Expansion Planning of Generation Technologies in Electric Energy Systems Under Water Use Constraints with Renewable Resources

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Abstract

Thermal power generation needs great volumes of water for cooling purposes. A multi-period Low Water Generation Expansion Planning (LW-GEP) model is proposed to plan the future generation mix including type, capacity, time of installation, and proper cooling system of generation technologies to supply the future electric peak loads under the water resource limitations. Different types of generation technologies with conventional and modern cooling systems are considered as expansion candidates in the proposed LW-GEP model. The access of candidate and existing power plants to the water resources are considered. Renewable resources as water smart solutions are integrated in the proposed energy planning model. According to the obtained results, the regional water use constraints impact the generation mix significantly in favor of the dry-cooled and open cycle units. Using the proposed LW-GEP model, the total saving in water consumption for the simulated large scale power system, in regions with water stress and scarcity conditions, reaches to $3.7 \times 10^9\ m^3$, that is approximately equal to the water consumption of a metropolis such as Tehran in three years. Also, it is shown that the integration of renewable resources as water smart solutions results in reduction of expansion planning cost and more water saving.

Keywords:
Energy system planning, generation expansion, water consumption, water withdrawal, cooling systems, renewable resources, optimization.

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Nomenclature

Indices

b	Index for load blocks
i	Index for generating units
k	Index for types of non-renewable units
r/cr	Index for water regions/critical water regions
s	Index for renewable technologies
t	Index for time stages in planning horizon

Sets

Ω_g	All existing and candidate non-renewable units
Ω_g^{ex}	All non-renewable existing units
Ω_g^k	All non-renewable candidate units
Ω_g^{all}	All existing and candidate units
Ω_r	All water regions
Ω_g^r	All non-renewable units in water region r
Ω_g^s	All candidate renewable units
Ω_g^{cr}	All non-renewable units in critical water region cr
Ω_k^{all}	All generation technologies of non-renewable units
Ω_r^{cr}	All water critical regions
Ω_b	All load blocks in each time stage
Ω_t	All time stages in planning horizon

Parameters

cf_i	Capacity Factor of renewable unit i
B_t^{max}	Maximum investment budget for year t in the planning horizon (\$)
$\widehat{W}_{i,t,cr}^{\omega}$	Maximum water withdrawal for non-renewable unit i in year t in water critical region cr (gallons)
$\widehat{W}_{i,t,cr}^{c}$	Maximum water consumption for non-renewable unit i in year t in water critical region cr (gallons)
$\widehat{W}_{t,r}^{c}$	Maximum water consumption for power sector in year t for water region r (gallons)
$\widehat{W}_{t,r}^{w}$	Maximum water withdrawal for power sector in year t for water region r (gallons)
$\alpha_{k,t}^{max}$	Upper bound of non-renewable type k in year t(%)
$\alpha_{k,t}^{min}$	Lower bound of non-renewable type k in year t(%)
ΔT_b	Duration of load block b (hr)
$\Delta U_{i,t}^{max}$	Maximum allowed number of new generating units i in year t
η_i	Heat Rate of generating unit i (MBtu/MWh)
μ_i	Fixed Operation/Maintenance cost of generating unit i (\$/MW-yr)
ν_i	Investment cost of candidate generating unit i (\$/MW)
ρ_i	Fuel price of non-renewable unit i (\$/MBtu)
Cap_i	Capacity of generating unit i (MW)
Cap_i^k	Capacity of non-renewable unit i with generation type k
D_i	Capacity derate factor for non-renewable unit i
df_t	Discount factor at year t
L_t	Amount of forecasted peak load of year t (MW)

$LB_{t,b}$ Load block b in year t (MW)

N_i^{ex} Number of existing generating unit i

PG_i^{max} Upper bound of power generation of unit i (MW)

PG_i^{min} Lower bound of power generation of unit i (MW)

Res^{max} Upper bound of required reserve

Res^{min} Lower bound of required reserve

$\widehat{W}_t^c$ Maximum water consumption for power sector in year t (gallons)

$\widehat{W}_t^w$ Maximum water withdrawal for power sector in year t (gallons)

W_i^ω Water withdrawal of non-renewable unit i (gal/MWh)

W_i^c Water consumption of non-renewable unit i (gal/MWh)

Variables

$\Delta U_{i,t}$ Number of candidate unit i to be added in year t

C_{Fuel} Total fuel cost in the planning horizon ($)

C_{INV}^k Total investment cost of non-renewable units in planning horizon ($)

C_{INV}^s Total investment cost of renewable units in the planning horizon ($)

C_{OM}^k Total fixed operation/maintenance cost of non-renewable units ($)

C_{OM}^s Total fixed operation/maintenance cost of renewable units ($)

C_{TOT} Total planning cost in the planning horizon ($)

$E_{i,t}^s$ Total energy supplied by renewable units i in year t (MWh)

$PG_{i,t,b}$ Generation of unit i in load block b in year t (MW)

$PG_{i,t,b}^s$ Generation of renewable unit i in load block b in year t (MW)

$Y_{i,t,b}$ Number of existing unit i to produce power in load block b in year t

$Z_{i,t,b}$ Number of candidate unit i for generation in load block b in year t

$U_{i,t}$ Number of candidate unit i to be added until year t

1. Introduction

1.1. Motivation and Background

Electric energy planning is a major part of energy planning. Electric energy planning refers to the study by which the optimal expansion plan of power system are determined over a long term horizon in future. Electric energy planning should be conducted to design the required power generation technologies and power transmission network to supply the future load and energy demands. Generation generation planning(GEP) is an important power system study which is carried out to determine the optimal expansion plan of generating units to supply the forecasted future peak loads, with minimum investment and operational costs subject to technical, economical and environmental constraints [1, 2]. Most of power generation in large scale power systems is provided by fossil fuel power plants. The input fuels include natural gas, coal, oil, and uranium. Since, power sector is a major source of environment pollution, in modern GEP studies the environmental concerns should be considered.

Due to the environmental concerns, the air and water impacts of power sector should be considered during expansion planning studies. Thermal power generation technologies need large amount of water for cooling purposes. To this end, the water constraints including the allowable amount of water for cooling purposes should be included in the modern GEP studies.

It is worthy to note that the world agreements on climate changes and global warming are reforming the power generation methods and technologies and therefore there is a strong correlation between the environmental policies and power generation technologies. Long term planning of low carbon and low water power generation technologies and water supply is a priority in modern power systems to make a trade-off between water, carbon emission, and energy sustainability objectives [3]. All thermal power generation technologies needs great volume of water for cooling purposes [4]. Based on the concept of water-energy nexus, water is a key resource for energy generation and access to the energy resources such as electric energy is vital for the provision of water services [5]. Due to serious concerns about the climate change and environment pollution, the carbon emission and water constraints should be addressed in clean power systems. Carbon emission is a major constraint in modern electric energy systems. Renewable resources are utilized as powerful technologies to realize the clean power generation system. In [6], a multistage stochastic planning model is proposed for capacity expansion planning under different greenhouse gas emission. In [7], the impacts of renewable resources on low carbon economy in energy systems are investigated. In [8], the co-planning of generation and transmission network is addressed in the presence of wind power plants. The number and location of the new transmission lines along with the capacity and location of the new wind generating units are determined using an MIP optimization model. The impacts of emission control on generation mix has been addressed in [9]. However, the greenhouse gas emission is not the only environmental concern of power generation by fossil fuel generation technologies. Water and energy are interconnected resources with strong mutual interactions. The regional limitations of energy and water supply are investigated in [10, 11].

The access of thermal power plants to freshwater for cooling purposes is increasingly limited. Scarcity of water resources and the cooling systems of nowadays steam power plants challenge the conventional GEP model. In this regard, the low water power generation expansion can be considered as a promising solution.

One of environmental challenges in GEP study is the water consumption and withdrawal of power generating units [12]. Most of steam power plants including coal, nuclear, and natural gas units as well as some non-hydro renewable technologies use significant amount of water for cooling and recondensing purposes [5, 13]. Thermo-electric power generation is the main consumer of freshwater withdrawal in many countries as well as the first non-agriculture large freshwater consumer [12]. According to [14], in England and Wales, the electricity sector is responsible for approximately half of all water abstraction and 40 % of non-tidal surface water abstractions. According to [15], the greatest use of water withdrawals in the United States is for power generation sector and the U.S. Geological Survey (USGS) estimated that 41 % of total U.S. freshwater withdrawals (i.e. 143 billion gallons per day) were for electricity generation in 2005. Due to freshwater limitation, the utilization of brackish water in thermoelectric generation in the American southwest [16]. Authors in [16] conclude that the State and federal policies are needed to foster deployment of brackish water cooling systems. In [17], the impact of coal-fired power generation on water withdrawal and consumption is investigated.

In [18], the authors reveal that China's direct water withdrawal by energy sectors (i.e., coal, oil, gas, petroleum and electricity) amounts to 117 $billion m^3$ in 2011.

The water availability constraints impacts the power generation mix, significantly [19, 20]. In [21], the amounts of water withdrawal and consumption per MWh generation of each generation technology has been reported. There are different solutions to reduce the water dependency of thermo-electric power plants such as switching from coal to natural gas generation technology [22], integration of non-hydro renewable energy resources [23], modifying the existing cooling systems [24], or utilizing municipal wastewater [25]. In [26], the impact of cooling systems for some power generation pathways is assessed and the water demand of some renewable technologies is investigated. The impact of power generation on water resources has been considered in GEP studies. In [27], using a software expansion tool, the optimal capacity expansion planning problem is addressed under cooling water constraints. The utilized model in [27] is a static expansion model without considering the details of a GEP model. In [14], the authors conclude that the pathway toward de-carbonisation with high nuclear and carbon capture and storage use the most water.

It seems that the low water and low carbon targets have complex mutual interactions in power sector. In [28], the impact of carbon capture technology on water use of coal-fired and gas-fired power plants is investigated. Mathematically the GEP problems are formulated as optimization problems. The objective function of GEP problem consists of different terms such as the investment cost of new generation assets, fuel cost of power generation, operating and maintenance costs. Additional constraints such as tunnel limits, maximum yearly budget, reserve requirement and power balance constraint can also be considered. Different optimization techniques such as evolutionary and analytic methods have been proposed for the solution of generation expansion models. In [29], a mixed integer programming technique has been developed for GEP problem in presence of hydro-power uncertainties. In [30], an MIP-based GEP model has been developed in which the reliability constraint loss of load probability(LOLP) has been taken into account. The details of GEP solution methods can be found in [31].

1.2. Research Gap and Contributions

Without considering the environmental constraints such as carbon emission and water use, the capital and fuel costs have great impacts on generation expansion plan. However, the environmental concerns changes the type of generation technologies especially in large scale power systems. While the carbon emission targets have been well included in modern generation expansion studies, less efforts have been made to consider the water constraints in modern power generation expansion studies. Without considering the water resource limitations, the resulted power generation mix will impact the surrounding environment negatively with irreversible damages.

Renewable resources are considered as water smart generation technologies and they need very limited amount of water during power generation process. Ideally, wind power plants don't consume water for power generation and Photo-Voltaic (PV) power plants needs a little water for washing panels. To this end, the renewable resources including wind and PV power plants can be considered as low water generation technologies in GEP model.

In this paper, a long term multi-period GEP model with with considering water resource limitation is proposed. The main contributions of this work are as follows:

- A long term electric energy system planning model is proposed to determine the optimal type, capacity, installation time, and the proper cooling system of new generation technologies in large scale electric energy systems. In this study we have assumed that the proposed water constrained GEP study is conducted for determining the power generation mix from year 2025 to year 2045 which results in a 21-year planning horizon. In order to minimize the impacts of thermal power generation technologies on water resources, the water consumption and withdrawal of generation technologies with different cooling systems in presence of regional water limits are considered in the proposed electric energy planning model. In fact, presenting a new Low Water GEP (LW-GEP) model is the main contribution of this paper. A vast range of technical and economic constraints are considered in the proposed LW-GEP model.

- The renewable generating technologies including wind and solar power are included in the proposed LW-GEP model as a water smart solution in future power generation mix. The impacts of renewable integration on reduction of planning cost and water saving are investigated via the proposed LW-GEP model.

- The proposed environmental-friendly multi-period LW-GEP model is formulated as an MIP optimization problem. The optimal solution of the proposed multi-period LW-GEP model is guaranteed by the CPLEX algorithm.

1.3. Paper Structure

The rest of this paper is organized as follows. In section 2, the overall structure of the proposed low water power generation expansion model is introduced. In Section 3, the formulation of the proposed multi-period GEP model including the objective function and the related constraints is introduced. In Section 4, the water constraints of thermal power plants are presented. In Section 5, the simulation results of the proposed method over a large scale test system are given. Also, the full techno-economic characteristics of the existing and candidate generation technologies are given in Section 5. Finally, the paper is concluded in Section 6.

2. Overall Structure of The Proposed Expansion Model

The overall structure of the proposed LW-GEP is illustrated in Fig. 1. The input data includes the forecasted yearly peak loads over the planning horizon, the renewable resources data, the technical and economic characteristics of existing and candidate generating units. Also there are technical and economic limits that should be determined as the input of the GEP model. Details of these constraints will be given in next parts. In order to form a LW-GEP model, the techno-economic data of available and candidate cooling systems are required. Different cooling technologies including recirculating, dry-cooled, cooling pond, and once-through are considered. Also, the water constraints including the limits on available water for consumption and withdrawal are defined and considered in the proposed LW-GEP model. Water Withdrawal refers to the total amount of water a power plant takes in from a ware resource such as a river or lake, some of which is returned. The cooling process increase the temperature of the withdrawn water which is harmful for the downstream ecosystems. Water consumption is the amount lost to evaporation during the cooling process. Due to climate change and the population growth, the access of thermal power plants to water resources is limited. The amount of water consumption and withdrawal depends on the generation technology and related cooling system. Additionally, different water regions should be defined. Each unit is belongs to a specific geographic location. A water region refers to a collection of geographic locations twith the same water conditions. The proper generation technology and the related cooling system in each region depends on the water availability in that region. The Falkenmark indicator is one of the most widely used measure of water stress. The Falkenmark indicator is defined as the fraction of the total annual runoff available for human use. Based on Falkenmark indicator, the water conditions in a region is classified as: No Stress, Stress, Scarcity, and Absolute Scarcity. The regions with Falkenmark indicator of greater than 1700 m^3 (per capita per year) are considered as No-Stress region. In Stress regions, the Falkenmark indicator is between 1000 and 1700 m^3 (per capita per year). The Falkenmark indicator in Scarcity condition is between 500 and 1000 m^3 (per capita per year). Finally, the regions with Falkenmark indicator lower than 500 m^3 (per capita per year) are interpreted as Absolute Scarcity. In this paper, three different water regions including No-Stress, Stress and Scarcity are assumed. The output of the developed LW-GEP include the type, size, and capacity of new thermal and renewable generating units along with the proper cooling system for thermal generating units.

3. Multi-Period LW-GEP Model

There are two different types of generation expansion planning approaches including static and multi-period models. The static expansion planning is carried out for a single or target year in the future without considering the details of expansion plan during the planning horizon. The multi-period planning approach considers all periods of the planning horizon. In other words, in multi-period GEP models, the timing of all installations are determined. The computational complexities of the multi-period GEP model is higher than the static GEP model, however, the multi-period expansion plans is more practical than the results of static GEP model. In this paper, the multi-period GEP model with a long term horizon of 21-years is considered.

The proposed multi-period GEP model is formulated as an optimization model. In order to guarantee the optimality of the expansion plan, the proposed GEP mdel is represented by a mixed-integer programming (MIP) optimization model. In this section, the mathematical model of the proposed multi-period GEP model, including the objective function and the related constraints are defined.

3.1. Objective Function

Equation (1) represents the objective function which includes the net present values of different costs as follows:

$$C_{TOT} = C^k_{INV} + C^s_{INV} + C_{Fuel} + C^k_{OM} + C^s_{OM} \tag{1}$$

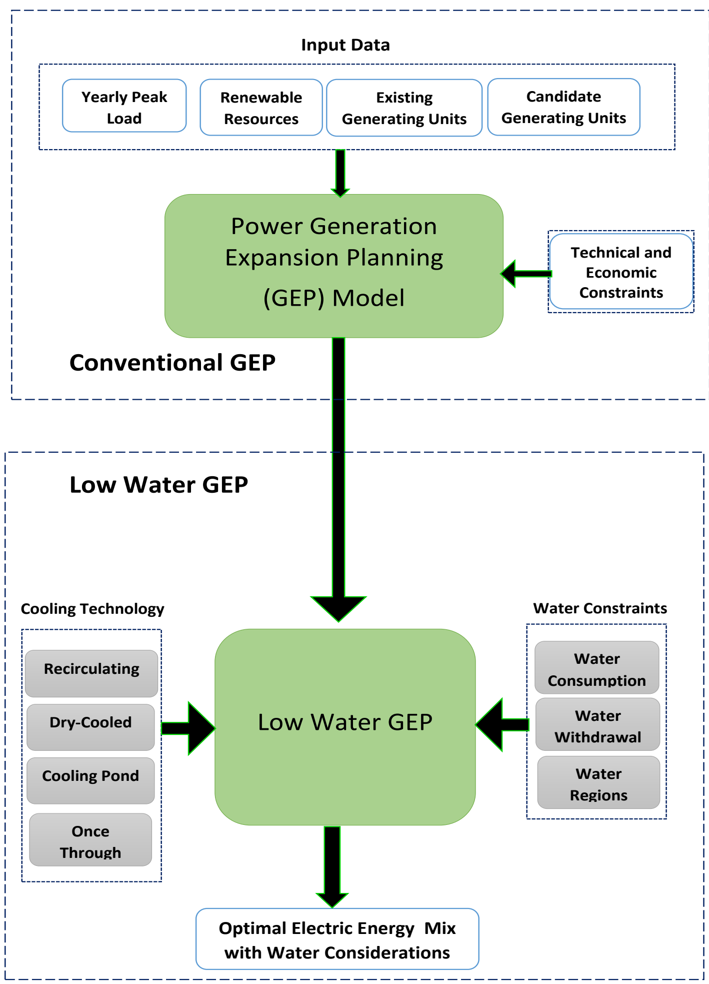

Figure 1: Overall Structure of the Proposed Low Water Generation Expansion Model

The total investment cost, i.e. the capital cost of new thermal units and non-hydro renewable resources are calculated using (2)-(3). In (2)-(3), for calculating the investment cost at year t, the discount factor is considered as df_{t-1}, because it is assumed that the investment decision are made at the beginning of the related planning year. The total fuel cost for power generation is determined based on (4). In (4), the discount factor is considered as df_t, because it is assumed that the fuel costs are incurred at the end of the related planning year. Finally, the total maintenance cost of thermal units and non-hydro renewable resources are expressed in (2)-(6), respectively. The maintenance costs are assumed to be the fixed costs and therefore it depends on the nominal capacity of generating units.

$$C_{INV}^{k} = \sum_{t \in \Omega_t} \sum_{i \in \Omega_g^k} \nu_i \times Cap_i \times \Delta U_{i,t} \times df_{t-1} \tag{2}$$

$$C_{INV}^{s} = \sum_{t \in \Omega_t} \sum_{i \in \Omega_g^s} \nu_i \times Cap_i \times \Delta U_{i,t} \times df_{t-1} \tag{3}$$

$$C_{Fuel} = \sum_{t \in \Omega_t} \sum_{i \in \Omega_g} \sum_{b \in \Omega_b} \rho_i \times \eta_i \times PG_{i,t,b} \times \Delta T_b \times df_t \tag{4}$$

$$C_{OM}^{k} = \sum_{t \in \Omega_t} \sum_{i \in \Omega_g^k} \mu_i \times Cap_i \times U_{i,t} \times df_t \tag{5}$$

$$C_{OM}^{s} = \sum_{t \in \Omega_t} \sum_{i \in \Omega_g^s} \mu_i \times Cap_i \times U_{i,t} \times df_t \tag{6}$$

3.2. Capacity and Reserve Constraints

The load demand in each year varies from the base load (i.e. the minimum amount of load during a given year) to the peak load. The total installed capacity of all generating units must be adequate enough to supply the load demand at all times. To this end, at each year of the planning horizon, the total installed capacity of existing and candidate units must be greater than the sum of the yearly peak load and a minimum required reserve as follows.

$$\sum_{i\in\Omega_g^s} Cap_i \times U_{i,t} + \sum_{i\in\Omega_g^k} Cap_i \times D_i \times U_{i,t} + \sum_{i\in\Omega_g^{ex}} Cap_i \geq (1 + Res^{min}) \times L_t \tag{7}$$

In (7), for the sake of simplicity, the full capacity of renewable units has been considered in reserve constraint. The reserve constraint is only considered for the peak load point of each year, and it is assumed that at the peak load condition the renewable units provide their full capacity. Without loss of generality, any fraction of full capacity of renewable units can be considered in reserve constraint.

To handle the scenarios of renewable generation and load demand, the clustering methods can be utilized to extract some representative days for each planning year with considering the correlation between renewable and Load variations in each planing year [32]. Using the clustering approaches, a certain number of representative days can be extracted for the load and renewable generation scenarios considering their correlations. Such techniques result in a limited number of renewable and load scenarios. In this condition, we can simply use the obtained renewable scenario at peak load condition for the reserve constraint. Since the focus of this study is the investigation of the impacts of water use constraints on generation expansion problem, the correlation-based clustering approaches are not utilized for modeling the stochastic nature of renewable resources.

Also, it is assumed that for existing units, the term ($\sum_{i\in\Omega_g^{ex}} Cap_i$) is the derated capacity. In order to limit the solution space and speed up the solution process, the maximum amount of required reserve can also be considered as given in (8).

$$\sum_{i\in\Omega_g^s} Cap_i \times U_{i,t} + \sum_{i\in\Omega_g^k} Cap_i \times D_i \times U_{i,t} + \sum_{i\in\Omega_g^{ex}} Cap_i \leq (1 + Res^{max}) \times L_t \tag{8}$$

3.3. Power Balance Constraints

The balance between generation and load demand must be preserved at each load block of each year as given by (9). According to (10), the power generation of each renewable unit in all load blocks of each year is equal to its nominal capacity multiplied by the capacity factor of that unit. The capacity factor of a renewable unit is defined as the ratio of its total generated energy and its maximum nominal energy in a given year and is assumed to be known based on the historical data. The generated energy of a renewable unit is intermittent and depends on the weather conditions such as wind speed and solar radiation. For wind farms, the wind speed is not at its nominal value in all times. Also, the solar radiation is available only during limited hours of the day. For example, when a Photo-Voltaic station generates energy at its nominal capacity for 5 hours of each day in all 365 days of the year, its capacity factor will be equal to 0.21 (i.e. $cf = \frac{5*356}{24*365} = 0.21$). Regarding these issues, the renewable units are not able to generate energy at their nominal capacity in all times. For different renewable units, the value of cf_i varies between 0.2 to 0.5 [33].

$$\sum_{i \in \Omega_g^{ex}} PG_{i,t,b} + \sum_{i \in \Omega_g^{k}} PG_{i,t,b} + \sum_{i \in \Omega_g^{s}} PG^s_{i,t,b} = LB_{t,b} \quad \forall t \in \Omega_t \,, \forall b \in \Omega_b \tag{9}$$

$$PG^s_{i,t,b} = Cap_i \times U_{i,t} \times cf_i \quad \forall b \in \Omega_b, \forall t \in \Omega_t, i \in \Omega_g^s \tag{10}$$

For non-renewable generation technologies, the maximum and minimum generation levels in each load block must be satisfied. In this regard, constraints given in (11) and (12) are defined.

$$Z_{i,t,b} \times PG_i^{min} \leq PG_{i,t,b} \leq Z_{i,t,b} \times PG_i^{max} \qquad \forall t \in \Omega_t, \forall b \in \Omega_b, \forall i \in \Omega_g^k \tag{11}$$

$$Y_{i,t,b} \times PG_i^{min} \leq PG_{i,t,b} \leq Y_{i,t,b} \times PG_i^{max} \qquad \forall t \in \Omega_t, \forall b \in \Omega_b, \forall i \in \Omega_g^{ex} \tag{12}$$

A major part of the planning cost is the generation cost. Also, the total required water for cooling purposes highly depends on the amount of power generation. Therefore, it is required to determine the economic loading of all generating units in each load block at each year of the planning horizon. To this end, new variables should be defined to represent the loading of generating units. Using the integer variable $Z_{i,t,b}$, based on (11) and (13), the candidate units participate in power generation in each load block of each year, if they are constructed in that year. Based on (12) and (14), the same rule is considered for existing units using the integer variable of $Y_{i,t,b}$.

$$Z_{i,t,b} \leq U_{i,t} \qquad \forall t \in \Omega_t \,, \forall b \in \Omega_b \,, \forall i \in \Omega_g^s \tag{13}$$

$$Y_{i,t,b} \leq N_i^{ex} \qquad \forall t \in \Omega_t \,, \forall b \in \Omega_b \,, \forall i \in \Omega_g^{ex} \tag{14}$$

3.4. Tunnel Limit and Budget Constraints

Due to economic and technical restrictions, the number of new generating units that can be installed in each stage of planning horizon is limited. Maximum number of expansion candidate permitted for expansion in each year is called the tunnel width. Therefore, the tunnel constraints are defined as given in (15)-(16). The constraints given in (17) is considered to limit the annual budget for investment, respectively.

$$U_{i,t} - U_{i,t-1} = \Delta U_{i,t} \qquad \forall t \in \Omega_t\,,\, \forall i \in \Omega_g^k \tag{15}$$

$$\Delta U_{i,t} \leq \Delta U_{i,t}^{max} \qquad \forall t \in \Omega_t\,,\, \forall i \in \Omega_g^k \tag{16}$$

$$\sum_{i\in\Omega_g^k} \nu_i \times Cap_i \times \Delta U_{i,t} \times df_{t-1} + \sum_{i\in\Omega_g^s} \nu_i \times Cap_i \times \Delta U_{i,t} \times df_{t-1} \leq B_t^{max} \quad \forall t \in \Omega_t \tag{17}$$

3.5. Generation Mix Constraints

Different types of generation technologies (e.g. steam, open cycle, combined cycle, and nuclear) are considered as expansion candidates. Due to economic and technical considerations, it is preferred to adjust the total installed capacity of each generation technology. Based on the generation mix constraint, at each stage of the planning horizon, the total capacity of a given type of generation technology should remain between a minimum and maximum value. To this end, constraints given by (18) and (19) are defined. The choice of $\alpha_{k,t}^{max}$ and $\alpha_{k,t}^{min}$ have a significant impact on expansion planning.

$$\alpha_{k,t}^{max}(\sum_{i\in\Omega_g^k} Cap_i \times U_{i,t} + \sum_{i\in\Omega_g^s} Cap_i \times U_{i,t} + \sum_{i\in\Omega_g^{ex}} Cap_i)$$

$$\geq \sum_{i\in\Omega_g^k} Cap_i^k \times U_{i,t}^k + \sum_{i\in\Omega_g^{ex}} Cap_i^k\,,\, k \in \Omega_k^{all} \tag{18}$$

$$\alpha_{k,t}^{min}(\sum_{i\in\Omega_g^k} Cap_i \times U_{i,t} + \sum_{i\in\Omega_g^s} Cap_i \times U_{i,t} + \sum_{i\in\Omega_g^{ex}} Cap_i)$$

$$\leq \sum_{i\in\Omega_g^k} Cap_i^k \times U_{i,t}^k + \sum_{i\in\Omega_g^{ex}} Cap_i^k\,,\, k \in \Omega_k^{all} \tag{19}$$

4. Water Constraints

A key part in water withdrawal and consumption of thermo-electric power plants is the cooling system. Different cooling systems including 1) once-through, 2) Wet(recirculating) cooling and 3) Dry cooling system are utilized. Once-through systems use cooling water once before discharging it. Such cooling systems withdraw much more water than other types of cooling technologies. Closed or recirculating cooling systems withdraw less water than the once-through systems. However, the amount of water consumption in recirculating systems is about twice the once-through systems due to water evaporation. Unlike the other types of cooling systems, the dry-cooled systems, blows air across steam carrying pipes to cool them without any water consumption or withdrawal. While each cooling system has an interval for its water withdrawal and consumption [21], the median of water consumption and withdrawal for different generating unit based on the type of cooling system are shown in Fig. 2 and Fig. 3, respectively. As shown in Fig. 2, the water consumption of Natural Gas Fired Steam (NG-ST) power plants with Recirculating cooling system is approximately equal to $826gal/MWh$. The Natural Gas Fired Combined Cycle (NG-CC) power plants have the minimum water consumption which is approximately equal to $100gal/MWh$. According to Fig. 3, the Nuclear power plants have the maximum water withdrawal that is approximately equal to $44350gal/MWh$.

For LW-GEP model, six constraints in three layers (e.g. national, regional, and local layers) can be applied. In the first layer, constraints given in (20) and (21) impose limitation on total available amount of water consumption and withdrawal for power sector in each planning stage.

$$\sum_{i\in\Omega_g}\sum_{b\in\Omega_b} W_i^c \times PG_{i,t,b} \times \Delta T_b \leq \widehat{W}_t^c \quad \forall t \in \Omega_t \tag{20}$$

$$\sum_{i\in\Omega_g}\sum_{b\in\Omega_b} W_i^\omega \times PG_{i,t,b} \times \Delta T_b \leq \widehat{W}_t^\omega \quad \forall t \in \Omega_t \tag{21}$$

In the second layer, constraints given in (22) and (23) impose limitation on total available amount of water consumption and withdrawal for each region in each stage of planning horizon in a regional basis. Water regions are sorted into different categories as No-Stress, Stress, and Scarcity.

$$\sum_{i\in\Omega_g^r}\sum_{b\in\Omega_b} W_i^c \times PG_{i,t,b} \times \Delta T_b \leq \widehat{W}_{t,r}^c \quad \forall t \in \Omega_t\ , \forall r \in \Omega_r \tag{22}$$

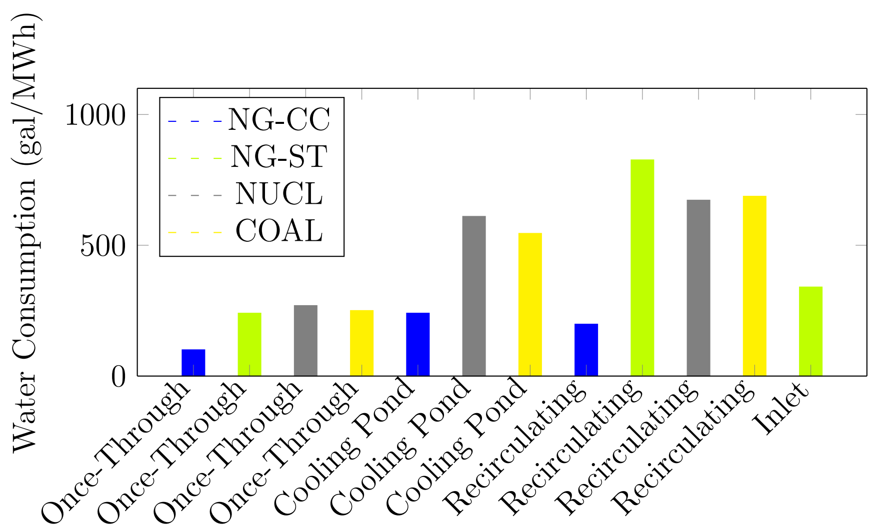

Figure 2: Water Consumption of generation technologies with related cooling system

$$\sum_{i\in\Omega_g^r}\sum_{b\in\Omega_b} W_i^{\omega} \times PG_{i,t,b} \times \Delta T_b \leq \widehat{W}_{t,r}^{\omega} \qquad \forall t \in \Omega_t \,, \forall r \in \Omega_r \tag{23}$$

Finally in the third level, the constraints given in (24)-(25) impose limitation on the maximum available consumption and withdrawal water for each generating unit in water critical regions.

$$\sum_{b\in\Omega_b} W_i^{c} \times PG_{i,t,b} \times \Delta T_b \leq \widehat{W}_{i,t,cr}^{c} \quad \forall t \in \Omega_t, \forall cr \in \Omega_r^{cr}, \forall i \in \Omega_g^{cr} \tag{24}$$

$$\sum_{b\in\Omega_b} W_i^{\omega} \times PG_{i,t,b} \times \Delta T_b \leq \widehat{W}_{i,t,cr}^{\omega} \quad \forall t \in \Omega_t, \forall cr \in \Omega_r^{cr}, \forall i \in \Omega_g^{cr} \tag{25}$$

The regional constraints represented in the second layer are mandatory, while the first layer and third layer constraints might be considered if needed.

5. Case Study

The proposed low water power generation expansion model is simulated for a large scale test system over a 21-years planning horizon with and without considering water constraints. The developed test system is divided into three

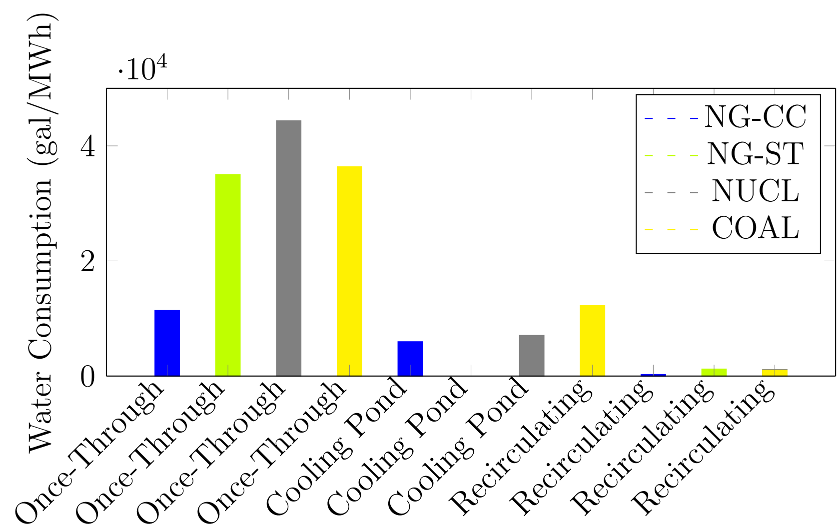

Figure 3: Water withdrawal of generation technologies with related cooling system

different water regions as Normal or No-Stress (Region 1), Stress (Region 2), and Scarcity (Region 3). In first part, the input data are introduced. In second ad third parts, the simulation results are given. As water smart solutions, a renewable integration scenario is presented in fourth part. The proposed LW-GEP model is formulated as a Mixed Integer Programming (MIP) optimization model and is solved by CPLEX algorithm in GAMS using an Intel Core i7 PC running at 3.6GHz with 32GB of RAM. Details of CPLEX algorithm and GAMS software can be found in [34] and [35], respectively.

5.1. Input Data

In most of GEP studies, conventionally, the data of test system including the techno-economic characteristics of existing and candidate generation technologies are reported via standard Tables. We have constructed a new large scale test system for our study based on practical data. The characteristics of generation technologies have been defined according to [33, 36]. Input data includes techno-economic data of the existing and candidate generating units. It is assumed that 1) the test system is a natural gas dominated system, 2) there is no coal power plant, and 3) only one nuclear power plant

Table 1: Technical parameters of existing thermal generators

Fuel Type	**Technology**	**Capacity (MW)**	**Heat Rate (Btu/kWh)**	**Min.Out (MW)**	**Existing Number**	**Cooling System (Number of existing Units)**			
						OT	RC	PD	DR
Nuclear	Steam	1020	10450	1000	1	1	0	0	0
Natural Gas	Combined Cycle	960	7667	480	10	3	7	0	0
Natural Gas	Combined Cycle	480	7667	240	14	1	13	0	0
Natural Gas	Open Cycle	320	10935	160	39	No Cooling			
Natural Gas	Open Cycle	160	10935	80	12	No Cooling			
Natural Gas	Steam	440	9247	200	17	0	17	0	0
Natural Gas	Steam	320	9247	160	12	0	12	0	0
Natural Gas	Steam	150	9247	60	11	0	11	0	0

Table 2: Economic parameters of existing thermal generators

Fuel Type	**Technology**	**Fuel Price($/MBtu)**	**Fixed O&M Cost($/kw-yr)**	**Variable O&M Cost($/MWh)**
Nuclear	Steam	0.85	115	0.75
Natural Gas	Combined Cycle	3.45	5.7	3.2
Natural Gas	Combined Cycle	3.45	6	3.5
Natural Gas	Open Cycle	3.45	17.8	4.4
Natural Gas	Open Cycle	3.45	18.1	4.7
Natural Gas	Steam	3.45	71.5	4.3
Natural Gas	Steam	3.45	71.9	4.7
Natural Gas	Steam	3.45	72.3	5

exists. The technical and economic parameters of the existing units are reported in Table 1 and Table 2, respectively. The technical data consists of Fuel Type, Technology, Capacity, Heat Rate, Minimum power output of the generating unit, the total number of existing units and the cooling system. The existing cooling systems are assumed as Once-Through (OC) and Recirculating (RC). The economic data includes the Fuel Price, Fixed and Variable Operating/Maintenance costs. According to Table 1, the capacity of existing units varies from 150 MW to 1020 MW for different generation technologies. Also the Heat Rate of existing units changes from 7667 Btu/kWh to 10935 Btu/kWh.

Also, The technical and economic parameters of the candidate units are reported in Table 3 and Table 4, respectively. According to Table 3, the capacity of candidate units varies from 160 MW to 2200 MW. Also the Heat Rates of candidate units change from 6350 Btu/kWh to 10461 Btu/kWh. It should be noted that for candidate units, only Wet (recirculating) and Dry cooling are considered as candidate cooling systems. Also, for candidate Nuclear units the cooling system s assumed as Once-Through. The capacities reported in Table 1 and Table 3 are nominal capacities for the corresponding units. For accurate modeling, an average derate factor based on the type of generating units and ambient conditions for each water region are assumed. In this paper, the average derate factors of open-cycle and combined cycle generating units for Region 1, Region 2 and Region 3 are assumed to be 23% and 18%, 27% and 26%, 28% and 27%, respectively. The capacity of other generating technologies are not derated. The data of candidate cooling systems for candidate units in all three water regions are reported in Table 5. According to Table 5, the impact of cooling system on efficiency (i.e. the inverse of Heat Rate) is considered. In this paper, it is assumed that No-stress and Scarcity water regions have the lowest and highest ambient temperatures, respectively. The data of cooling system based on the ambient temperature can be found in [36]. The forecasted peak loads from 2025 to 2045 are reported in Table 6. According to Table 6, the yearly peak loads vary from 50290 MW at year 2025 to 94550 MW at year 2045.

5.2. Simulation Cases

The simulation results are presented in three different cases. Case 1 is the Business as Usual case, i.e. , a conventional generation expansion model without any consideration on the water consumption and withdrawal. In Case 2 and Case 3, the water limits are imposed as a percentage of amounts

Table 3: Technical parameters of candidate Units

Thermal Units									
Fuel Type	**Technology**	**Capacity (MW)**	**Heat Rate (Btu/kWh)**	**Min. Output**	**Tunnel Limit**	**Candidate Cooling Systems**			
Nuclear	Steam	2200	10461	1760	2	OT	RC	PD	DR
Coal	Steam	600	9221	300	9	OT	RC	PD	DR
Natural Gas	Combined Cycle	960	6350	288	9	OT	RC	PD	DR
Natural Gas	Combined Cycle	480	6750	288	9	OT	RC	PD	DR
Natural Gas	Open Cycle	320	8500	80	9	No Cooling			
Natural Gas	Open Cycle	160	9600	40	9	No Cooling			
Natural Gas	Steam	320	7754	160	9	OT	RC	PD	DR
Natural Gas	Steam	160	8124	80	9	OT	RC	PD	DR
Renewable Units									
	Technology	**Capacity (MW)**	**Capacity Factor (%)**	**Maximum Penetration (MW)**		**Cooling System**			
	Wind	150	40	1050		No Cooling			
	PV(Utility Scale)	50	30	1500		No Cooling			

Table 4: Economic parameters of candidate Units

Thermal Units					
Fuel Type	**Technology**	**Capital Cost($/kW)**	**Fuel Price($/MBtu)**	**Fixed O&M Cost($/kw-yr)**	**Variable O&M Cost($/MWh)**
Nuclear	Steam	6500	0.85	115	0.75
Coal	Steam	5169	1.45	72.12	5
Natural Gas	Combined Cycle	999	3.45	5.7	3.2
Natural Gas	Combined Cycle	1200	3.45	6	3.5
Natural Gas	Open Cycle	800	3.45	17.8	4.4
Natural Gas	Open Cycle	950	3.45	18.1	4.7
Natural Gas	Steam	6900	3.45	71.9	4.7
Natural Gas	Steam	7500	3.45	72.3	5
Renewable Units					
	Technology	**Capital Cost($/kw)**	**Fuel Price($/MBtu)**	**Fixed O&M Cost($/kw-yr)**	**Variable O&M Cost($/MWh)**
	Wind	1350		30	0
	PV(Utility Scale)	1100		10	0

Table 5: Techno-Economic parameters of cooling systems for candidate units

Units				**Water Regions**					
Fuel Type	**Technology**	**Capacity (MW)**	**Cooling System**	**No Stress**		**Stress**		**Scarcity**	
				Heat Rate (Btu/kWh)	**Capital cost ($/kW)**	**Heat Rate (Btu/kWh)**	**Capital cost ($/kW)**	**Heat Rate (Btu/kWh)**	**Capital cost ($/kW)**
Coal	Steam	600	Recir.	9221	98.6	9478	108.5	9666	118.3
Coal	Steam	600	Dry	9348	244.8	10185	269.3	10662	293.8
NG	CC	960	Recir.	6350	52.6	6470	57.9	6557	63.1
NG	CC	960	Dry	6408	130.6	6790	143.7	7000	156.7
NG	CC	480	Recir.	6750	26.3	6886	28.9	6985	31.6
NG	CC	480	Dry	6811	65.3	7245	71.8	7483	78.4
NG	Steam	320	Recir.	7754	52.6	7935	57.9	8066	63.1
NG	Steam	320	Dry	7844	130.6	8425	143.7	8749	156.7
NG	Steam	160	Recir.	8124	26.3	8321	28.9	8466	31.6
NG	Steam	160	Dry	8222	65.3	8862	71.8	9222	78.4
NG	OC	320		8500		8717		8945	
NG	OC	160		9600		9878		10172	

Table 6: Yearly Peak Load Forecast for the Test System

Year	2025	2026	2027	2028	2029	2030	2031
Load(MW)	50290	52407	54626	57179	59257	61612	63960
Year	2032	2033	2034	2035	2036	2037	2038
Load(MW)	66094	68447	70673	72858	75147	77315	79514
Year	2039	2040	2041	2042	2043	2044	2045
Load(MW)	81728	83868	86064	88197	90031	92450	94550

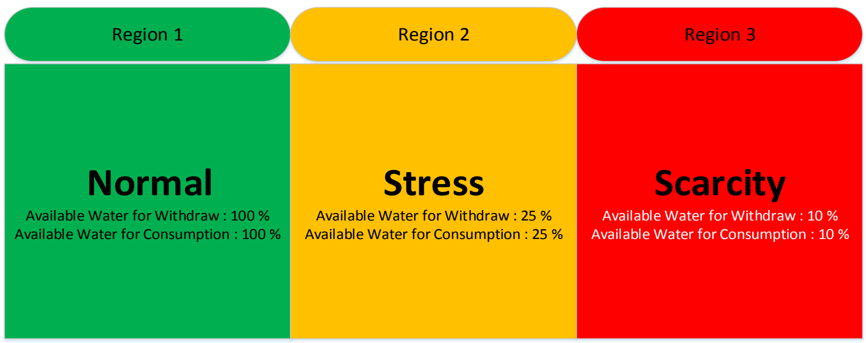

Figure 4: Water consumption and withdrawal limits of regions in Case 3

of water consumption and withdrawal obtained from Business as Usual case. In cases 2 and 3 , only the second layer (regional layer) is considered and the first and third layers.

The water limits in all regions under three cases have been reported in Table 7. For better clarification, the water limits of regions under the assumptions of Case 3 are illustrated in Fig. 4.

The minimum and maximum shares of installed capacity in Regions 1, 2, and 3 at each year of planning horizon are assumed to be $[15\% - 25\%]$, $[50\% - 60\%]$, and $[20\% - 30\%]$ of the total capacity, respectively, however, based on the system owner's policy and regarding techno-economic factors, any other percentages can be considered. It is assumed that Region 1 has no water limit in all three cases. However, in Region 2 and Region 3, hard limits on water availability are imposed. Although the exact volumes of available water over the long term planning horizon is subject to uncertainty, but these hard limits show the importance of water saving through selecting the proper generation technologies and cooling systems. The obtained cumulative new installed capacity over the planning horizon is shown in Fig. 5 for all three

Table 7: Simulation results for different cases

	Case No		
	Case 1	**Case 2**	**Case 3**
	Water Limit as Percentage of Business as Usual		
	Region1: 100 Region2: 100 Region3: 100	Region1: 100 Region2: 50 Region3: 33	Region1: 100 Region2: 25 Region3: 10
Region	New Installed Cap. (MW)		
All	85355	85455	85440
1	19840	19840	19840
2	47520	47680	47680
3	17920	17920	17920
Region	New Installed CC Wet-Cooled Cap.(MW)		
all	55680	20160	10560
1	13440	4800	4800
2	29760	14400	5760
3	12480	960	0
Region	New Installed CC Dry-Cooled Cap.(MW)		
All	0	30720	38400
1	0	8640	9600
2	0	13440	20160
3	0	8640	8640
Region	New Installed OC Cap.(MW)		
All	29600	34560	36480
1	6400	6400	5440
2	17760	19840	21760
3	5440	8320	9280
Region	New Practical(Derated) Installed Cap.(MW)		
All	64038	64047	64051.2
1	15948	15948	15996.8
2	34987	35084	35065.8
3	13027	12998	12988.6
	Cost (billion $)		
Total Cost	131.77	136.28	140.85
Capital Cost	50.56	51.5	51.8
Fuel cost	78.47	81.85	85.9
Execution Time (sec)	303	441	672

cases. While the proposed model is solved for a 21-years horizons in steps of 1 year, for the sake of simplicity, the results are reported only for five stages. According to Fig. 5, it can be seen that in Case 1 , due to the lack of water constraints, the Wet-cooled combined-cycle units are in the top priority for generation expansion. Indeed, in Case 1 , the generation technologies are selected based on their investment and generation costs, and therefore the Wet-cooled combined-cycle units are selected due to their higher efficiencies. However, in Case 2, where the total available volume of water in Region 2 and Region 3 was reduced to 50 % and 33% of their corresponding values in Case 1 , the Dry-cooled combined-cycle units are in the top priority for expansion. Also, in Case 2, the total capacity of the new open-cycle units is more than its corresponding value in Case 1. In Case 3, the total amount of water consumption and withdrawal in Region 2 and Region 3 are reduced to 25 % and 10% of their corresponding values in Case 1. According to Fig. 5, the generation mix in Case 3 is highly dominated by Dry-cooled combined-cycle and open-cycle units. It can be seen that in Case 3, the total new capacity of Wet-Cooled combined-cycle units is reduced significantly, while due to the water limits, the low water generation technologies including Dry-Cooled combined cycle and open-cycle technologies are chosen for expansion. The generation mix in each region is reported in Table 7. According to Table 7, the total amount of Wet-cooled combined-cycle units in Regions 2 and 3, is reduced from 29760 MW and 12480 MW in Case 1, to 5760 MW and 0 MW in Case 3. Also, the total share of open-cycle units has increased from 29600 MW in Case 1 to 36480 MW in Case 3 . As reported in Table 7, under water constraints, the total capacity of new combined-cycle power plants with Dry cooling system is increased from zero MW in Case 1 to 38400 MW in Case 3. The total generated energy is shown in Fig. 6. According to Fig. 6, the produced energy by Wet-cooled units in Case 2 and Case 3 reduces during the planning horizon and the low water generating units such as dry-cooled combined-cycle and open-cycle units contribute more in energy production due to the water limits in Case 2 and Case 3. However, the dry-cooled combined-cycle and open-cycle units have lower efficiency with respect to Wet-cooled combined-cycle units, thus the total fuel cost as well as the total capital cost are increased. In Fig. 6, the total energy of all existing and new generating units have been illustrated. According to Table 7, the total cost of planning over the planning horizon is increased from \$131.77 billion in Case 1 to \$140.85 billion for Case 3 and additional \$9.65 billion cost is incurred due to the water constraints. The execution time of the solution process varies

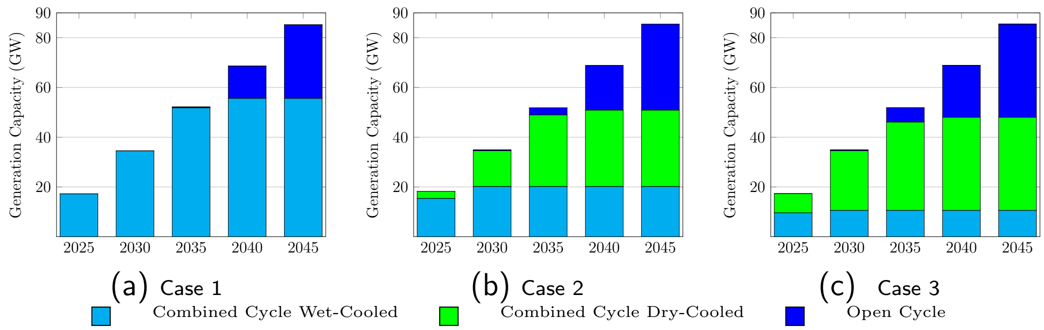

Figure 5: New Installed Capacity for different Cases

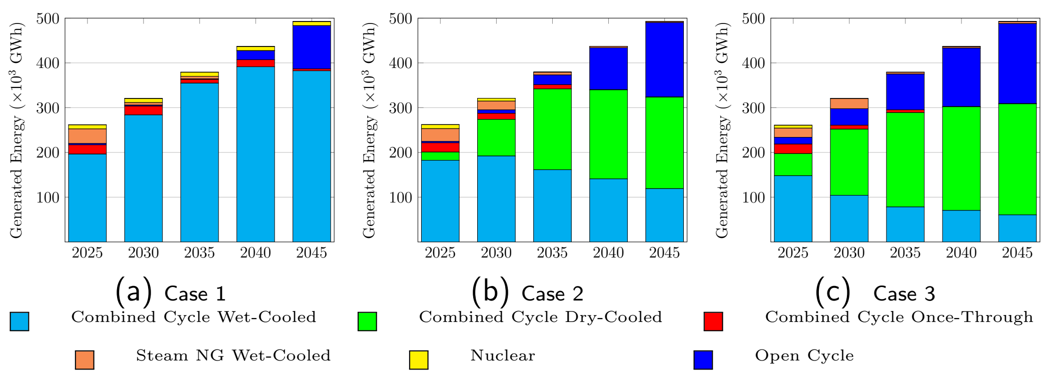

Figure 6: Generated energy for different Cases

from 303s to 672s which is acceptable for the test system.

5.3. Further discussion about water saving

In Case 1, for all regions, no water constraint is imposed. Therefore, according to Fig. 8, under the assumptions of Case 1, the amount of water withdraw over the planning horizon is fluctuating (i.e. is not decreasing over the planning horizon). However, in Case 2 and Case 3, the water constraints are imposed and the amount of water withdraw is decreasing over the planning time. Indeed, we have defined three different cases. In Case 2 and Case 3, the maximum amount of available water for withdrawal and consumption purposes are assumed as percentage of their related values in Case 1. As reported in Table 7, in Case 3, the amount of water withdraw in Region 3 under the assumptions of Case 3 is not allowed to exceed 10 % of total water withdraw in Case 1. Therefore, the amount of available water

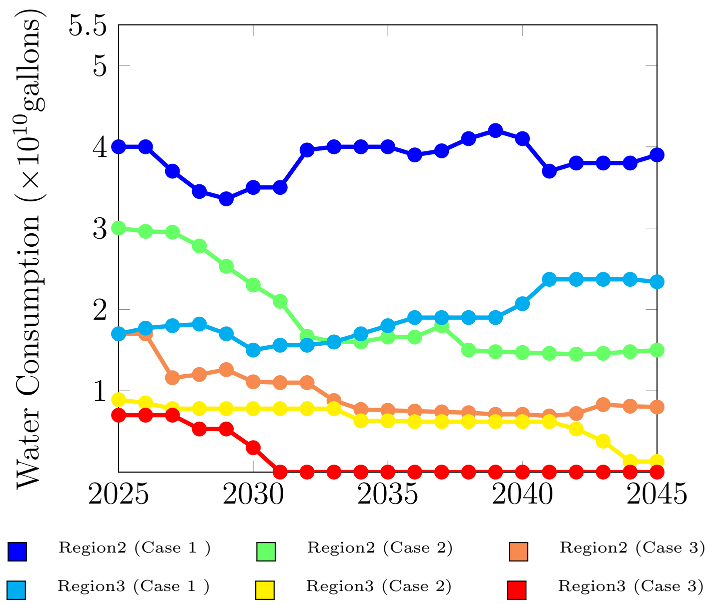

Figure 7: Yearly water consumption of regions in all cases

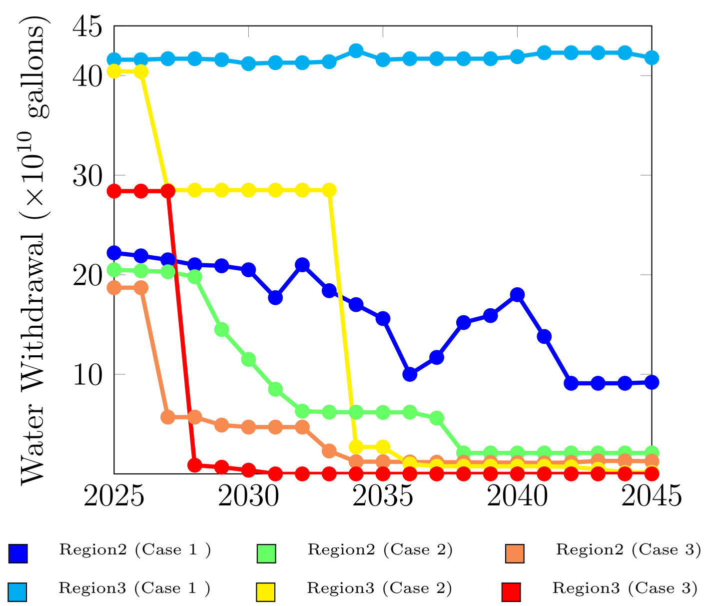

Figure 8: Yearly water withdrawal of regions in all cases

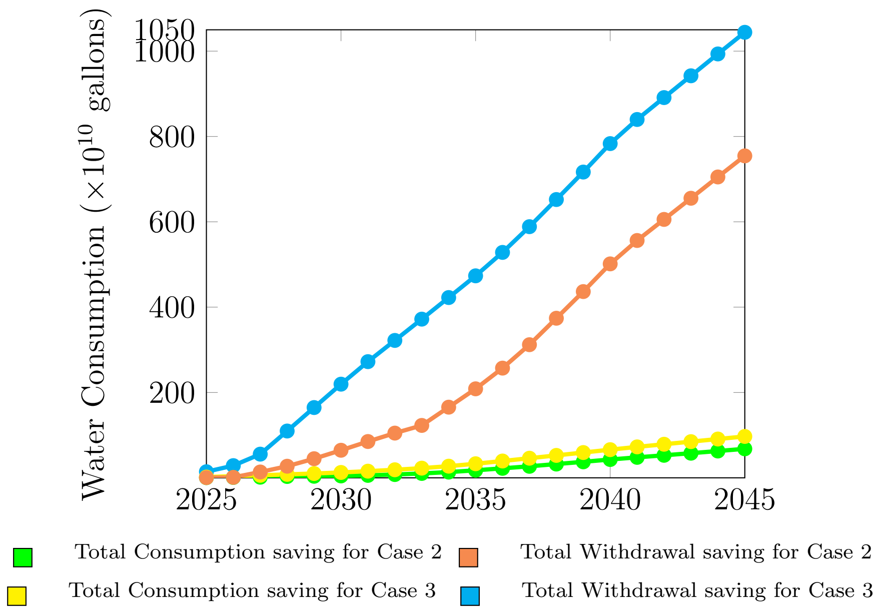

Figure 9: Cumulative Water Saving for cases 2 and 3

Table 8: Simulation Results for Renewable Integration

	Case No		
	Case 1	**Case 2**	**Case 3**
Region	New Installed Cap. (MW)		
All	77830	78020	77950
Region	New Installed CC Wet-Cooled Cap.(MW)		
All	31680	13440	4800
Region	New Installed CC Dry-Cooled Cap.(MW)		
All	0	18240	25920
Region	New Installed OC Cap.(MW)		
All	22720	26240	26880
Region	New Installed Renewable Cap.(MW)		
All	20550	20100	20350
	Cost (billion $)		
Total Cost	126.67	131.52	136.66
Capital Cost	47.3	47.74	48.75
Fuel Cost	76.13	80.52	84.57
Execution Time (sec)	435	695	116

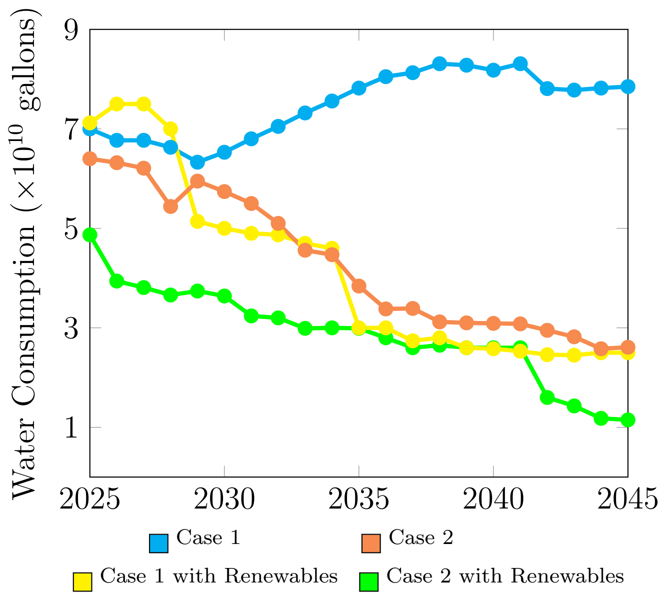

Figure 10: Yearly water consumption under renewable integration

for withdrawal purpose is very limited and from year 2031, the generation technologies and cooling systems are selected such that the amount of water withdraw is reduced to zero. For better clarification, the total saving in water consumption and withdraw is illustrated In Fig. 9. In Fig. 9, the cumulative total amount of water saving in Case 2 and Case 3 with respect to Case 1 has been illustrated for Region 2 and Region 3. The total saving of water consumption in Case 3 with respect to Case 1 during 21-years planning horizon is near to 3.7×10^9 m^3, approximately equal to the water consumption of Tehran city for 3 years.

5.4. Renewable Integration Scenario

The integration of renewable resources including wind and solar power is an attractive solution especially to achieve the environmental targets. Conventionally, the renewable units are integrated in modern power systems due to their impact on carbon emission reduction. However, the water consumption and withdrawal of renewable resources including wind and solar power is negligible. Therefore, the impact of renewable integration on water saving and generation mix is investigated in this section. The data of candidate renewable units including their maximum penetration at each year is given in Table 5 and Table 6. It is noted that the renewable units are assumed as candidate technologies and the proposed LW-GEP model will determine the optimal size, type, and installation time of required renewable technologies. In first part of this section, all previous Case studies are repeated with renewable integration. The results of generation expansion plans and the corresponding costs are reported in Table 8. According to Table 8, the total planning cost under the renewable integration scenario is reduced by about $5 billion, compared to the corresponding cases without renewable integration. The saving in the total cost is partly due to the lack of fuel cost in renewable integration scenario. In order to fully investigate the impact of the renewable integration on the total water consumption, cases 1 and 2 are repeated with renewable integration. However, unlike the first part, it is assumed that the total planning cost can be increased to the values obtained from the corresponding cases without renewable integration (as given in Table 7). The obtained results including the yearly water consumption of Case 1 and Case 2 are illustrated in Fig. 10 with and without the renewable integration. According to Fig. 10, the total volume of water saving during the planning horizon for Case 1 and Case 2 under renewable integration scenario are 7×10^{11} and 2.9×10^{11} gallons, respectively. It can be seen that the renewable integration results in a considerable reduction in water consumption. It is concluded that the renewable integration resulted in capital cost reduction and water saving. The contribution of renewable resources in capacity constraint at peak load conditions comes up with uncertainty [37]. The results of LW-GEP model under different levels of renewable contributions are given in Table 9. It can be seen that by reducing the contribution of renewable resources from 100% to 40%, at peak load condition, the share of renewable capacity is decreased from 20350 MW to 650 MW. For example, when the contribution level is 40 %, it means that the maximum generated power of renewable units is 40 % of their nominal capacities. Please note that this is different from the capacity factors that have been defined and used (as were given in Table 3) in power balance constraint. The LW-GEP is assumed as in Case 3.

6. Conclusion

A long term water constrained generation expansion planning model was presented to determine the type, size, capacity and cooling system of the generation technologies with considering a vast range of technical, economical

Table 9: The Results Under Various Renewable Capacity Contributions

	Renewable Capacity Contribution		
	100 %	60 %	40 %
	New Installed Cap. (MW)		
Non-Renewable Units	57600	74560	85120
Renewable Units	20350	13250	650
	Cost (billion $)		
Total Cost	136.6	140	141

and water availability constraints. The proposed model was simulated over a large scale test system with different candidate generation technologies. The major findings of this research are summarized as follows. 1) Since the cooling systems have great impacts on the efficiency of generating units, the constraints of water consumption and withdrawal impact the generation mix significantly. 2) Considering regional water limits, the dry-cooled and open cycle units are proper technologies for generation expansion planning. According to the obtained results, the new installed capacity of Wet-Cooled Combined-Cycle units reduces from 55680 MW in conventional GEP model (i.e. GEP model without water constraints or Case 1) to 10560 MW in LW-GEP model (i.e. GEP model with water constraints in Case 3). Also the new installed capacity of Dry-Cooled Combined-Cycle units increases from zero MW in conventional GEP model (i.e. GEP model without water constraints or Case 1) to 38400 MW in LW-GEP model (i.e. GEP model with water constraints in Case 3) which can be interpreted as a significant change in generation mix. The new installed capacity of Open-Cycle units increases from 29600 MW in conventional GEP model (i.e. GEP model without water constraints or Case 1) to 36480 MW in LW-GEP model (i.e. GEP model with water constraints in Case 3). 3) The total costs of generation expansion problem increases under water stress conditions. This is due to switching to dry-cooled system with higher capital cost and lower efficiency. According to the simulation results, the total planning cost is increased from 131.77 billion $ in conventional GEP model (i.e. Case 1) to 140.85 billion $ in LW-GEP model (i.e. Case 3). 4) The integration of renewable resources results in reduction of planning cost and more water saving. Uncertainties in water availability and renewable generation affects the generation mix and can be addressed in future works. As another potential future work, a comprehensive GEP model can be developed to minimize the cost of investment decisions, the amount of air pollution, and water use targets, simultaneously, via a multi-objective optimization method such as Pareto theory.

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