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MEJIA GIRALDO, DIEGO ADOLFO; LOPEZ LEZAMA, JESUS MARIA; GALLEGO PAREJA, LUIS ALFONSO

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MODELO DE PLANEAMIENTO DE LA EXPANSIÓN DE LA GENERACIÓN CONSIDERANDO RESTRICCIONES DE EMISIONES

DIEGO ADOLFO MEJIA GIRALDO
M.Sc. Ing. Eléctrica, profesor auxiliar Universidad de Antioquia, diegomej@udea.edu.co

JESUS MARIA LOPEZ LEZAMA
M.Sc. Ing. Eléctrica, profesor auxiliar Universidad de Antioquia, lezama@udea.edu.co

LUIS ALFONSO GALLEGO PAREJA
Ph.D. Ing. Eléctrica, Universidad Estadual Paulista, gallegopareja@gmail.com

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ABSTRACT: The generation expansion planning (GEP) problem consists in determining the type of technology, size, location and time at which new generation units must be integrated to the system, over a given planning horizon, to satisfy the forecasted energy demand. Over the past few years, due to an increasing awareness of environmental issues, different approaches to solve the GEP problem have included some sort of environmental policy, typically based on emission constraints. This paper presents a linear model in a dynamic version to solve the GEP problem. The main difference between the proposed model and most of the works presented in the specialized literature is the way the environmental policy is envisaged. Such policy includes: i) the taxation of CO_2 emissions, ii) an annual Emissions Reduction Rate (ERR) in the overall system, and iii) the gradual retirement of old inefficient generation plants. The proposed model is applied in an 11-region to design the most cost-effective and sustainable 10-technology US energy portfolio for the next 20 years.

KEYWORDS: Generation expansion planning, reduction of CO_2 emissions, linear programming.

RESUMEN: El problema de expansión de la generación consiste en determinar el tipo de tecnología, dimensionamiento, ubicación y momento en el cual nuevas plantas de generación deben ser integradas al sistema, en un horizonte de planeamiento dado, para satisfacer la demanda de energía pronosticada. En los últimos años, debido a un creciente interés en asuntos medioambientales, varias metodologías para resolver el problema de expansión de la generación han incluido algún tipo de política medioambiental, típicamente basada en restricciones de emisiones. Este artículo presenta un modelo lineal en una versión dinámica para resolver el problema de planeamiento de expansión de la generación. La principal diferencia entre el modelo propuesto y la mayoría de los trabajos presentados en la literatura especializada es la forma en que la política medioambiental ha sido contemplada. Tal política incluye: i) impuestos sobre las emisiones de CO_2, ii) una reducción anual de emisiones en todo el sistema y iii) el retiro gradual de plantas de generación ineficientes. El modelo propuesto ha sido aplicado al caso de expansión de los Estados Unidos para encontrar el portafolio de energía más rentable y sostenible en los próximos 20 años, considerando 11 regiones y 10 tipos diferentes de tecnología.

PALABRAS CLAVE: Planeamiento de la expansión de la generación, reducción de emisiones de CO_2, programación lineal.

1. INTRODUCTION

The growth of the countries implies a growth in the electric energy consumption within their inhabitants. Industrialized countries, for example, have to frequently look for the most likely future scenario in terms of energy consumption or demand. However, estimating what the demand is going to be is not the only problem. Perhaps, the arising question to be answered is how the central authority is planning to meet the demand growth. Then, the central authority has to develop a smart plan over the time in order to satisfy the increasing energy requirements of the population. Such a plan not only should deal with how much energy the electric power system has to offer for the next years, but also with the way those energy resources will be obtained. The physical constraints of the real world, environmental issues, scarcity of resources, and the high cost of new type of energies, make the planning problem a very difficult task [1].

The Generation Expansion Planning (GEP) problem consists in determining the ideal technology, expansion size, sitting, and timing of construction of new plant capacity in an economic fashion over the long planning horizon, ensuring that installed capacity adequately meets the projected demand growth [2]. The GEP is a highly constrained, nonlinear, discrete optimization problem. Several optimization methods have been used to solve this problem. Some of the emerging techniques applied to solve the GEP problem are reviewed in [3]. The application of the Benders decomposition technique to solve the GEP and transmission planning problem has been reported in [4] and [5]. Some examples of Genetic Algorithms applied solve the GEP problem are found in [6] and [7]. In [8], the GEP problem is modeled as a mixed integer linear programming problem, and to solve this problem, a combination of Bender decomposition and Genetic Algorithms was implemented. In a few papers the GEP problem is treated as a multi-objective problem, and conventional techniques have been applied to solve it [9].

In [10] and [11] the GEP problem is solved using an elitist Nondominated Sorting Genetic Algorithm (NSGA-II) for a single-objective and multi-objective approach, respectively.
In [12] an integrated power generation expansion planning model is proposed. To account for emissions constraints, caps were imposed on tradable CO_2 allowance.

This paper proposes an optimization-based decision-making model for power systems planning. It includes aspects related to economical issues, the recent situation in terms of new taxes for CO_2 emissions, the growth in demand, and the technical aspects of energy production technologies.
The GEP problem has been formulated as a linear optimization problem in a dynamic version. That is, there are some periods over the horizon where some decisions/control-actions are taken in order to achieve the total objective. Not all of the investments are necessarily to be made at the beginning of the horizon plan because some of the current infrastructure might be required to gradually retire from the system. To obtain a good planning strategy, the total cost of the project is calculated as the sum of the net present value of the costs related to investment, operation and maintenance, fuel and CO_2 emissions. In addition, some constraints are imposed to the model such as demand supply, CO_2 yearly emissions reduction, retirement of old inefficient plants according to their lifetime, minimum capacity reserve, and maximum annual generation allowed to be installed. Also, the availability of resources depends on the geographical location of the future generation power plant. Therefore, the final plan response must provide with the new generation park for every region throughout the horizon plan that satisfies all of the constraints in the most economical fashion.

2. PROBLEM FORMULATION

As mentioned above, the GEP problem can be stated as a problem of finding the most efficient long-run energy portfolio in terms of cost, reliability, and sustainability. The proposed model presented in this paper consists of a centralized planning program. The objective function and the constraints of the problem are explained below.

2.1 Objective function

The objective function is presented in equation (1) and consists on the minimization of the total costs that includes five components: a) investment cost, b) retirement of old plants, c) operation and maintenance cost, d) fuel cost and e) CO_2 emissions cost.

$$\underset{G_{i,j,t},G_{i,j,t}^{inj},G_{i,j,t}^{ret}}{Min} (1+r)^{-t}\sum_{t=0}^{T-1}\sum_{i\in\psi}\sum_{j\in\Omega}\Big\{ I_j G_{i,j}^{inj}(t) + R_j G_{i,j}^{inj}(t) + OM_j CF_j G_{i,j}(t)\Delta t + Fuel_{ij}(t)\frac{3.41}{n_j}CF_j G_{i,j}(t)\Delta t + Tax_{CO2}(t) E_j CF_j G_{i,j}(t)\Delta t \Big\} \quad (1)$$

Where:

ψ : Set of existing regions available for planning.

Ω : Set of generation technologies available for planning.

T : Horizon plan: [years].

$G_{i,j}(t)$: Net generation capacity of technology j installed at the beginning of the year t.

$G_{i,j}^{inj}(t)$: Generation capacity of technology j to be installed during year t at region i: [MW].

$G_{i,j}^{ret}(t)$: Generation capacity of technology j to be retired during the year t at region i.

Δt : Period duration (number of hours per year).

r : Annual discount rate: [%].

I_j : Investment cost of building a plant of technology j: [\$/MW].

R_j : Retirement Cost of plant of technology j:[\$/MW].

OM_j : Operation and maintenance cost of plant of technology j: [\$/MWh].

$Fuel_{i,j}(t)$: Fuel cost of technology j at region i during year t: [\$/MBTU].

$Tax_{CO2}(t)$: CO_2 Emission tax during year t: [\$/lbCO_2].

CF_j : Capacity factor of a plant of technology j: [%].

n_j : Efficiency of a plant of technology j: [%].

E_j : CO_2 Emissions factor of a plant of technology j: [lbCO_2/MWh].

2.2 Net power balance

The net power must be updated at the beginning of each year (as shown in equation (2)) having into account the new power injection that comes in and the "old" power retirement that comes out. It is assumed that the power $G_{i,j,t}$ is constant during year t.

$$G_{i,j}(t+1) = G_{i,j}(t) + G_{i,j}^{inj}(t) - G_{i,j}^{ret}(t); \quad \forall i\in\psi, \quad \forall j\in\Omega, \quad \forall t = 0,...,T-1 \quad (2)$$

The initial condition is expressed in equation (3) as follows:

$$G_{i,j}(0) = G_{i,j}^{existing}, \quad \forall i\in\psi, \quad \forall j\in\Omega \quad (3)$$

Where:

$G_{i,j}^{existing}$: Actual installed power of technology j at region i [MW].

2.3 Retirement of old plants

As every plant holds a lifetime, it is necessary to consider the retirement of old plants. Therefore, an investment in generation capacity made in the year t is valid only until the t+*life* year as expressed in equation (4).

$$G_{i,j}^{ret}(t+life_j) = G_{i,j}^{\text{int}}(t) \quad \forall i\in\psi, \forall j\in\Omega, \forall t = 0,...,T-1 \quad (4)$$

Where:

$Life_j$: Lifetime of a power plant of technology j: [years].

2.4 Limits on available energy resources

In addition to the requirement of the capacities to be positive, the GEP has to consider the maximum available energy resources for each year at every region. The maximum availability of resources is expressed in MW, and can be considered as the amount of a specific resource such as: oil, coal, natural gas, uranium, water, wind, etc. The proposed formulation considers resource availability per region. Every geographical region has a different energy resource potential. The constraints expressing the availability of energy resources per region are given by the set of equations (5).

$$\begin{aligned} & 0 \leq G_{i,j}(t) \leq G_{i,j}^{\max}(t), \\ & G_{i,j}^{inj}(t) \geq 0, \\ & G_{i,j}^{ret}(t) \geq 0, \\ & \forall i \in \psi, \forall j \in \Omega, \forall t = 0,...,T-1 \end{aligned} \quad (5)$$

Where:

$G_{i,j}^{\max}(t)$: Maximum total capacity of technology j to be operating during year t at region i: [MW].

2.5 Demand balance and capacity reserve

The constraint associated with demand balance guarantees that in every region there will be enough generation capacity to meet the expected demand growth. In addition to this generation there must be a minimum capacity reserve. This reserve guarantees the security and reliability of the system in case of generator outages; however, it also carries out a cost. Therefore there is a tradeoff between reliability and cost, the safer the system (more reserve), the more costly the plan is going to be. For some plants like wind farms (also solar), it is necessary to set a capacity credit that measures the "firm" capacity of the plant. This issue arises when actual output of a power plant is significantly less than its rated capacity due to low availability of resources (specially wind power). The set of constraints for minimum reserve requirement are expressed in equations (6) and (7).

$$\begin{aligned} & \sum_{j \in \Omega} Cr_{i,j} G_{i,j}(t) \geq D(t)(1 + \mathrm{Re}\, s_i / 100) \\ & \forall i \in \psi, \quad \forall t = 0,...,T-1 \end{aligned} \quad (6)$$

$$\begin{aligned} & D(t+1) = (1 + LGR/100) D(t) \\ & \forall t = 0,...,T-1 \end{aligned} \quad (7)$$

Where:

$D(t)$: System load during the year t:[MW].

$\mathrm{Re}\, s_i$: Minimum capacity reserve: [%].

LGR: Annual load growth rate: [%].

An important fact to consider is that under no power transmission system, every region must satisfy a minimum capacity reserve for security reasons (security refers to the possibility of attending the power demand under unexpected contingency situations). However, if transmission lines between regions are incorporated and modeled in the planning process, this regional requirement could be avoided in some cases. The reason is that transmission lines would allow the interconnected regions to share the most efficient energetic resources. As a result, the GEP problem might be more economical. Nevertheless, a global minimum capacity reserve margin has to be allocated to the system for reliability reasons.

2.6 CO_2 Emissions reduction

In order to incorporate realistic environmental situations, an emission reduction constraint is added to the formulation. The objective is to reduce the CO_2 emissions in the operation of the new power system. This situation is represented by equation (8). And constraint (9) imposes a limit on the yearly CO_2 emissions. These limits are based on an annual Emissions Reduction Rate (ERR) which guarantees a cleaner electricity production year by year.

$$\begin{aligned} & \frac{1}{2.204 x 10^9} \sum_{i \in \psi} \sum_{j \in \Omega} E_j CF_j G_{i,j}(t) \Delta t \leq E_{CO_2}^{\max}(t) \\ & \forall t = 0,...,T-1 \end{aligned} \quad (8)$$

$$\begin{aligned} & E_{CO_2}^{\max}(t+1) = (1 - ERR/100) E_{CO_2}^{\max}(t) \\ & \forall t = 0,...,T-1 \end{aligned} \quad (9)$$

Where:

$E_{CO_2}^{\max}(0) = E_{CO_2,current}^{\max}$

$E_{CO_2}^{\max}(t)$: Maximum allowed amount of carbon dioxide emissions: [MMT CO_2e/year = Million Metric Tons of CO_2 per year].

ERR: Annual Emissions Reduction Rate: [%].

$E^{max}_{CO_2,current}$: Current annual level of CO_2 emissions: [MMT CO2e/year].

The left side of the emission limits inequality constraint represents the total CO_2 emissions per year. The constant multiplying the sum is a conversion factor.

3. OPTIMIZATION (A DUAL PROBLEM)

The GEP problem represents a dynamical system where some inputs have to be applied in order to satisfy some criteria. Thus, the GEP problem can be understood as an optimal control problem. The control signals are the new added power capacity and the plant retirements. With these two sets of variables, the overall system can be controlled in a determined fashion.

With the aim of illustrating the importance of the dual problem for planning, let us consider a simplified planning problem with one region, one year as the horizon plan, and two types of technologies. So, the idea is to minimize the investment cost plus the operation cost as expressed in (10).

$$\begin{aligned} \underset{g_1,g_2}{Min}\ Cost = {} & I_1(g_1 - g_1^{existing}) + \\ & I_2(g_2 - g_2^{existing}) + C_1(g_1) + C_2(g_2) \\ & Subject\ to: \\ & \quad g_1 + g_2 \geq (1+res)d\ (demand\ balance) \\ & \quad g_1 \leq g_1^{max} \\ & \quad g_2 \leq g_2^{max} \end{aligned} \tag{10}$$

The Lagrangean of the reduced problem is given by equation (11).

$$\begin{aligned} L(g_1, g_2, \lambda, \mu_1, \mu_2) = {} & I_1(g_1 - g_1^{existing}) + \\ & I_2(g_2 - g_2^{existing}) + C_1(g_1) + C_2(g_2) + \\ & \lambda\{(1+res_1)d_1 - g_1 - g_2\} + \mu_{1,\max}(g_1 - g_1^{\max}) \\ & + \mu_{2,\max}(g_2 - g_2^{\max}) \end{aligned} \tag{11}$$

$$With \quad \lambda,\ \mu_{1,\min},\ \mu_{2,\max} \geq 0$$

If the gradient of the Lagrangean with respect to the primal variables g_1, g_2 is matched to zero, the set of equations showed in (12) is obtained.

$$\begin{aligned} \frac{\partial L}{\partial g_1} &= I_1 + C_1 - \lambda + \mu_{1,\max} = 0 \\ \frac{\partial L}{\partial g_2} &= I_2 + C_2 - \lambda + \mu_{2,\max} = 0 \end{aligned} \tag{12}$$

Solving the above set of equations, the Lagrange multiplier λ can be expressed as shown in equation (13).

$$\lambda = I_1 + C_1 + \mu_{1,\max} = I_2 + C_2 + \mu_{2,\max} \tag{13}$$

This expression shows that the Lagrange multiplier of the demand balance equation depends on the investment cost, operation cost, and the congestion of both generators. If for example, either of the generators 1 or 2 is operating at its maximum level g_1^{max} or g_2^{max} respectively (congestion), then, by complementary slackness condition, $\mu_{1,max}$ or $\mu_{1,max}$ is greater than cero. This fact implies that under congestion, the Lagrange multiplier λ increases.

The condition for λ not to increase is that none of the generators is congested. In practical terms, it means that available resources g_1^{max} and g_2^{max} are enough to satisfy the demand and the reserve requirement.

The importance of λ is that such dual variable represents the marginal cost of increasing the demand by one unit, and this is actually the theoretical price all of the consumers would pay for electric energy. So, in order to maintain low energy prices at each of the regions in a power system, the congestion of the system has to be minimized. Nevertheless, to avoid congestion, high investments have to be done in order operate the system with certain degree of freedom (flexible system).

For a real power system, the number of buses (regions) determines the number of λ's. Thus, different geographical regions can pay different energy prices according to the production cost and congestion. In an ideal power system, the λ's should be equal to the production or marginal cost. However, that is not always the case.

4. TEST AND RESULTS

Using the previous formulation, the generation expansion planning for a 10-technology 11-region simplified US power system was simulated (see Figure 1.)

The objective is to obtain a generation expansion planning for the next 20 years that satisfies all of the constraints explained in the formulation. It is imposed to charge a \$10/MMTCO$_2$-carbon tax for the CO_2 emissions. Also, it is assumed that this value is increasing over time at a 5% annual rate. In order to obtain a reliable power system, a 15% reserve margin is imposed for all the regions. The demand is assumed to grow at a 3% growth rate. In addition, a yearly increase in fuel prices is considered with a 2% growth rate. Ten different technologies are assumed to be available for the planning problem. Tables 1 and 2 show information related to the cost of the technologies. The following nomenclature has been used:
PC: Pulverized Coal
NGCC: Natural Gas Combined Cycle
IGCC: Integrated Gasification Combined Cycle
CS: Carbon Sequestration
CT: Combustion Turbine

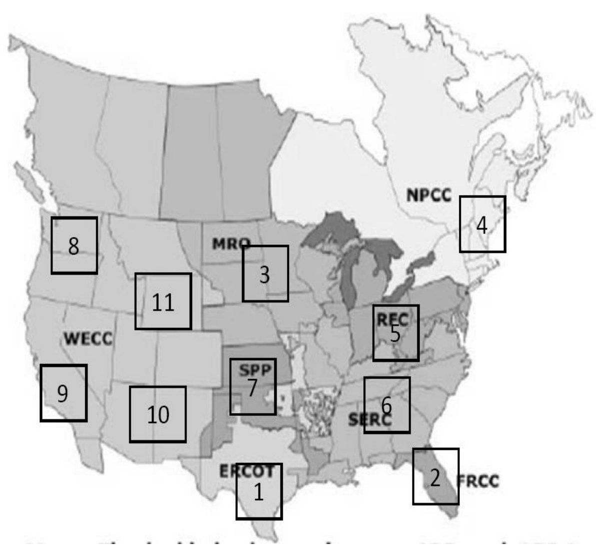

Figure 1. Considered US regions for planning

Table 1. Generation Technologies Information

Type	Investment Cost (million\$/MW)	Retirement Cost (million\$/MW)
Nuclear	2.475	0.7425
PC	1.534	0.4602
NGCC	0.706	0.2118
CT	0.5	0.15
Hydro	1	0.3
Wind	1.434	0.4302
Oil	1	0.3
IGCC	1.733	0.5199
IGCC wCS	2.537	0.7611
Solar	5.649	1.6947

Table 2. Generation Technologies Information

Type	O&M Cost (\$/MWh)	Fuel cost (\$/MBTU)
Nuclear	0.55	0.75
PC	2.95	1.85
NGCC	2.01	8
CT	1.8	
Hydro	3.41	--
Wind	0	--
Oil	2	
IGCC	2.84	1.85
IGCC wCS	4.32	1.85
Solar	0	--

Note that solar, IGCC with carbon sequestration and nuclear plants are the most expensive in capital investment. However, in terms of operation, wind and solar are the most economical. Furthermore, hydro, wind, and solar do not have fuel cost because they use natural and renewable resources as fuel. The fuels with the highest emission rate of CO_2 are coal and oil plants, being their emission rate around 170 lb-CO_2 per MBTU produced.

At t=0, the 2007 peak demand in the US was about 811 GW, and the total installed capacity was 916.25 GW. At regions 3, 5, 6, 7, 8, 10, and 11 coal-fired power plants are more predominant; and NGCC are more predominant in the rest of the regions. IGCC (with and without CS), and solar plants do not provide any capacity at t=0.

For the scenario mentioned above, a \$2.8 trillion generation plan was obtained. This cost represents the net present value of the total investment cost. Figure 2 shows how the capital is used throughout the horizon plan. As in most of the planning processes, it is usual to invest a high quantity of money at the beginning of the study period. However, in this application, an additional high investment is done around year 2018. By this time, old generation is being retired, and consequently, more new generation is required.

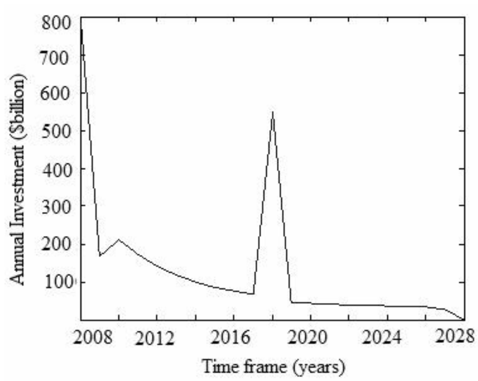

Figure 2. Annual Investment

Figure 3 shows the reduction in hydro capacity for region 3 given that the operation of nuclear and wind power in the long-run is more economical. Also, figure 4 shows how the optimal capacity of coal plants must be reduced. For oil plants, the same type of behavior is obtained for all of the regions. So, it is clear that oil and coal plants are not efficient enough as to accomplish with the economical and environmental requirements.

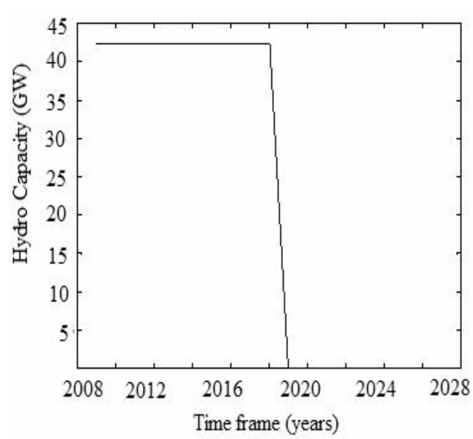

Figure 3. Hydro capacity in region 3

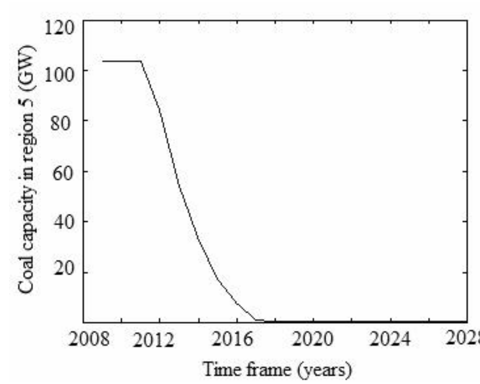

Figure 4. Coal capacity in region 5

The resulting generation plan is highly attracted by nuclear energy instead of wind. However, the nuclear waste feature was not included in the formulation. Under such a requirement, results can change. Nevertheless, many wind plants are proposed to be built. For example, figures 5 and 6 show the resulting nuclear capacity for region 6 and wind capacity for region 9 respectively.

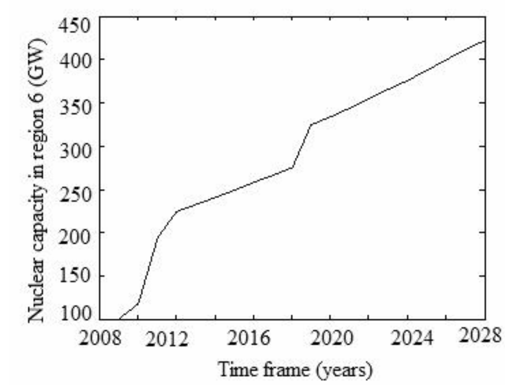

Figure 5. Nuclear capacity in region 6

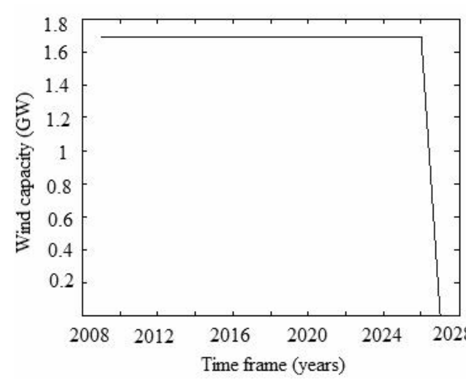

Figure 6. Wind capacity in region 9

Other technologies such as NGCC, CT, IGCC, and IGCC with Carbon Sequestration are not suggested in the planning.

Figure 7 shows the relationship between generation capacity and demand. It can be observed that the reserve margin of 15% is maintained.

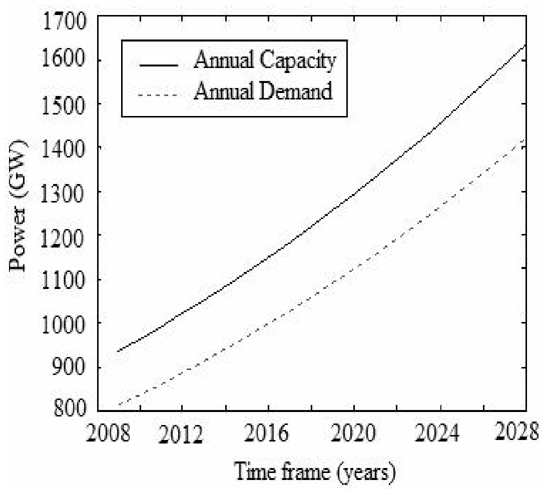

Figure 7. System generation and demand

Figure 8 shows the annual average Energy Marginal Price (EMP) (Lagrange multiplier of the system). Actually, each region holds its own dual variable for the minimum reserve constraint. However, to get an idea of what the energy marginal price is going to be, an average price for the system is calculated. At the end of the horizon plan, the price increases significantly, indicating that new investment planning is required in order to avoid extreme increase in the price. In figure 2 it can be seen that there is no investment for the year 2028. This makes sense because if there were investment in the last year, such a new generation is not used in the time frame of study; it would be used for 2029. The average marginal price is declining over the planning horizon, this suggests that under these investment decisions and environmental policy, high-fuel-price technologies (coal and NGCC) are displaced by cheaper ones.

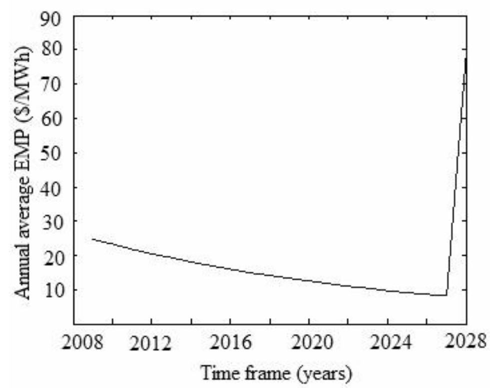

Figure 8. Average energy marginal price

Even though this price signal is theoretical since it does not reflect the profit factors generating companies are looking for, it does provide economic signals to investors and market participants that help reducing uncertainty regarding electricity price fluctuations.

Finally, figure 9 shows how the imposed limits on the constraints act effectively. The range of values shown in figure 9 coincides with real emissions in the US for 2007. The CO_2 emissions reduced notably after year 2018, which is exactly when new generation is injected to the system to replace the retirements of old and not-clean technologies.

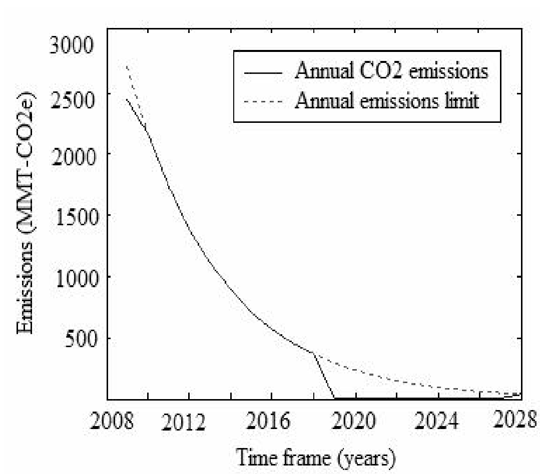

Figure 9. Annual Emissions

As it was expected, if the emissions constraint is active between 2010 and 2018 approximately, the dual variable associated with this constraint is greater than zero during the same period.

The dual variable is zero for the years the emission constraint is not active. Figure 10 shows such a behavior. This dual variable can be referred to as the marginal cost of the emissions. Apparently, one year before the 2018 investment is done, a quite significant congestion seemed to occur in the system. This seems to be a signal for new investment; the same happens at the end of the horizon plan.

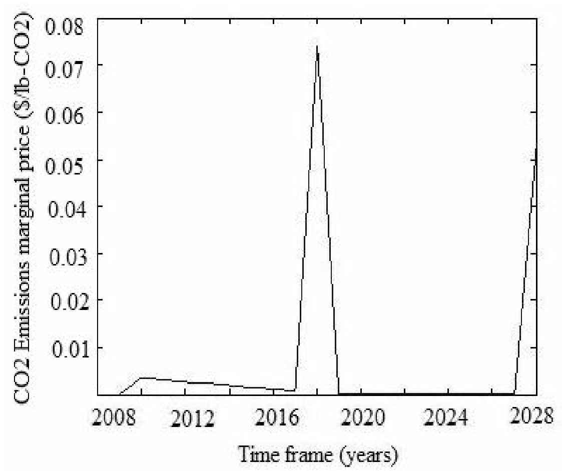

Figure 10. Dual variable of the emissions constraint

4. CONCLUSIONS

A linear model in a dynamic version was presented in this paper to solve the generation expansion planning problem. In addition to the traditional economic and technical constraints, the model considers an environmental policy consisting on the taxation of CO_2 emissions plus an annual Emissions Reduction Rate (ERR). This approach guarantees a strongly cleaner electricity production in the expanded power system at a relatively low investment cost (price of sustainability). Due to the environmental policy included in the model, highly pollutant generation technologies (such as coal and oil plants) turned out not to be attractive, and therefore were not selected in the optimization process. Further work will consider the effect of the transmission system providing a more flexible generation expansion planning model.

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