Air-Pollution Impact of Transmission Line Capacity Expansions in Power Systems

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Abstract

In this paper, we study the environmental effects on global and local pollutant emissions derived from the incorporation of new transmission circuits in existing corridors, and the interrelationships with the system economic costs and the system reliability variations. For that purpose, we develop a methodology that allows quantifying the indirect impact on pollutant emissions due to variations in power plants' dispatch when adding a line circuit to a hydrothermal power system. Our methodology also allows the analysis of the effect of N – 1 security criterion over the pollutant emission displacement, as well as the effect of changes in demand, the hydrology scenarios, and the failure cost. We illustrate our methodology using a simplified version of the main Chilean network.

1. Introduction

The network planning process is usually carried out to determine the optimal expansion of the transmission network based on economical and reliability criteria. On the other hand, environmental awareness has increased in the last decade, placing more relevance to environmental issues such as emissions from global pollutants (e.g., carbon dioxide, CO_2) and local pollutants (e.g., particulate matter, PM). All these pollutant emissions represent externalities that should be considered in the different stages of the network planning process as they affect, directly or indirectly, people's quality of life.

There are few studies that link local pollutant emissions in power systems with the transmission capacity. And those that exist do not consider a bottom-up approach, which is useful when the geographical dimension of some pollutants is taken into account.

Next, we review the literature about air pollution issues in dispatch and planning models for power systems.

Power dispatch models determine the operation point of power plants, such that a specific objective function is optimized. The least cost solution is frequently sought, although other objectives can be used (e.g., looking for the cleanest solution). Classifications of these models by objective, horizon, problem formulation, solution method employed and type of system to optimize are found in the literature [1-3].

Traditionally, variable cost minimization is used as the objective function when solving the optimal power flow (dispatch) problem, and emissions are not accounted as a part of these costs. For hydrothermal systems, like the one in Chile, Pereira and Pinto [4] proposed a Stochastic Dynamic Dual Programming (SDDP) approach to solve the dispatch problem accounting for the hydro uncertainty.

Environmental issues have been increasingly incorporated into the power dispatch problem during the last two decades, including emissions as an additional constraint and/or including them as additional terms in the objective function. Talaq et al. [5] summarize the power dispatch algorithms that consider both economic and environmental issues. In [6], the authors study the CO_2-emissions effect of the European network expansion plan using a dispatch model that co-optimizes costs and emissions. Moreover, the authors study what would happen if they use a purely ecological objective function while solving the optimal power flow (EOPF). Other authors [7-8] focus on determining the emission factors of different power generation technologies.

Regarding expansion planning models, there is a wide variety of algorithms to solve the generation expansion planning (GEP) and the transmission expansion planning (TEP) problems. Zhu and Chow [9] review several algorithms used for solving the GEP problem, while studies reviewing the TEP problem are numerous [10-12]. Some other authors propose the co-optimization of GEP and TEP problems [13-19]. As the co-optimization literature points out, one of the important benefits of co-optimizing transmission and generation investment is that induces more efficient generation investment. We acknowledge that this investment affect emissions. However, in our model, we ignore this effect because we do not consider generation expansion in our model.

Environmental aspects have also been addressed in the expansion planning processes. In [20], for instance, a GEP formulation is proposed for the Lebanon, accounting for

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environmental considerations constraining the emissions of CO_2, NO_2, SO_2 and particulate matter (PM). Environmental aspects are included in TEP models in [21-23]. In [21] and [22], the environmental variable (CO_2 emissions) is included in the objective function. The TEP problem is solved using genetic and simulated annealing algorithms in [21], while, in [22], the TEP is solved using mixed integer programming and accounting for security constraints and uncertainty in CO_2 prices. On the other hand, in [23], the authors develop a method for internalizing environmental costs in the social cost-benefit analysis of transmission expansions.

Some authors have created new measures to quantify the emissions effect of changes in one or more components of power systems. In [24] and [25], the authors propose the Marginal Carbon Intensity (MCI) and the Shadow Carbon Intensity (SCI) of a constraint to measure the infinitesimal variation of carbon emissions caused by changes in demand and by changes in some constraints of the system (e.g., the transmission capacity of a specific line), respectively. Although this approach is interesting to study the interactions between the power system components, it is less useful to plan real networks because the approach is only valid for expansions done in small discrete increments. Nonetheless, the analysis in [24] and [25] shows the relevance of network congestion in allowing a cleaner power dispatch. In [26], the author also shows that the congestion of power networks may impact power-system emissions in some unpredicted ways. In agreement with that, in [27], the authors developed some metrics of the efficiency of the transmission expansion, including a network congestion index (NCI), which we also use in this paper. Differently than our work, the work in [27] does not consider any environmental analysis at all.

A different approach is the one proposed in [28], where a life-cycle analysis of Great Britain's transmission network is done, focusing on CO_2 emissions derived from construction and operation phases. In [29], a review of the methodologies used to quantify greenhouse gas (GHG) emissions derived from transmission and distribution projects is carried out, and a classification of the effects associated with them is proposed. In [29], the authors highlight the "emission displacement" caused by structural modifications in the network, situation also mentioned in [30]. Topological changes in transmission networks, implies a change in the optimal dispatch of the power plants. Moreover, due the incorporation of new lines, new generation projects can contribute to further reduce or increase pollutant emissions [30].

Environmental issues also interact with the reliability of power systems. Generally speaking, there are two approaches commonly used for including security in TEP models. The first one is the deterministic "N-k" criteria, modeled by introducing redundancy in transmission lines and transformers for protecting against contingencies. The second one is a stochastic approach that uses network reliability indexes. This last approach generally results in a more computation time-expensive process [31-32]. In [23], the authors perform a cost-benefit analysis of the TEP process taking into account both environmental and reliability criteria. Specifically, their analysis includes the benefits of avoided emissions, avoided congestion and avoided non-supplied energy.

Within this context, the methodology proposed in this paper contributes to the identification and quantification of some environmental effects of building new transmission infrastructure. Quantifying the indirect impact on pollutant emissions due to variations in power plants' dispatch when adding a line circuit to a hydrothermal power system is an important first step for incorporating pollutant emission costs into transmission planning.

In particular, in this research work, we study the interrelationship between the power transmission system and the pollutant emissions. We also analyze the effect of N – 1 security criterion over the pollutant emission displacement, as well as the effect of changes in demand, the hydrology scenarios, and the failure cost. The main idea is to show that pollutant emissions in a power system have a close relationship with the network structure and the reliability level desired thereof. In doing that, we develop a methodology that allows to study and quantify the indirect impact on emissions due to the displacements of generation sources caused by adding transmission capacity. Furthermore, the relationships among reliability, pollutant emissions and system operational cost are also studied, and illustrated in the case of the main Chilean network, the Chilean Central Interconnected System (SIC, for its Spanish acronym).

2. Proposed methodology for assessing the displacement of pollutant emissions

In this paper, we study the pollutant emission displacement produced when adding some new transmission circuits in both new and existing corridors. We also analyze the effect of an N – 1 security criterion over the pollutant emission displacement, as well as the effect of changes in demand, hydrology scenarios, and the failure cost.

We consider global and local pollutants. As global pollutants, we consider GHG, including CO_2, NO_2, CH_4, and SF_6 among others. They are usually expressed in CO_2-equivalent (CO_2-eq) tons through its global warming potential.

Power systems also emit pollutants that damage a determined location, named local pollutants or health damaging pollutants. These local pollutants commonly include SO_x, NO_x, and PM, which affect premature mortality, hospital admissions, absenteeism and people labor productivity. In this paper, we consider $PM_{2.5}$,[1] NO_x, and SO_2 as the local pollutant to be analyzed.

Table 1 shows the correlation among the emission factors used in the case study presented in the next section (using a sample of size 164,088, equivalent to one-year monthly data of the 129 thermal power plants at each one of the 2 demand blocks and each one of the 53 hidrologies). As seen from Table 1, local pollutant emission factors are not well correlated with emission factors of CO_2. Consequently, including both global and local pollutant emissions in the analysis is crucial.

[1] $PM_{2.5}$ corresponds to the particulate matter composed of particles with a diameter less than 2.5 microns.

TABLE 1
THERMAL POWER PLANTS' EMISSION FACTOR CORRELATION. EMISSIONS IN (TON/GWH)

Correlation (n = 125)	$CO_{2,EQUIV.}$	$PM_{2.5}$	NO_x	SO_2
$CO_{2,equiv.}$	1	0.471	0.025	0.197
$PM_{2.5}$	0.471	1	0.377	0.593
NO_x	0.025	0.377	1	0.576
SO_2	0.197	0.593	0.576	1

We solve the hydrothermal power dispatch using an adaptation of the SDDP algorithm proposed by Pereira and Pinto [4]. This adapted model, called OSE2000, is the software used by the Chilean National Energy Commission in the power expansion planning and pricing processes. A detailed description and formulation of OSE2000 is found in [33].

As in [4], the dispatch model used here is characterized for being multi-nodal and multi-reservoir. The SDDP algorithm allows handling the "curse of dimensionality" problem that lies beneath stochastic dynamic programming, which does not allow solving large problem without significantly increasing computer requirements.[2] For this purpose, the SDDP algorithm uses Benders Decomposition, which is a tool that allows decoupling large mixed-integer problems, as power dispatch and planning problems, into easier (continuous) sub-problems, and solves them through the use of dual variables. In our case, the use of dual variables allows us to rebuild the future cost function as a piecewise linear cost function associated with water levels in reservoirs, in an iteration process for each time step.

From the supply viewpoint, the dispatch model assumes that generation firms reveal their true variable costs (i.e., there is no market power). From the demand viewpoint, it assumes inelastic demand, which is distributed over the network buses and months considered according to historical experience.

The decision variables of the dispatch model, which represent inputs on the emission-evaluation model, are the generation levels of all thermal plants and hydro-power plants, the power flows through transmission lines, and the non-supplied energy, for each monthly time step of the simulation.

Using this dispatch model, we obtain the optimal economic dispatch of the power plants under different network scenarios, which is used to calculate the emissions of both global and local pollutants, for each power plant, in every month of the time horizon. We assume there is no emission regulation (such as a cap-and-trade policy) in place.

We consider a time horizon of 34 years (from April-2012 to March-2046) in the economic evaluation. This horizon is divided in two types of periods. The first one is the simulation period that goes until March-2027 (including 2 filling years)[3] and is characterized by solving the dispatch model in a monthly basis. In the first 4 years of this simulation period, only the already proposed (planned) networks expansions are built. In a second group of periods (involving from April-2027 to March-2046) the last non-filling year, is repeated until the end of the evaluation horizon. This repetition period is only used for economic evaluation purposes (we assume transmission lines have a 30-year life) and does not account for demand growth, system expansions, or changes in fuel costs or emissions. Figure 1 illustrates the composition of the time horizon utilized.

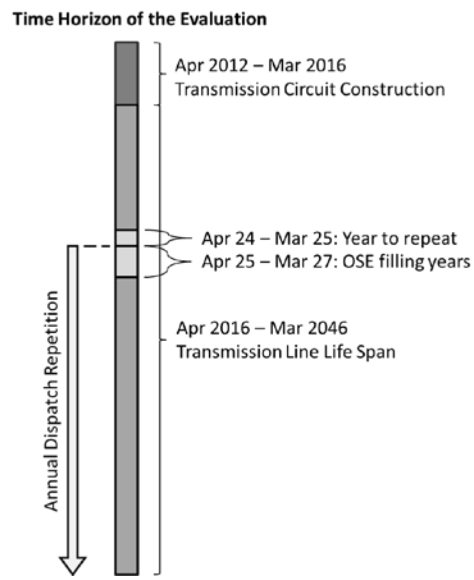

Figure 1. Evaluation horizon of the study.

We design three different experiments to study the pollutant emission displacement. First, a base scenario for the main Chilean network (SIC) is compared with 8 modified scenarios where new transmission circuits are added into a single (either new or existing) corridor. In addition, the base scenario is also compared with another scenario that adds together all the previous 8 new circuits. In this first experiment, the power system dispatch is always solved without incorporating the "N–1" criterion in any part of the network. This is made in order to isolate the "adding-a-circuit" effect.

In a second experiment, the base scenario is compared with a scenario with the same existing lines, but with the N–1 criterion included (this is done in order to isolate the N–1 criterion effect)[4]. In this second experiment, we also compare this last scenario (with N–1 criterion) with a new scenario both including the N–1 criterion and adding together all the previous 8 line expansions.

[2] The increment in the size of the state space (derived from higher discretization levels of decision variables) sets the need of finding other ways to solve problems where a high number of variables is involved. SDDP methodology avoids going through all the state space, lowering computational efforts, which represents the main advantage of the algorithm.

[3] Filling years are aggregated at the end of the simulation period to realistically optimize the use of the water reservoirs, avoiding that they get depleted at the end of the simulation period.

[4] Chilean transmission network takes into consideration an "adjusted" N-1 criterion in some predefined high-voltage lines, which is similar to the traditional N-1 criterion, with the difference that it considers operational limits of some of these lines determined by dynamic simulations of the system (to avoid stability issues, among others).

When expanding a certain corridor that is affected by this adjusted criterion (which is the case of lines expanded in simulation cases 1 and 8 of our case study), we have considered that the initial proportion between N criterion and N-1 criterion capacities is kept after the expansion.

In our experiments we use this adjusted criterion because it reflects the real operation of the SIC network.

The idea of elaborating these two separate experiments is to characterize the emissions impact of the incorporation of the N–1 criterion separately from the emission impact of capacity expansions.

Finally, in a third experiment, we carry out sensitivities over the power demand, the hydrology scenarios, and the failure cost, always including both the 8 previous transmission expansions and the N–1 security criterion.

In all experiments, electricity generation from each power plant is obtained for every month as a dispatch model output. Then, an energy difference (delta) is calculated between the base scenario and the modified scenario. Accordingly, by multiplying each energy delta and the corresponding emission factor, avoided total emissions are computed; see (1). Finally, by multiplying these avoided emissions and the value of the future prices of CO_2 allowances or the avoided marginal damage for local pollutants, a net present value (NPV) for each pollutant is computed; see (2) and (3). A 10% annual discount rate is used for computing the NPV, which the interest rate used in Chile for evaluating power projects. These calculations are summarized in (1)-(4).

$$\Delta TE_{c,k,t} = \sum_{b} EF_{c,k} \cdot \Delta GE_{c,t,b} \tag{1}$$

$$NPV_k = \sum_{t}\sum_{c} \frac{\left(AMD_{k,t,p(c)} \cdot \Delta TE_{c,k,t}\right)}{(1+r)^t} \tag{2}$$

$$NPV_{CO2} = \sum_{t}\sum_{c} \frac{\left(FP_t \cdot \Delta TE_{c,CO2,t}\right)}{(1+r)^t} \tag{3}$$

$$NPV_{Total} = \sum_{k} NPV_k \tag{4}$$

where (1) holds for each c, k, t; (2) holds for each k $\in$ {$PM_{2.5}$, NO_x, SO_2}; (3) holds for CO_2; t ϵ [April-2012, March-2046]; b ϵ {Off-peak demand block, peak demand block}; c ϵ {power plants of the SIC}; p(c) ϵ {Chilean provinces}; and c ϵ Province p(c). Notation is as follows:

- $EF_{c,k}$: Emission factor of pollutant *k* in power plant *c* [Ton/GWh].
- $\Delta GE_{c,t,b}$: Delta of the expected generated energy by power plant *c*, in month *t*, in the demand block *b* [GWh].
- $\Delta TE_{c,k,t}$: Aggregated delta of pollutant-*k* emissions in power plant *c*, in month *t* [ton].
- $AMD_{k,t,p(c)}$: Avoided marginal damage for pollutant *k*, in month *t*, for province (region) *p*, where it is located power plant *c* [$/ton].
- FP_t: Future price of CO_2 allowances, in month *t* [$/ton].
- r : Annual discount rate.
- NPV_k : Net present value of the avoided emissions of pollutant *k* [$].
- NPV_{Total} : Total net present value for the avoided emissions in the power system [$].
- $f_{L,i,t}^{max_{b,h}}$: Maximum flow among all hydrology scenarios and demand blocks for circuit *i* of transmission line *L* in month *t*.
- $cap_{L,i,t}$: Capacity of circuit *i* of the transmission line *L*, in month *t*.
- $w_{L,i,t}$: Binary variable that equals 1 if circuit *i* in the transmission line *L*, in month *t*, is operative.

The pollutant emission factors used in our calculations were taken from [34]. Regarding prices, we use the settlement price of futures of European Union CO_2 allowances for the global pollutants [35]. We use this information because it reflects the market expectations on permits value. Intermediate monthly values were calculated through a quadratic interpolation of the prices between April of 2012 and March of 2025.

Local pollutants prices were valuated using the avoided marginal damage for each pollutant, for each Chilean province, taken from [36]. The estimation method used in [36] consists in converting emission changes to pollutant concentration changes using atmospheric models, which generated changes in the exposure of the population in a determined zone. These changes in exposure to pollutants lead to changes in people's health by altering effects such as premature mortality, hospital admissions, absenteeism and labor restriction days, which are quantified using exposure-response functions. Then, the avoided cases of a determined effect are evaluated in [36] through three perspectives: cost of treatment, productivity loss and welfare loss. The first two represent the illness cost and the last one is equal to the willingness to pay.

In the analysis of our experiments, we also use other relevant indicators like the Expected Energy Not Served (EENS), the total operation cost (which includes total failure cost), and the flows through transmission lines. The latter are used to calculate a network congestion index (NCI), as shown in (5). NCI is a dimensionless magnitude which reflects the maximum use of the network for a defined time interval [27].[5]

$$NCI = \frac{\sum_{t}\sum_{L,i} \left| f_{L,i,t}^{max_{b,h}} \right|}{\sum_{t}\sum_{L,i} cap_{L,i,t} \cdot w_{L,i,t}} \tag{5}$$

3. Case study: the main Chilean power system

We illustrate our methodology using a simplified version of the Chilean Central Interconnected System (SIC), which has near 75% of the installed generation capacity of Chile. The SIC is characterized for being a hydrothermal system, where at least 40% of its energy comes from hydro resources.

[5] The reader should note that, although transmission expansions may start operating in an intermediate period of the horizon (e.g., April of 2016 in our case study), the changes in flows through lines may be reflected from the beginning of the time horizon, because of changes in the future cost function (i.e., the use of water reservoirs).

3.1. Parameters and evaluated scenarios

The SIC system was modeled using data from [37]. Table 2 shows the dimensions of the main components modeled in the SIC, across 53 hydrology scenarios (50 historical, 2 extra-dry and 1 extra-wet hydrology) and 2 demand blocks (a peak-demand block containing 2,316 hours and an off-peak block of 6,444 hours per year).

The time horizon (34 years) was defined in order to take into account the entire life span of the transmission line (considering a life of 30 years) and to better capture air pollution mitigation benefits.

TABLE 2
ELEMENTS MODELED IN THE SIC

N° of system nodes	203
N° of generation nodes	72
N° of demand nodes	114
N° of residential demand nodes	23
N° of industrial demand nodes	21
N° of both residential and industrial demand nodes	70
N° transmission system sections (circuits)	262
N° of power plants	218
N° of thermal power plants	129
N° of wind power plants	15
N° of run-of-the-river power plants	53
N° of reservoirs	10
N° of hydro power plants in series	11

After running the base-case simulation, we selected 8 circuits for transmission expansions. The choosing criterion was selecting the transmission corridors that were saturated in the largest number of hours (considering all hours in the non-filling years, in all months, in all hydrology scenarios, and in all demand blocks). We also impose the restriction that four out of the 8 cases consider the expansion of high-voltage lines of the Trunk System (back bone of the SIC). These are cases 1, 3, 5, and 8. Tables 3 and 4 show transmission data in the corridors selected for transmission expansion, before and after the circuit expansion, respectively.

TABLE 3
LINE DATA IN SELECTED CORRIDORS/LINES BEFORE THE CIRCUIT EXPANSION

CASE	Line	N° of circuits	Capacity [MW]	N-1 Capacity [MW]	Voltage [kV]	R [Ω]	X [Ω]
1	CN– LA	2	620	460	220	0.678	2.662
2	AJ– SR	2	142	71	110	0.962	3.08
3	LV-PO	0	-	-	-	-	-
4	CN– PU	2	188	94	110	0.012	0.048
5	QU-AJ	0	-	-	-	-	-
6	MA–FL	2	136	68	110	0.399	1.198
7	TE–PL	2	56	28	66	1.745	1.895
8	LA–PO	2	620	620	220	0.847	3.364

TABLE 4
LINE DATA IN SELECTED CORRIDORS/LINES AFTER THE CIRCUIT EXPANSION

CASE	Line	N° of circuits	Capacity [MW]	N-1 Capacity [MW]	Voltage [kV]	R [Ω]	X [Ω]
1	CN– LA	3	930	690	220	0.452	1.775
2	AJ– SR	3	213	142	110	0.641	2.053
3	LV-PO	2	450	225	220	4.783	22.664
4	CN– PU	3	282	188	110	0.008	0.032
5	QU-AJ	2	1100	550	220	3.099	16.821
6	MA–FL	3	204	136	110	0.266	0.799
7	TE–PL	3	84	56	66	1.163	1.263
8	LA–PO	3	930	930	220	0.565	2.242

As we explained before, we also analyze the effect of N – 1 security criterion over the pollutant emission displacement, as well as the effect of changes in demand, the hydrology scenarios, and the failure cost. Tables 5 and 6 summarize the cases that we evaluate for these purposes of the methodology. We remark that the base case of the first experiment of the methodology is the same that Case A in Table 5.

TABLE 5
CASES STUDIED IN THE SECOND EXPERIMENT OF THE METHODOLOGY

Case	N-1 CRITERION IN EXISTING SYSTEM (NO EXPANSIONS)	INCLUDED 8 PROPOSED EXPANSIONS	N-1 CRITERION IN PROPOSED EXPANSIONS
A	✗	✗	✗
B	✓	✗	✗
C	✓	✓	✓

TABLE 6
CASES STUDIED IN THE THIRD EXPERIMENT OF THE METHODOLOGY (SENSITIVITY ANALYSES)

Case	Sensitivity
C	Introduction of N-1 Criterion
D	10% Decrease in Demand
E	10% Increase in Demand
F	Prevailing Wet Condition
G	Prevailing Dry Condition
H	Increase of 50% in the failure cost
I	Increase of 100% in the failure cost

3.2. Results

The results of the first experiment are presented in Table 7. In this table, the nomenclature adopted for the computation of deltas (which represent the results of each case) is as follows. For non-monetary values, they are calculated as $X_{Result} = X_{Case\ i} - X_{Base\ Case}$, where X represents a non-monetary variable (e.g., EENS, NCI, etc.). For monetary values, they are calculated as the negative of the costs, for obtaining the benefits associated with the expansion. That is, $Y_{\$} = -\left(Y_{Case\ i,\$} - Y_{Base\ Case,\$}\right)$, where Y represents a cost variable (e.g., environmental cost or operational cost).

Recall that this experiment considers the expansion of each line circuit (cases 1 to 8) and the case including all 8 circuits, always ignoring the N-1 criterion.

As a reference for understanding the dimensions on Table 7, the dispatch model outcomes in the base scenario are presented next. Values are given for the entire horizon.

Base Energy Generation	=	2,555,623	[GWh]
Base NCI	=	46.2%	[%]
Base CO_2	=	973,838,494	[ton]
Base $PM_{2.5}$	=	101,538	[ton]
Base NO_x	=	1,008,540	[ton]
Base SO_2	=	660,142	[ton]
Base EENS	=	210,250	[GWh]
Base Operational Benefits	=	-69,974	[M$] [6]

In addition, Figure 2 presents the electricity generation evolution for the base scenario in the study horizon.

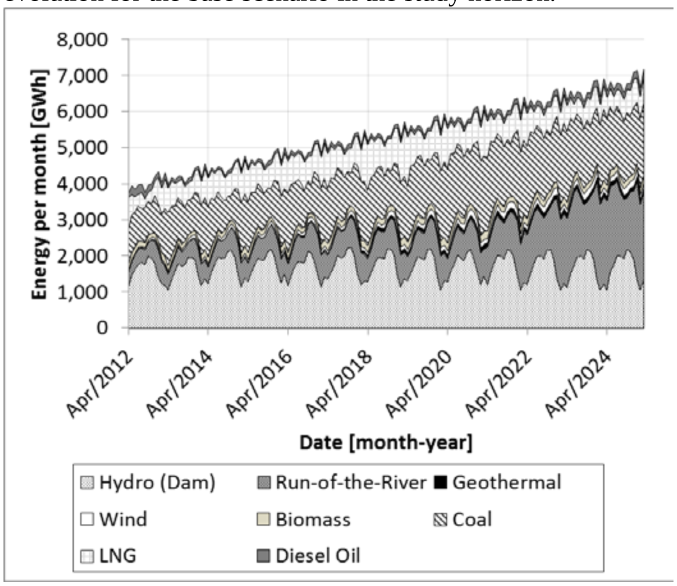

Figure 2. Energy matrix evolution for the base scenario.

The results of the second experiment[7] are presented in Table 8, using the same nomenclature as before for the computation of deltas. However, it is important to note that, for Case B of Table 8, the base case is the same as the base case in the first experiment. On the contrary, for Case C of Table 8, the base case corresponds to Case B. All results in Table 8 are expressed with respect to the corresponding base case.

The results of the third experiment are presented in Table 9, using the same nomenclature as before for the computation of deltas. This experiment considers the sensitivity analyses on the power demand, the hydrology scenarios, and the failure cost, always including both the 8 previous transmission expansions and the N–1 security criterion. For the sensitivities in the demand, hydrology and failure cost (Cases D to I), the corresponding base case is Case C. For Case C, its case base is Case B.

3.3. Result discussion

A first observation from Table 7 confirms that, in most cases, a line expansion leads to a reduction of the system cost. However, as pointed out in [13], some circuit additions may increase system cost. This is the case in Case 3 and Case 8. Those cases represent transmission line expansions in the trunk system, and the negative value is mainly explained due to changes in the water future cost function, which imply that there are more energy production in the operation even before the circuits come into operation in 2016.

Now, focusing on pollutant emissions, the total NPV is positive (beneficial) in two cases (Case 3 and All Lines altogether). This can be explained because the expansions were proposed based on congestion levels (as it is actually done in practice), and not with the aim of reducing emissions.

Accordingly, in most cases, the increase in transmission capacity allows exporting more energy and/or replacing some expensive-cleaner sources with other cheap-dirty ones during certain hours, “dirtying” the cost-effective generation mix. We can identify two different effects affecting emissions: “generation source replacement effect” and “temporal displacement effect”. The first one refers to situations where, during certain hours, generation sources are replaced by other cleaner/dirtier sources in the same location or sources located in other provinces where the avoided marginal damage (AMD) is lower/larger. The second one represents the environmental benefits derived from the use of clean technologies in the short term in exchange of greater environmental costs in the future, or viceversa.

Nevertheless, it is remarkable that, although total NPV of avoided emissions is negative (detrimental) in most of the cases (all cases other than Case 3), the total NPV of avoided emissions is positive (beneficial) when adding all 8 circuits together. This fact highlights the complexity and nonlinearity of power-systems’ behavior.

In terms of costs, the changes on operational benefits are significantly greater than the associated environmental impacts, representing a percentage lower than 5.5% in 5 cases. We can also observe that, when adding all circuits together, the impacts are greater than the direct sum of the impacts of adding each circuit separately. Nevertheless, from Table 7, we note that, by adding these 8 circuits to reduce network congestion, we get environmental benefits of $44 million.

[6] Negative sign in Base Operational Benefits implies it corresponds to base operational costs.

[7] Recall that this experiment compares the base scenario of the first experiment and a scenario with the same existing lines, but with the N–1 criterion included, and it also compares this last scenario and the scenario including both the N–1 criterion and all previous 8 line expansions.

TABLE 7

RESULTS OF THE FIRST EXPERIMENT OF THE METHODOLOGY, CONSIDERING THE ENTIRE TIME HORIZON.

CASE	CO_2 NPV [x 10^3 $]	$PM_{2.5}$ NPV [x 10^3 $]	NO_x NPV [x 10^3 $]	SO_2 NPV[x 10^3 $]	Total NPV [x 10^3 $]	Energy Delta [GWh]	NCI Delta [%]	CO_2 Delta [Ton]	$PM_{2.5}$ Delta[Ton]	NO_x Delta [Ton]	SO_2 Delta [Ton]	EENS Delta [GWh]	O.B.D [x 10^6 $]
1	-$ 8,501.7	-$ 171.3	-$ 529.1	-$ 25.8	-$ 9,227.9	-56.0	-0.26%	1,289,372.7	70.7	749.6	485.3	-52.6	$ 0.4
2	-$ 75,886.6	-$ 2,261.9	-$ 10,358.9	-$ 1,538.7	-$ 90,046.1	20,126.0	0.71%	11,012,972.4	944.9	11,182.0	5,951.4	-20,045.4	$ 4,329.7
3	$ 13,386.8	-$ 848.4	$ 439.3	$ 525.1	$ 13,502.8	1,518.8	-0.02%	-2,057,262.0	-200.1	-377.7	-1,775.3	-952.3	-$ 10.1
4	-$ 1,787.0	-$ 5,583.9	-$ 5,078.0	$ 3,141.3	-$ 9,307.7	8,608.7	-0.13%	214,394.9	-711.8	-4,917.4	-6,190.7	-8,853.5	$ 1,198.4
5	-$ 7,118.1	-$ 11,073.7	$ 486.9	$ 486.4	-$ 17,218.4	2,635.8	-0.29%	1,117,395.7	-33.3	-2,140.6	-765.6	-747.6	$ 139.2
6	-$ 13,316.8	-$ 3,754.8	-$ 3,512.1	-$ 1,302.7	-$ 21,886.4	2,346.5	0.05%	1,975,116.4	310.1	2,909.5	2,584.7	-2,279.0	$ 550.3
7	-$ 29,257.9	-$ 3,838.7	-$ 5,133.8	-$ 451.0	-$ 38,681.4	4,142.2	0.11%	4,191,544.7	577.3	5,890.2	733.3	-3,806.6	$ 761.6
8	-$ 12,045.4	-$ 1,601.5	-$ 1,247.1	-$ 698.3	-$ 15,592.4	-156.9	0.06%	1,801,971.2	162.7	1,567.0	1,109.5	-10.3	-$ 32.8
All	-$ 100,045.4	$ 80,274.9	$ 20,406.5	$ 43,983.6	$ 44,619.6	38,284.2	0.19%	14,445,794.7	415.4	5,215.0	-2,343.0	-36,633.7	$ 7,229.2

O.B.D corresponds to the Operational Benefit Delta. In this Table (as well as in Tables 8-9), it holds that: $\Delta\sum_i GeneratedEnergy_i = \Delta\sum_i EnergyLosses_i - \Delta\sum_i EENS_i$, where i represents the system node and Δ reflects the difference between the comparison case and a base case, with the same demand. This relationship shows that, when we have constant demand, the energy deltas can be explained through a change in the transmission network losses or as a change in the EENS. Thus, a positive change in energy generation implies increased energy losses or the decrease of the EENS (and a negative change, the opposite). Notice that this relationship does not show a direct dependence of transmission flows, allowing us to analyze the NCI independently of the other two variables.

TABLE 8

RESULTS OF THE SECOND EXPERIMENT OF THE METHODOLOGY, CONSIDERING THE ENTIRE TIME HORIZON.

CASE	CO_2 NPV [x 10^3 $]	$PM_{2.5}$ NPV [x 10^3 $]	NO_x NPV [x 10^3 $]	SO_2 NPV[x 10^3 $]	Total NPV [x 10^3 $]	Energy Delta [GWh]	NCI Delta [%]	CO_2 Delta [Ton]	$PM_{2.5}$ Delta[Ton]	NO_x Delta [Ton]	SO_2 Delta [Ton]	EENS Delta [GWh]	O.B.D [x 10^6 $]
B	$ 404,772.1	$ 44,353.9	$ 61,688.2	$ 13,820.2	$ 524,634.4	-101,157.4	6.75%	-57,238,028.3	-4,957.9	-52,769.3	-31,149.7	105,690.2	-$ 24,914.3
C	-$ 356,599.8	-$ 78,604.3	-$ 64,833.2	-$ 22,626.4	-$ 522,663.6	80,151.5	2.27%	51,519,790.7	5,302.8	52,794.6	36,186.8	-82,985.0	$ 16,881.1

TABLE 9

RESULTS OF THE THIRD EXPERIMENT OF THE METHODOLOGY (SENSITIVITY ANALYSES), CONSIDERING THE ENTIRE TIME HORIZON.

CASE	CO_2 NPV [x 10^3 $]	$PM_{2.5}$ NPV [x 10^3 $]	NO_x NPV [x 10^3 $]	SO_2 NPV[x 10^3 $]	Total NPV [x 10^3 $]	Energy Delta [GWh]	NCI Delta [%]	CO_2 Delta [Ton]	$PM_{2.5}$ Delta[Ton]	NO_x Delta [Ton]	SO_2 Delta [Ton]	EENS Delta [GWh]	O.B.D [x 10^6 $]
C	-$ 356,599.8	-$ 78,604.3	-$ 64,833.2	-$ 22,626.4	-$ 522,663.6	80,151.5	2.27%	51,519,790.7	5,302.8	52,794.6	36,186.8	-82,985.0	$ 16,881.1
D	$ 1,169,308.3	$ 153,437.2	$ 188,085.0	$ 77,128.6	$ 1,587,959.1	-200,234.0	-1.14%	-166,007,923.0	-17,150.5	-191,810.5	-121,290.4	-70,624.9	$ 21,178.5
E	-$ 1,012,292.7	-$ 102,379.7	-$ 155,093.6	-$ 45,115.5	-$ 1,314,881.4	188,798.6	1.36%	143,208,603.1	11,988.2	151,621.4	76,031.2	82,582.2	-$ 24,345.0
F	$ 206,576.3	$ 18,247.8	$ 29,451.4	$ 9,048.0	$ 263,323.5	2,868.6	-1.46%	-28,856,967.5	-2,553.0	-28,424.1	-15,736.5	-1,520.7	$ 1,329.7
G	-$ 165,060.8	-$ 19,613.7	-$ 23,500.9	-$ 10,008.3	-$ 218,183.8	-2,327.8	-0.70%	23,233,832.8	2,334.5	23,800.3	15,982.1	806.5	-$ 773.4
H	-$ 74,526.0	-$ 6,620.4	-$ 18,179.9	-$ 5,153.9	-$ 104,480.2	5,383.1	-0.12%	10,135,230.5	1,282.6	16,330.1	9,936.9	-1,639.2	-$ 24,593.3
I	-$ 144,549.9	-$ 11,077.0	-$ 30,799.6	-$ 8,316.8	-$ 194,743.1	9,072.6	-0.22%	19,843,225.4	2,167.5	28,617.7	15,040.9	-2,500.6	-$ 49,082.1

From Table 7, we can observe that environmental NPVs are not directly correlated with the operational system costs. This is explained by three factors: cheaper power plants do not mean cleaner ones, avoided marginal damage has a locational nature while economic costs have not necessarily a locational nature, and the hydrological-temporal coupling of the dispatch allows generation mix adequacy over time.

Regarding the relationship between environmental NPV and total emissions, both deltas usually move in the same (non-beneficial) direction, although there can be situations where they have opposite directions. The positive emissions delta/ negative NPV and negative emissions delta/positive NPV represent the most frequent cases, where more emissions imply a negative NPV, for a determined pollutant. Nevertheless, the positive/positive and negative/negative combinations are also possible (e.g., in $PM_{2.5}$ and NO_x deltas for the case with all the lines and NO_x deltas for Case 4, respectively). The positive/positive combination (more pollution, but a positive NPV) is explained because of the temporal displacement of generation, using cleaner sources in the short term and sources with more emissions in the long term, and the displacement of generation from provinces with higher AMD to lower ones. In the same way, the inverse situation explains a negative/negative combination for NPV and emissions deltas.

Looking at the decomposition of the total NPV among its individual components, we observe that transmission additions may have a relevant impact on local emissions and not just in the global ones. In fact, in some cases like Case 4, the NPV of a determined local pollutant (SO_2) can be higher than the NPV of CO_2, but with the opposite sign. In addition, it is interesting to note in Table 7 that the $PM_{2.5}$ NPV is negative in all of the proposed lines individually. It is also interesting the fact that the case where all lines are considered has a notably larger SO_2 NPV than the single-line cases, which can be attributed to the replacement of coal by liquefied natural gas (LNG) at the end of the simulation horizon.

Including the expected generated energy in the analysis is relevant to notice that transmission expansions may allow the supply of more energy, decreasing EENS. This can be clearly observed in the case when all proposed circuits are added into the system. In that case, the expansion plan allows a more economically-adapted network, as supply fits better demand, and the EENS significantly lowers. In this case, however, SO_2 emissions decrease because of the replacement of coal with LNG at the end of the simulation horizon. From the results we can also demystify that more power generation imply a dirtier energy mix, since the additional energy may come from hydro or other clean sources.

Several sensitivity analyses were developed to address the effects of adding new circuits on environmental and operational changes of the power system. Firstly, we analyze the effect of N-1 criterion introduction over certain lines (see Table 8). Table 8 shows how N-1 criterion introduction affects the system operation. In Case B, we can see that the N-1 criterion affects the generated energy decreasing it significantly over time because the energy evacuation from generation sources to consumption points becomes more difficult (i.e., congested). In this way, as we lower the transmission capacity of certain lines, some power flows must be redistributed over the system to supply demand, increasing the NCI.[8] We can also see that EENS increases significantly, as less energy is generated, leading to larger operational costs (lower operational benefits). On the other hand, N-1 criterion application involves an important reduction in the emissions accompanied with positive NPVs, derived from the reduction of generated energy. When adding all the proposed expansions/lines together, in Case C, the generated energy increases significantly while EENS decreases in a similar amount. NCI increment is consistent with this, and larger generated energy results in larger use of transmission lines. In terms of environmental variables, the power generation increment is mainly given by thermal sources, dirtying the energy mix, and causing emissions quantities to be increased and environmental NPVs to be decreased.

Then we study the effects of changes in demand, hydrology scenarios, and failure cost (see Table 9). In Table 9, the entire demand is increased and decreased by 10% in Case D and E, respectively. As it is evident from Case D and E in this table, an increment on demand entails higher operational costs and higher transmission network usage. By counterpart, a decrease on demand leads to the opposite conclusions. Moreover, we notice asymmetry of the deltas for both demand variations. This happens because the non-uniformity of the generation (different variable costs and emission factors) and the network topology. In this way, it can be seen that the decrease of operational benefits when increasing the demand is greater than the increment of the benefits when demand is decreased.

Case F corresponds to the case where we eliminate

[8] With N-1 criterion introduction, transmission operating limits are lowered, although line functional thermal limits are the same, so the line capacities used in the NCI calculation, in (5), do not change.

the six driest hydrology scenarios from the possible hydrologies. Inversely, in Case G, we eliminate the six wettest hydrology scenarios. When eliminating the driest hidrologies, hydraulic resources are relatively more abundant and, due to their null variable cost, their use implies a reduction of system cost and emissions. Inversely, when wettest hydrology scenarios are eliminated, thermal resources are more used, leading to larger costs and emissions. Thus, the obtained NPV can be explained with the "generation source replacement effect", where thermal sources are replaced by water resources or vice versa.

Finally, in Cases H and I, we increase the long-term failure cost (from its current value of $518/MWh) by 50% and 100%, respectively. As expected, an increase in the failure cost implies a reduction of the EENS. However, the EENS was not significantly reduced, reflecting that technical limitations are currently preventing a higher effect. To supply this additional energy, the system uses more expensive (and maybe dirtier) sources. In this case, there is the same amount of water resources, so additional load (derived from the lower EENS) must be mainly supplied by thermal resources, thus dirtying the energy matrix in comparison with the corresponding base case. As well, the NCI decreases because of a larger usage of a few lines, but lower usage of the rest of the system.

4. Conclusions

From an academic viewpoint, it results attractive to study how transmission planning changes when incorporating the pollutant emission costs into the transmission planning objective. Although this is an interesting question, which we left for future research, the reality in several power systems is that transmission planning is governed by cost minimization rules that do not still consider pollutant emission costs into the transmission planning objective. Within this context, the proposed methodology contributes to identify and quantify some environmental effects of building new transmission infrastructure.

Accordingly, we proposed a methodology to assess the air pollution impact of some power transmission projects, in a manner that facilitate the analyses of relationships among pollutant emissions, reliability, network usage, and operational costs. This methodology is based on the determination of locational and temporal signals (pollutant values and power plants dispatch), so the changes in pollutant emissions can be evaluated.

Differently than existing literature, our work simultaneously considers detailed optimization models for representing the power system, hydrology uncertainty, and local-pollutant emissions analysis, which highlights the novelty of our analysis.

From an environmental viewpoint, we observe three relevant related effects: the replacement of power sources with different emission factors and locations (generation source replacement effect), the displacement of generation and emissions from present to future (temporal displacement effect), and the variations on EENS levels (as higher EENS values may involve a cleaner operation of the system).

Some counterintuitive results obtained when applying the methodology to the main Chilean network (SIC) highlights the importance of making a detailed analysis by pollutant. In this case study, the environmental benefits are of the order of 0.1% of the costs of the transmission lines. However, the main idea is not justifying transmission investments by environmental benefits, but only considers the environmental co-benefits obtained when making transmission investments.

The proposed methodology may also contribute to the analysis of renewable-energy and energy-efficiency policies, as the meeting of their objectives must be supported by an appropriate transmission network. Indeed, power transmission represents a cornerstone when developing such policies [17]. In particular, the proposed methodology may help to identify and quantify some environmental effects of building the needed transmission infrastructure to support diverse energy policies.

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6. References

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