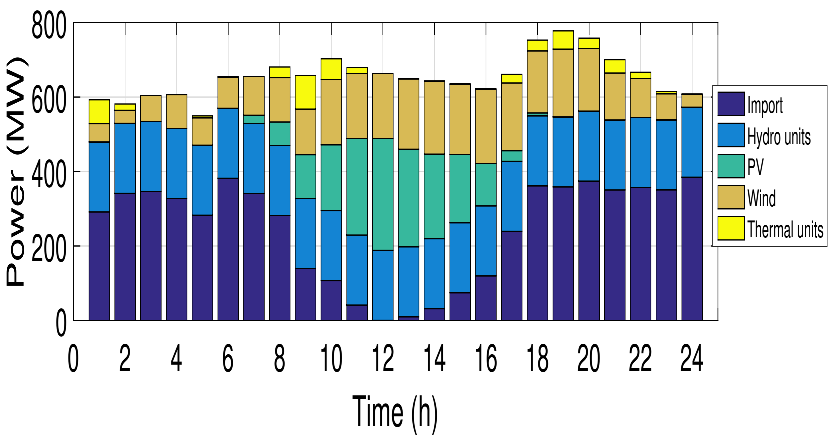

Figure 15. Scheduled power in case 2.

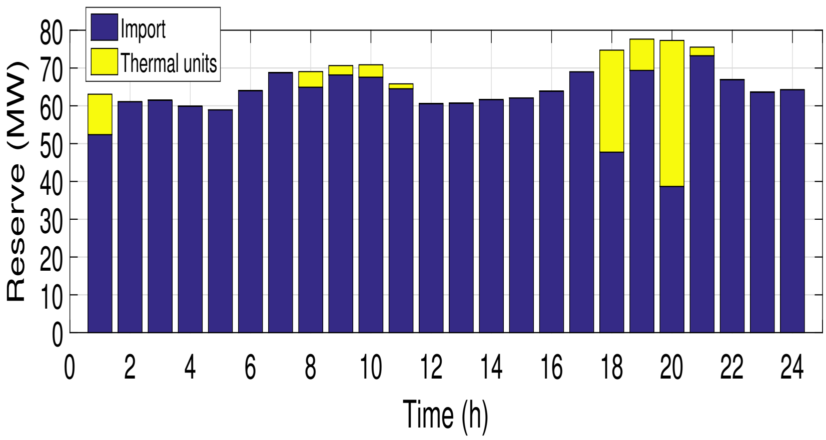

Figure 16. Scheduled reserve power in case 2.

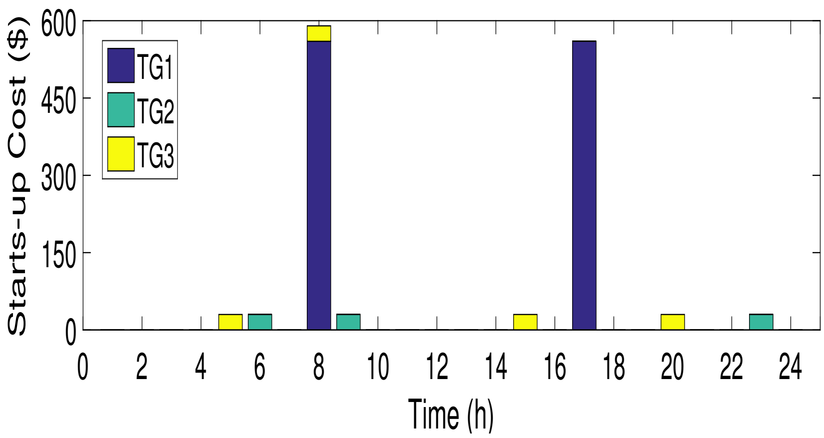

Figure 17. Starts-up cost of thermal units in case 1

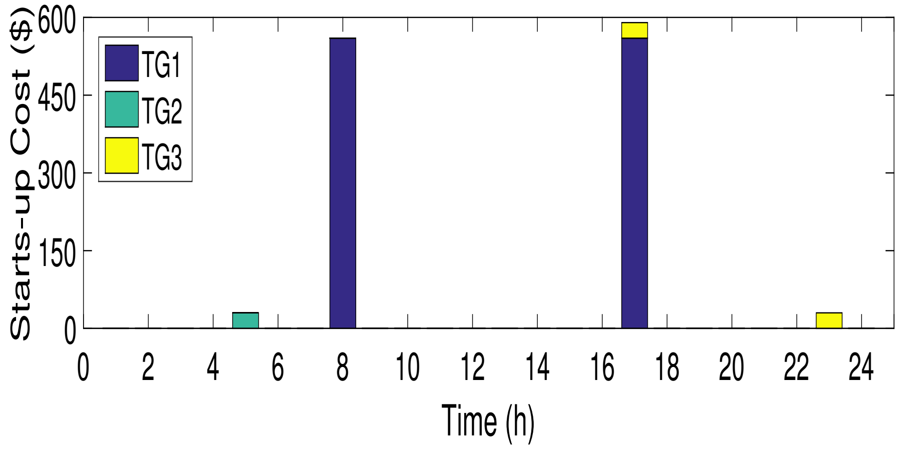

Figure 18. Starts-up cost of thermal units in case 2.

Table 6. Optimization costs comparison.

Parameters	Case 1 (without TOU-DR)	Case 2 (with TOU-DR)
Total cost ($)	317,880	302,750
Thermal units operation cost ($)	23,059	20,024
Import power tariffs ($)	238,970	228,090
Reserve cost ($)	55,850	54,644

8. Results Analysis

This section presents a detailed discussion on the simulation results for both stage 1 and stage 2 from economical and reliability points of view. For stage 1, we have investigated the influences of TOU-DR program on load demand characteristics of the proposed practical power system of Afghanistan considering case 1 without TOU-DR program participation and taking the initial load curve and case 2 with taking into account the new load curve after getting through implementation of the TOU-DR program. The results indicated that with TOU-DR program the total electric energy consumption decreased from 16,025 MWh to 15,903 MWh. The peak load which happens for every few hours and needs power plants to be built for those limited hours is also reduced from 811 MW to 776 MW. The other important factor of load factor which also has an effective role in economics of power systems is increased from 82.33% to 85.53%. Finally, the obtained results also have benefits for customers with bill paying of $512,590 instead of $ 528,825.

For stage 2, the same real power system which is the largest power system of the country is optimized using the proposed control scheme. To show the effectiveness of the suggested control approach two cases have been considered. Case 1 is optimized without the employment of TOU-DR program and case 2 is simulated after the execution of the TOU-DR program. It was shown that with integrating the TOU-DR program in the NEPS of the country when scheduling the day-ahead operation, the total cost can be reduced from $317,880 to $302,750 which indicates a significant reduction in total operation cost of the thermal generators, import power tariffs and reserve cost. The reason behind this cost reduction is the customers' participation in the TOU-DR program resulting in reducing energy consumption during the periods with high energy prices. In addition, there is another essential point of load factor which increased in case 2 after introducing the TOU-DR program which reduces the start-up cost of thermal units.

9. Conclusions

This paper proposes a new two-stage programming to show the effect of the TOU-DR program on optimal operation of the NEPS of Afghanistan considering PV, wind and PHS systems. In the first stage, based on price elasticity, an economic load demand model that shows the behaviour of customers participating in the TOU-DR program is developed and applied to the actual load curve of the NEPS of Afghanistan. In the second, the binary-real GA coded in MATLAB software is employed to minimize the system's total cost. Two case studies are implemented to evaluate the effectiveness of the proposed novel model and methodology. The simulation results for stage 1 indicated that case 1 considered no TOU-DR program; hence the customer bill, peak load, and load factor are $528,825, 811 MW and 82.33%, respectively, and the peak to valley distance is 251 MW. However, for case 2, with customers' participation in the proposed program, the peak load, customer bill, and peak to valley distance are reduced by 35 MW, $16,235 and 64 MW, respectively. The load factor is increased to 85.53%. Also, the simulation results for stage 2 show that by utilizing the TOU-DR program, the system's total cost is decreased from $317,880 to $302,750.

The results indicate that the proposed DR program model can significantly reduce the electrical energy consumption, peak load, customer bill, and peak to valley distance while the load factor and customer benefit are increased. Moreover, the simulation results of the proposed power system optimization reveal that customers' participation in the DR program reduces the system's total cost because of reduced energy and reserve capacity supplied by thermal generators and import power.

This paper does not consider the impact of DR-enabling technology costs such as smart metering systems, sensors, applications, and communication systems in the proposed model and methodology. Therefore, for a future research paper, the effect of these DR-enabling technologies will be included in the model. Also, the uncertainty of PV and wind in the proposed economic model will be integrated.

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Abbreviations

The following abbreviations are used in this manuscript:

A/S	Ancillary Services
DB	Demand Bidding
CAP	Capacity Market Program
CPP	Critical-Peak-Pricing
CPPLC	Critical Peak Load Control
DLC	Direct Load Control
DR	Demand Response
EDRP	Emergency Demand Response Program
GA	Genetic Algorithm
GDP	Gross Domestic Product
GNI	Gross National Income
HDI	Human Development Index
I/C	Interruptible/Curtailable
ILC	Interruptible Load Contract
NEPS	Northeast Power System
NREL	National Renewable Energy Laboratory
PHS	Pumped hydropower storage
PV	Photovoltaic
Ref.	Reference

RESs	Renewable Energy Sources
RTP	Real-Time-Pricing
TOU-DR	Time-of-Use Demand Response
UC	Unit Commitment
UNEP	United Nations Environment Program
WTs	Wind Turbines
Symbol	**Description**
h	Time period, $h = 1, \ldots, N_H$
i	Hydropower units, $i = 1, \ldots, N_i$
j	Thermal generators, $j = 1, \ldots, N_{TG}$
z	Electricity exporting countries, $z = 1, \ldots, N_Z$
a_j, b_j, c_j	Cost function coefficients of thermal unit j
A_{PV}	Total area taken by PV array
$b_p(h), b_g(h)$	Binary variables [0,1] for pumping/generating modes of PHS
$B(LD_{DR}(h))$	Customer benefit at hour h
$c(z)$	Exporting country z selling price
$CE_{TG}(j,h)$	Cost function for electric energy generation of jth thermal generator at time h
$CR_{TG}(j,h)$	Reserve deploying cost from jth thermal generator
$CS_{TG}(j,h)$	jth thermal generator's start up cost at hour h
$E(h,h)$	Elasticity of demand of hth period versus hth period
$I(LD_{DR}(h))$	Customer's income from the use of $LD_{DR}(h)$ of electric energy during hth hour
$LD(h)$	Load demand of the network at hour h
$LD_{DR}(h)$	Load demand of the network after employing DR program.
$MU(j)$	Minimum uptime of unit j
$MD(j)$	Minimum downtime of jth generator
$PF(z,h)$	Power flow of zth country to Afghanistan at time h
$PF_{min}(z)$	Minimum power flow of zth country to Afghanistan
$PF_{max}(z)$	Maximum power flow of zth country to Afghanistan
$P_{TG}(j,h)$	jth thermal unit's power production at time h
$P_{TG,max}(j)$	Maximum generation limit of jth thermal unit
$P_{TG,min}(j)$	Minimum generation limit of jth thermal unit
$P_H(j,h)$	Electric power generation of ith hydropower plant at hour h
$P_{PV}(h)$	Power production of PV at hour h
$P_W(h)$	Power generation of wind turbine at period h
$P_{PHS}(h)$	Electric energy supply of PHS plant
$P_{PHS,min}$	Minimum energy supply of PHS plant
$P_{PHS,max}$	Maximum energy supply of PHS plant
P_r	Rated output power of wind turbine
$R_{TG}(j,h)$	Scheduled reserve capacity of jth thermal unit at hour h
$S(h)$	Hourly solar insulation
$SOC(h)$	State of charge of the upper reservoir of PHS
SOC_{min}	Minimum limit of the SOC
SOC_{max}	Maximum limit of the SOC
$s(j,h)$	Start-up/shut down [0,1] states of jth thermal unit at time h
$T_{on}(j,h)$	Total uptime of jth unit
$T_{off}(j,h)$	Period of jth unit being continuously off
v_{ci}	Cut-in speed of wind generator
v_r	Rated speed of wind generator
v_{co}	Cut-off speed of wind generator
$p_0(h)$	Initial electricity price at hour h
η_{PHS}	PHS overall efficiency

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