Power system capacity expansion planning model considering carbon emissions constraints

Modelo de expansión de capacidad de energía considerando restricciones de emisiones de carbono

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Abstract

This paper presents a power system capacity expansion planning model considering carbon emissions constraints. In addition to the traditional technical and economical issues usually considered in the planning process, two environmental policies that consist on the taxation and the annual limits of carbon dioxide (CO_2) emissions are considered. Furthermore, the gradual retirement of old inefficient generation plants has been included. The approach guarantees a cleaner electricity production in the expanded power system at a relatively low cost. The proposed model considers the transmission system and is applied to a 4-region and 11-region power systems over a 20-year planning horizon. Results show practical investment decisions in terms of sustainability and costs.

----- *Keywords*: Capacity expansion planning, carbon dioxide emissions, capacity factor, sustainability

Resumen

Este artículo presenta un modelo de planeamiento de expansión de la capacidad de sistemas de potencia considerando restricciones en emisiones de carbono. Además de los aspectos técnicos y económicos considerados usualmente

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en el proceso de planeamiento, se consideran dos políticas ambientales que consisten en el cobro de un impuesto y un límite anual a las emisiones de dióxido de carbono (CO_2). Adicionalmente se ha incluido el retiro gradual de las plantas de generación ineficientes. Este abordaje garantiza una producción de electricidad más limpia en el sistema expandido a un costo relativamente bajo. El modelo propuesto considera la red de transmisión y es aplicado a un sistema de potencia de prueba de 4 regiones y a uno de 11 regiones para un horizonte de planeación de 20 años. Los resultados muestran decisiones de inversión prácticas en términos de sostenibilidad y costos.

----- *Palabras clave:* Planeamiento de la expansión de la generación, reducción de emisiones de CO_2, factor de capacidad, sustentabilidad

Introduction

The Generation Expansion Planning (GEP) problem consists in determining the optimal type of technology, expansion size, sitting, and timing of construction of new power capacity minimizing the investment plus the operational cost of the system over the long planning horizon, ensuring that installed capacity adequately meets projected demand growth [1]. In general, 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 [2]. The application of decomposition techniques to solve the GEP and transmission planning problem has been reported in [3-5]. Some examples of Genetic Algorithms applied solve the GEP problem are found in [6, 7]. In a few papers the GEP problem is treated as a multi-objective problem. Ceciliano et al. [8] propose a multiobjective GEP approach to minimize costs, environmental impact (carbon emissions), imported fuel and fuel price risks. Hobbs [9] presents some optimization methods for electric utility resource planning. Also, market environment simulations were proposed in [10] for developing transmission and capacity expansion planning. Roy et al. [11] add transmission security constraints in a resource planning problem where multiple generation companies interact themselves and with the Independent System Operator (ISO). In [12] an integrated GEP model towards low-carbon economy is proposed. To account for emissions constraints caps were imposed on tradable CO_2 allowance. In [13] the reduction of emissions is included as an objective function under multi-objective optimization scheme. In [14, 15] the GEP problem is solved using an elitist Nondominated Sorting GA (NSGA-II) for a single and multi-objective approach, respectively; however, no emission constraints are considered. This paper proposes a minimum-cost dynamic GEP formulation. The main difference between the proposed approach and most GEP formulations presented in the literature consists in the way emissions constraints are accounted for. In this case we not only consider a cap on yearly carbon emissions, but also impose a carbon tax, and model the retirement of old inefficient generating plants. Furthermore we also consider the transmission network. Consequently, optimal capacity will not be necessarily installed near load spots. Generally speaking, big load centers likely need energy transportation mechanisms to get access to energy produced by technologies located far away. Traditionally, thermal plants are located close to the load because fuels can be transported. However, that is not the case when energy is produced by renewable resources like hydropower, wind, or solar, because their “fuel” cannot be shipped. Thus, a reasonable thinking suggests using transmission lines when new facilities are to be built at locations where transmission system has not accessed.

Problem formulation

Objective function

The objective function presented in equation (1) describes the total planning cost. The first two terms represent the cost of investment and retirement of old plants. The other terms represent the cost of: a) operation and maintenance b) fuel, c) CO_2 emissions and d) non-served demand.

$$\underset{Cap_{i,j,t},G_{i,j,t}^{add},P_{i,j,m,t}}{\text{minimize}} \quad Total\ Cost$$

$$\begin{aligned} &= (1+r)^{-t}\left\{ \sum_{t=0}^{T-1}\sum_{i\in\Psi}\sum_{j\in\Omega} I_j G_{i,j,t}^{add} + \sum_{t=0}^{T-1}\sum_{i\in\Psi}\sum_{j\in\Omega} R_j G_{i,j,t}^{ret} \right. \\ &+ \sum_{t=0}^{T}\sum_{i\in\Psi}\sum_{j\in\Omega}\sum_{m\in\mathrm{M}} OM_j P_{i,j,m,t}\Delta t_m \\ &+ \sum_{t=0}^{T}\sum_{i\in\Psi}\sum_{j\in\Omega}\sum_{m\in\mathrm{M}} Fuel_{i,j,t} HR_j P_{i,j,m,t}\Delta t_m \\ &+ \sum_{t=1}^{T}\sum_{i\in\Psi}\sum_{j\in\Omega}\sum_{m\in\mathrm{M}} Tax_{CO_2,t} E_j HR_j P_{i,j,m,t}\Delta t_m \\ &\left. + \rho_{DNS}\sum_{t=0}^{T}\sum_{i\in\Psi}\sum_{m\in\mathrm{M}} DNS_{i,m,t}\Delta t_m \right\} \end{aligned} \tag{1}$$

Where Ψ and Ω are the set of existing regions and generation technologies available for planning, respectively; T is the horizon plan in years; M is the set of load duration curve modes; $Cap_{i,j,t}$ is the net generation capacity of technology j installed at the beginning of the year t at bus i, in MW; $G_{i,j,t}^{add}$ and $G_{i,j,t}^{ret}$ are the generation capacity addition and retirement of technology j installed during year t at bus i in MW, respectively; $P_{i,j,m,t}$ is the total m-mode generated power by all technology-j plants operating during year t at bus i, in MW; $DNS_{i,m,t}$ is the total m-mode non-served demand during year t at bus i, in MW; Δt_m is the duration of m -mode load, in hours; r is the Annual Discount Rate, in percentage; I_j and R_j are the cost of building and retirement of a technology-j plant, in \$/MW, respectively; OM_j is the operation and maintenance cost of a technology-j plant, in \$/MWh; $Fuel_{i,j,t}$ is the fuel cost of a technology-j plant at bus i during year t, in \$/MBTU; $T_{axco2/t}$ is the CO_2 emission tax during year t, in \$/lbCO_2; HR_j is the nominal heat rate of a technology-j plant, in percentage; E_j is the CO_2 Emissions Factor of a technology-$j$plant, in lbCO_2/MWh; and finally, P_{DNS} is the non-served demand penalty cost, in \$/MWh.

Net power balance

Additions and retirements of capacity determine how much network capacity the system has every year. The assumption made in this model is that a capacity addition is available one-year ahead. Equation (2) is an inventory constraint, used in problems where some kind of storage is considered.

$$Cap_{i,j,t} = Cap_{i,j,t-1} + G_{i,j,t-1}^{add} - G_{i,j,t-1}^{ret}, \quad \forall i \in \Psi, \quad \forall j \in \Omega, \quad \forall t = 1, \dots, T \tag{2}$$

Where $Cap_{i,j,t}$ is the output power limit for the OPF problem in every period. Equation (3) states the initial condition, which allocates the initial installed capacity split up by type of technology and bus:

$$Cap_{i,j,0} = G_{i,j}^{existing}, \quad \forall i \in \Psi, \quad \forall j \in \Omega \tag{3}$$

Where $G_{i,j}^{existing}$ corresponds to the actual installed power of technology j at region i, in MW. Additionally, it is necessary to establish that capacity additions are positive, as expressed by equation (4).

$$G_{i,j,t}^{add} \geq 0, \ \forall i \in \Psi, \ \forall j \in \Omega, \ \forall t = 0, \dots, T-1 \tag{4}$$

Retirement of generation units

When a generation unit reaches its lifetime, most of the times, it becomes obsolete and inefficient. One of the contributions of this paper is the modeling of the retirement of such old inefficient generating plants. Then, once a generation unit reaches its lifetime a new investment is allowed to be made at the same place. Equation (5) shows the relationship between additions and retirements of capacity. Where $Life_j$ is the lifetime of a power plant of technology j, in years.

$$G_{i,j,t+Life_j}^{ret} = G_{i,j,t}^{add}, \quad \forall i \in \Psi, \quad \forall j \in \Omega, \quad \forall t = 0, \dots, T-1 \tag{5}$$

Maximum capacity factor

The capacity factor of a power plant measures the actual energy produced as a percentage of the maximum energy the unit can produce in a specific period. Equation (6) establishes the maximum achievable capacity factor at each location for each technology.

$$\sum_{m \in \mathrm{M}} P_{i,j,m,t} \Delta t_m \leq CF_{i,j} Cap_{i,j,t} \sum_{m \in \mathrm{M}} \Delta t_m \ , \quad \forall i \in \Psi, \quad \forall j \in \Omega, \quad \forall t = 1, \dots, T \tag{6}$$

Where $CF_{i,j}$ is the maximum annual technology-j-unit capacity factor to be operating at region i, in MW.

Capacity reserve

Capacity reserve is defined as extra capacity over the peak load expressed as a percentage. The percentage that translates nominal capacity into firm or reliable contribution of capacity is defined as *capacity credit*. The system reserve constraints that consider capacity credits for different technologies are shown in equations (7) and (8):

$$\sum_{i\in\Psi}\sum_{j\in\Omega} Credit_j Cap_{i,j,t} \geq \sum_{i\in\Psi}(1+Res/100)D_{i,peak,t}, \quad \forall t=1,\dots,T \tag{7}$$

$$D_{i,peak,t+1} = \left(1+{}^{LGR}/_{100}\right)D_{i,peak,t}, \qquad \forall t=0,\dots,T-1 \tag{8}$$

Where $Credit_j$ is the capacity credit of technology j, in percentage; $D_{i,peak,t}$ is the peak system load at bus i during the year t, in MW; Res is the minimum capacity reserve, in percentage; and LGR is the annual load growth rate, in percentage.

Maximum production constraints

Every unit's production must be less than the available capacity, which is approximately calculated as the availability, computed as the complement of Forced Outage Rate (FOR) times the actual installed capacity. The resulting constraint, shown in equation (9), counts in some fashion the associated uncertainty related to component failures:

$$0 \leq P_{i,j,m,t} \leq \left(1-{}^{FOR_j}/_{100}\right)Cap_{i,j,t}, \qquad \forall i\in\Psi, \qquad \forall j\in\Omega, \qquad \forall m\in \mathrm{M}, \qquad \forall t=0,\dots,T \tag{9}$$

Where FOR_j is the technology-j plant Forced Outage Rate, in percentage.

Transmission system model

A simplified version of an optimal DC power flow model is included. Here, power flows are modeled as independent of nodal angles. Then, the nodal balance constraint is represented by equations (10) and (11) as follows:

$$\sum_{j\in\Omega} P_{i,j,m,t} - \sum_{k\in\Xi} a_{i,k} f_{k,m,t} + DNS_{i,m,t} \geq D_{i,m,t}, \text{ with } DNS_{i,m,t}\geq 0, \qquad \forall i\in\Psi, \qquad \forall m\in \mathrm{M}, \qquad \forall t=0,\dots,T \tag{10}$$

$$\left|f_{k,m,t}\right| \leq f_k^{max}, \qquad \forall k\in\Xi, \qquad \forall m\in \mathrm{M}, \qquad \forall t=0,\dots,T \tag{11}$$

Where Ξ is the set of branches; $D_{i,m.t}$ is the mode-m load at bus i during year t, in MW; $a_{i,k}$ is the i,k-th element of the bus-branch incidence matrix; $f_{k,m,t}$ is the mode-m power flow through branch k, in MW; and $f_k^{\max}$ is the maximum permitted power flow through branch k in MW.

CO_2 Emissions reduction

In order to incorporate realistic environmental actions, an emission reduction constraint is added to the formulation. With this constraint, it is expected to reduce the CO_2 emissions level in the operation of the expanded power system. Basically, equations (12) and (13) impose regional limits on the annual CO_2 emissions, which are expressed as a yearly continuous reduction of the current level of emissions by imposing an annual Emissions Reduction Rate (ERR). The current level of regional CO_2 emissions is calculated with the operation of the power system during year zero with the initial existing capacity.

$$\frac{1}{2.204\times 10^{9}}\sum_{j\in\Omega}\sum_{m\in\mathrm{M}} E_j HR_j P_{i,j,m,t}\Delta t_m \le E^{max}_{CO_2 i,t}, \qquad \forall i\in\Psi,\ \forall t=1,\dots,T \tag{12}$$

$$E^{max}_{CO_2 i,t} = \left(1 - {}^{ERR}\!/_{100}\right) E^{max}_{CO_2 i,t-1}, \qquad \forall t=1,\dots,T \tag{13}$$

The current ($t = 0$) regional CO_2 emissions level is given by equation (14):

$$E^{max}_{CO_2 i,0} = \frac{1}{2.204\times 10^{9}}\sum_{j\in\Omega}\sum_{m\in\mathrm{M}} E_j H_j P_{i,j,m,0}\Delta t_m\,, \qquad \forall i\in\Psi \tag{14}$$

Where $E^{\max}_{CO_2 i,0}$ is the current amount of carbon emissions at bus i in MMeT (Million Metric Tons of CO_2); *ERR* is the annual emissions reduction rate, in percentage; and $E^{\max}_{CO_2 i,t}$ is the maximum amount of CO_2 emissions at bus i in year t, in MMeT. The constant $2.204\text{x}10^9$ is the number of lb in a MMeT. The product $E_j HR_j$ over the left-hand side of (12) determines the amount of carbon dioxide emitted by producing 1MWh with a technology-*j* plant.

Test and results

The Generation expansion planning problem described in this paper is represented as a standard Linear Programming problem, and as such, it is solvable using commercial optimization solvers.

A capacity expansion planning that considers an existing transmission system is performed for the system shown in figure 1. At the beginning of the planning period, it is assumed that the system has nuclear (N), coal (C), and natural gas combined cycle (NGCC) installed capacity. The planning considers the possibility of adding wind power (WND) and retiring any capacity when a unit reaches its lifetime.

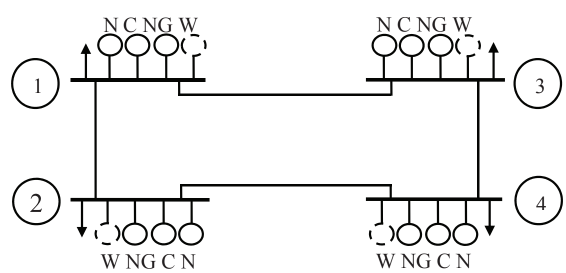

Figure 1 Four-region test system

The total initial power capacity is 2,000MW, 1,700MW, 5,000MW, and 4,500MW for regions 1, 2, 3, and 4 respectively. Technologies data are provided in table 1. As regards demand parameterization the operational problem is modeled through a 3-mode LDC for each region in which mode 1 represents a 1752-hour peak-load period, mode 2 a 2628-hour medium-load period, and mode 3 a 4380-hour base-load period. Medium and base loads are formulated as 70% and 45% of peak load respectively. Initial peak demand is 3,800MW, 3,300MW, 2,500MW, and 2,500MW for regions 1, 2, 3, and 4 respectively. For each mode of the LDC, an annual demand growth rate of 3% is assumed.

Table 1 Tecnologies data

	N	*C*	*NGCC*	*WND*
I ($million/MW)	2.48	1.53	0.71	1.43
OM ($/MWh)	0.55	2.95	1.95	2.05
HR (MBTU/MWh)	10.4	9.2	7.5	0.0
E (lb/MBTU)	0.0	215.0	117.0	0.0
Life (years)	50	40	30	20
Existing time (years)	40	33	15	0
Average Fuel ($/MBTU)	0.7	1.9	1.9	0.0
Average CF (%)	87.7	71.8	39.3	20.5
Credit (%)	90	100	90	15

Geographic dependencies

In terms of fuel costs, the lowest nuclear fuel costs are allocated at regions 3 and 4, whereas lower natural gas costs are at regions 1 and 2. The lowest coal cost is found at region 2, which can be interpreted as a location with enough coal production that does not need transportation to get it to the plant. Therefore, regions 2 and 3, since the fuel price standpoint, are candidates for installing natural gas and coal units. Not only does the fuel depend on location, but wind resources do as well. For this simulation, wind is assumed to be predominant in the east regions (3 and 4) of the system; then bigger wind capacity factors are allocated for those regions.

Base-case results

Initially, demand of regions 1 and 2 is greater than its respective installed capacity; whereas the opposite occurs at regions 3 and 4. Even though total installed capacity overpasses total peak demand, the transmission system plays a key role in this scenario because extra-production of energy coming from the east regions (3 and 4) must be delivered to the west regions (1 and 2). However, the optimal plan should make the decision regarding to whether to install new capacity in the west and consequently avoid high dependence on transmission capacity or not. A first analysis deals with solving the GEP problem with emission tax equal to zero and emissions limits equal to infinite. By solving the optimization problem, an investment of $26.13 billion has to be made in order to get a power system with 31.23GW of total installed capacity. It was found that even though the coal penetration level decreases at the end of the planning horizon, coal capacity is still present (26%) at the end due to the absence of any emissions constraint. As mentioned previously, an optimal plan that considers transmission system allows flexibility in the investment decisions. That is why, in this simulation, regions 2, 3 and 4 have extra capacity that not only allows meeting their demand, but also sending power to region 1. In terms of operational issues, an interesting observation of the operation of the capacity-expanded power system is that regions 2, 3, and 4 use coal, nuclear, and wind power respectively to supply the demand, and during peak load periods, such units reach their maximum available capacity. However, NGCC power is only used during peak demand periods at regions 1 and 2. Given this behavior, it seems that NGCC plants are built to satisfy the reserve requirements and to operate as peaking units. Also, taking a look at the resulting capacity factors in figure 2, we note that only NGCC units operate at very low capacity factors throughout the planning horizon. A low capacity factor means that a unit is on either during short periods or operating at very low production levels. Unlike NGCC units, nuclear and wind units operate at maximum capacity factors.

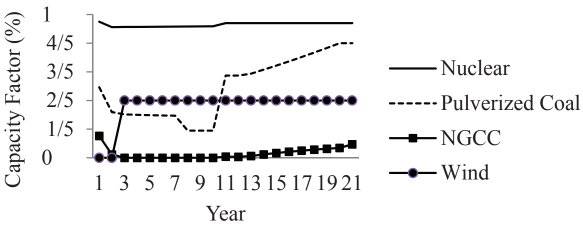

Figure 2 Technology capacity factors for the base case

As a result of the low NGCC capacity factor, power from regions 2 and 3 has to be sent to region 1 to satisfy demand, and consequently, tie lines connecting regions 1-2 and 1-3 get congested during peak-load periods; this is a clear signal for investing in transmission capacity. Another interesting observation is that during base and medium-load periods at region 4, demand is supplied basically by coal and nuclear power coming from regions 2 and 3 respectively. However, during peak-load periods, extra wind power generated at region 4 is used to meet region-3 demand; coal power from region 2 satisfies almost all of region-1 demand causing congestion in the lines connecting regions 1-2 and 3-4. In terms of annual carbon emissions, these doubled at year 20 compared to the year zero value of 26.37 MMT. Clearly, a reduction of carbon should be imposed.

Simulation results considering carbon emissions constraints

In this case, we chose an emissions tax of $1cent/lb CO_2, and an annual emissions reduction rate of 5%. As expected, different results are obtained. A difference is the previous 8GW of coal penetration at the end of the planning horizon that reduces to zero in this case (see figure 3). To supply this deficit, nuclear, wind, and NGCC power capacity are added. The investment cost is $36.1billion and the total installed capacity is 35.7GW. Therefore, the 4.4GW of "extra capacity" compared to the base-case simulation has an extra investment cost of $10 billion, or 40% of additional investment with respect to the previous simulation. So, given that the new system is "greener" than the one obtained in the base case, ensuring that price of environmental sustainability is $10 billion.

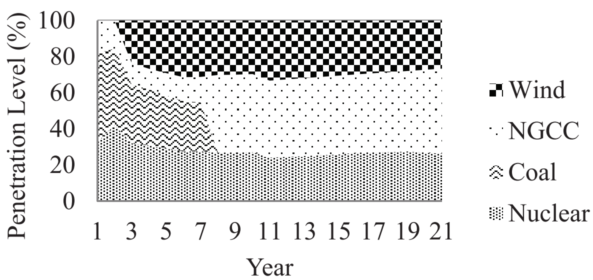

Figure 3 Penetration levels

According to figure 3, the optimal policy to face the environmental constraints is to continue using the current coal power capacity until lifetime is reached without future investments. At that moment (year 7), NGCC capacity significantly increases to cover the absence of coal power and thus it becomes the most predominant type of technology in the system. NGCC power capacity is spread throughout the system, but both nuclear and wind power capacities are not, but are localized at specific places. For example, even though nuclear units have low fuel prices at regions 3 and 4, the expansion plan suggests building nuclear capacity at regions 1 and 3, and wind at region 4 given its high potential capacity factor of 40%. As it was discussed before, region 3 was a good candidate for wind as well (capacity factor of 35%); however, nuclear power is selected instead. Figure 4 shows the total investments in capacity of the system. Basically, significant investments occur at year 7 and year 10 when existing coal and nuclear capacity is retired respectively.

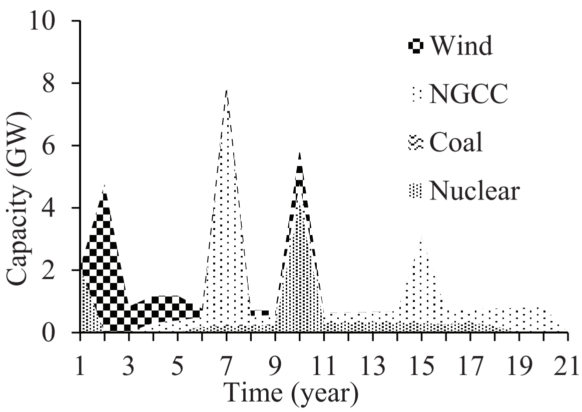

Figure 4 Aggregated system investments

NGCC capacity, as in the base-case simulation, is installed at each region to meet capacity reserve requirements. The factor that make NGCC units attractive for using them as peaking plants is their high total variable cost caused mainly by the quite high natural gas price (around $7/MBTU). So, it is cheaper to operate the system using nuclear and wind power as much as possible. The resulting optimal NGCC capacity factor is at most 10% as shown in figure 5.

An interesting feature of the planned systems is the continuous energy flow from east to west region. The proposed model captures the necessity of investing in clean energy like wind even if it is located far from the big load centers. Also, the model proposes nuclear energy as a good alternative to invest in to supply energy that cannot be covered only with wind power. Regarding carbon emissions, figure 6 shows the total CO_2 emissions limit and the actual level. In this case, with a 5% of annual emissions reduction rate in equation (12), it is enough to force the system to significantly reduce emissions, and the emission constraints are binding. But, if the emission tax is also imposed, emissions can even be lower as represented in figure 6. An important result regarding to our model that controls emissions is that a 22.7% of extra-investment cost, achieves a 93% of sustainability in terms of carbon emissions (emissions in this case are reduced 93% with respect to base case emissions).

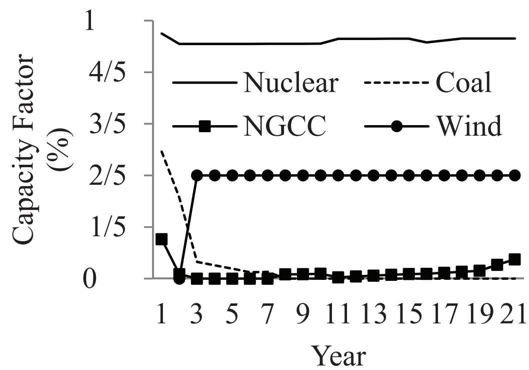

Figure 5 Capacity Factors

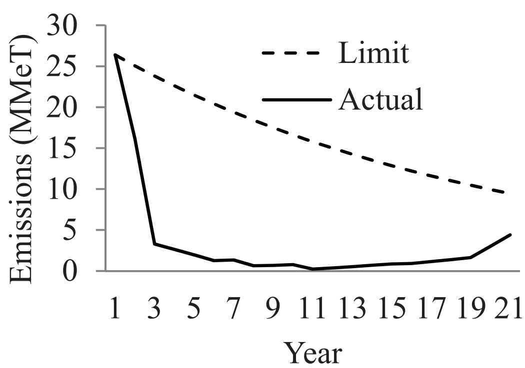

Figure 6 Annual carbon emissions

Bigger power system

The proposed model is computationally tractable and its applicability is bounded by the computational resources and by the optimization solver capability. However, to illustrate more realistic results, we implement this methodology over an 11-region power system, whose potential energy portfolio can be composed of up to 10 technologies. Besides nuclear (NUC), coal (CO), wind and NGCC the energy portfolio includes: integrated gasification combined cycle (IGCC), integrated gasification combined cycle with carbon sequestration (IGCCS), combustion turbine (CT), solar (SUN), and hydro (HYDR). Data regarding the transmission system is presented in table 2; other data of the system can be consulted in [16]. For 20 years of planning horizon, cvx (SeDuMi solver) reported 79.154 variables and 47.475 constraints. Figure 7 shows the aggregated investments results. Since all the coal capacity is assumed to be retired at year 10, significant investments need to be done. What is interesting is the fact that only investments in nuclear, NGCC and combustion turbines are added to the optimal portfolio. Reduced capacity credit of wind power reduces its dispatchability, which is assumed by combustion turbines. These provide more firm capacity to the system compared to renewable technologies. Figure 8 shows the system capacity evolution over the planning horizon. Notice that existing capacity of oil units and wind vanishes over time and is replaced by natural gas-based technologies (NGCC and combustion turbines). The total investment cost of this strategy is $2.374.6 billion. In terms of carbon emissions, the system produces 33.219 MMeT.

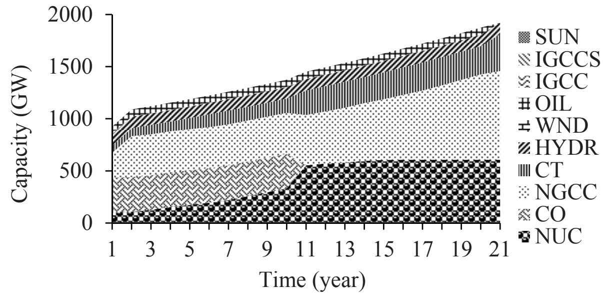

Figure 7 Aggregated investments results for an 11-region power system

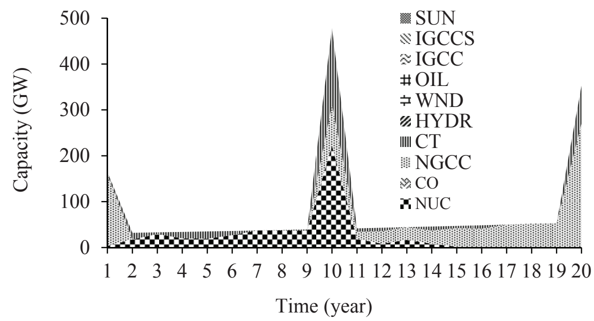

Figure 8 Capacity evolution for an 11-region power system

Table 2 Transmission system data of an 11-region power system

From Region	*To Region*	*Distance (miles)*	*Capacity (MW)*	*From Region*	*To Region*	*Distance (miles)*	*Capacity (MW)*
1	2	1057	6000	3	11	589	6000
1	6	830	6000	4	5	717	6000
1	7	459	6000	5	6	373	6000
1	10	695	6000	5	7	885	6000
2	4	1090	6000	6	7	797	6000
2	5	764	6000	7	10	624	6000
2	6	443	6000	7	11	660	6000
2	7	1146	6000	8	9	755	6000

From Region	*To Region*	*Distance (miles)*	*Capacity (MW)*	*From Region*	*To Region*	*Distance (miles)*	*Capacity (MW)*
3	4	1415	6000	8	10	1024	6000
3	5	828	6000	8	11	669	6000
3	6	972	6000	9	10	585	6000
3	7	546	6000	9	11	790	6000
3	8	1180	6000	10	11	585	6000

Conclusions

We presented an optimization to solve a power capacity expansion planning problem that minimizes investment and operational cost. The model considers the operational problem by including a discrete LDC into an approximated version of an OPF, and environmental policies. Policies consist on the taxation of CO_2 emissions plus and an annual carbon emissions limit. This approach guarantees a strongly cleaner electricity production in the expanded power system at a relatively low investment cost (price of sustainability). The proposed model is applied to a 4-region test system over a 20-year planning horizon and results show reasonable doable investment actions in terms of sustainability and costs. Future research work would consider energy market modeling to include a demand-side type of behavior that might reduce final energy price, data and model uncertainty to guarantee a robust planning solution, operational issues to obtain a more-accurate operational cost, and economic models that show how the expansion plan could be partially funded.

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