Transmission expansion in fast growing economies and the challenges of renewables integration

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Abstract—Transmission expansion in fast growing economies imposes severe challenges to electricity markets, given the need for planning and executing major midterm investments in an environment of uncertainty in load growth and generation expansion, coupled to the arrival of distributed renewable energy resources. This paper describes the approaches of two countries, Brazil and Chile, to tackle the challenges of transmission expansion, focusing on treatment of uncertainties, schemes for implementing expansion plans, and problems currently faced by different stakeholders. Renewable energy projects have experienced a significant development in the two countries, despite of difficulties faced by project developers with regard to financing, contracting, and, particularly, grid connection. We discuss solutions adopted or currently under consideration for the integration of renewables to the transmission system.

Index Terms—transmission expansion, renewable energy, renewable integration, electricity regulation

I. INTRODUCTION

DEALING with uncertainty has always been a need for the process of planning and executing transmission expansion. Some of the most significant uncertainty sources within this process are those related to equipment costs (and consequently costs of candidate transmission projects), load growth (aggregate growth rates, specific spatial growth patterns) and generation expansion.

The integration of non-conventional renewable energy (NCRE, encompassing all renewables except large hydro) brings about new challenges to transmission expansion. There are important additional technical challenges, related to the correct dimensioning of transmission capacity and provision of voltage/reactive power support resources in order to tackle the short and medium term variability in output of the plants. Yet, another class of challenges relates to the determination of institutional attributions and responsibilities in the planning, auctioning and construction process, and to the design of appropriate cost and risk allocation schemes. These challenges are generally associated with the following characteristics of NCRE:

(i) The remoteness of project locations may demand grid connection solutions and transmission reinforcements with considerable total costs, and due to the smaller size of projects (with respect to large, traditional generation plants) these costs can be more significant in comparison with total project investments and can even be prohibitive to some investors.

(ii) The comparative smaller size of projects and (at times) the comparatively shorter construction lead times can lead to high numbers of candidate generators seeking connection in shorter time periods, which may lead to overload of the transmission planning teams.

In fast growing economies such as Brazil and Chile, the two countries analyzed in this paper, the abovementioned uncertainty sources are exacerbated, as significant GDP growth rates and persistent increases in the per capita energy consumption bring about high electricity load growth rates and fasten the pace of generation system expansion.

Also, the participation of NCRE in the Brazilian and Chilean electricity matrices (as well as in the matrices of other South American countries) has been increasing, and there is reason to believe that this situation will be maintained in the near future. The most relevant options to maintain these increases are small hydroelectric plants, wind, solar and biomass power plants, especially cogeneration plants using sugar cane bagasse. The South American region is among the most promising lands for the development of NCRE, with its strong and persistent wind flows (load factors of 40-45% for wind power are common in some countries), availability of suitable sites, and thousands of sunny hours a year. In addition, the region’s hydro reservoirs can easily smooth out production fluctuations of intermittent (wind and solar) or seasonal (biomass) energy sources, thus providing operational flexibility and facilitating their reliable and economic integration [1].

Some support mechanisms for NCRE have been present in the South American region for the past 10 years [2-5], typically under the form of fiscal or tax incentives for renewable development in states or municipalities. At the beginning of the last decade, Brazil and Argentina implemented costly subsidies (similar to the feed-in tariffs in Europe) to foster renewables. Afterwards, with the implementation of long-term auctions for energy contracts to attract new generation beginning in 2004, auctions gained momentum and also started to be used in several countries as
the main (explicit) support scheme for NCRE beginning in 2007. This is the case of Brazil and Peru, where renewable auctions complement the regular auctions to attract conventional generation. Chile has opted for a compulsory quota scheme placed on the generators (they have to demonstrate that part of the energy contracted is being supplied by NCRE). Another source of funding for NCRE in the region has been the carbon market associated with the United Nations clean development mechanism (CDM).

All of these factors contribute to making Brazil and Chile relevant cases studies for regulatory and institutional solutions for treating uncertainty in the transmission expansion process. This paper aims at presenting and discussing the regulatory frameworks that Brazil and Chile have adopted to deal with uncertainty in transmission expansion, with emphasis on the approaches adopted for the integration of NCRE. We separately address the main issues on dealing with transmission expansion in Brazil (Section II) and Chile (Section III). In Section IV, we present the conclusions of this work.

II. TRANSMISSION EXPANSION IN BRAZIL

As other fast-growing South American economies, Brazil has experienced high levels of load growth over the last years. Energy consumption has grown about 4.4% per year in the last decade, and peak demand has shown similar growth rates. The summer-peaking country had a peak demand of 71.4 GW in December 2011 (with a secondary peak of 71.1 GW in February of the same year).

In order to keep up with those figures, the total length of the Basic Grid (transmission facilities with nominal voltage greater than or equal to 230 kV) had an average annual growth of about 4% over the last decade, as illustrated in Fig. 1. This figure also depicts the evolution of the Annual Allowed Revenue (AAR), which is the remuneration of the system to be recovered by transmission charges in each year, as explained in Section II.A. The higher growth rates of AAR, in comparison with system length, are partially explained by the former being adjusted yearly by inflation.

Recent projections by the State-owned Energy Planning Company (EPE) indicate average consumption growth rates of 4.6% and average peak demand growth rates of 4.7% until 2020 [6]. Conservative estimates of transmission system reinforcements associated with this growth in the period 2011-2020 are shown in Fig. 2.

![Transmission system reinforcements (2011-2020) [6]: additional length of overhead lines (OHL, left) and transformer capacity (right).](image)

Fig. 2. Transmission system reinforcements (2011-2020) [6]: additional length of overhead lines (OHL, left) and transformer capacity (right).

A. Overview of Transmission Expansion and Cost Recovery

The Brazilian HV transmission regulatory framework mixes indicative planning and competition in the process of designing and remunerating transmission reinforcements:

(i) Every year, EPE proposes a network expansion plan for the next five years. This plan is initially submitted to a public hearing, and is then assessed and approved by the Ministry of Mines and Energy (MME).

(ii) The regulator organizes auctions to procure the construction of the approved transmission reinforcements. Each bidder offers a fixed annual remuneration for the construction and operation of each transmission facility and the winner (smallest bid) receives the requested remuneration when the facility starts operation.

(iii) The total revenue required by the Basic Grid in a given year (the AAR) is the sum of the fixed remunerations of all transmission facilities in operation in that year. The AAR is collected from the generators and loads on a 50%-50% basis, through (fixed) monthly charges, given by the product of the Transmission Use of System Tariff (TUST) by the Amount of Use of Transmission System (AUST).

As mentioned in Sections II.D and II.E, the TUSTs are informed to candidate investors prior to generation auctions. This aims at providing locational signals that contribute to an optimal integrated transmission and generation expansion.

In the following, we discuss the approach to dealing with three basic sources of uncertainty in transmission expansion: equipment costs, load growth and generation expansion (both traditional plants and renewables).

B. Treating Uncertainty in Equipment Costs

As discussed above, EPE is responsible for transmission expansion planning, issuing indicative plans at regular time intervals. Those are elaborated under a least-cost planning approach with N-1 reliability criteria, and standard reference costs are adopted for all transmission facilities. The transmission reinforcements specified in those plans are assessed and approved by MME, and later on auctioned.

Prior to auctions, ANEEL (the Brazilian Electricity Regulatory Agency) coordinates studies to set the opening (maximum) bids for each transmission facility or group of facilities. This is done with help of reference costs from a data
base that is issued publicly and periodically by the regulatory agency. The reference costs used by EPE in the planning process are basically coherent to those issued by ANEEL.

The estimates of equipment costs embedded in the opening bids estimated by ANEEL are rather conservative, as indicated by the average discounts on the winner bids of the transmission auctions of 2011: 53.5%, 22.7% and 24.9%. Those significant discounts suggest both that participants are likely to achieve investment costs below those calculated with help of the publicly available data base, and that auctions have been competitive.

This process essentially means that auctions serve as a means of discovering equipment costs, under the assumption that the future transmission owner, whose yearly remuneration for the facilities will correspond to its bid in the auction, is best qualified to discover the market prices. Though this mechanism has worked well, it is important to notice that discounts embedded in the bids for different allotments (groups of transmission facilities that form a single auctioned item) are far from being uniform, as indicated in Fig. 3.

![Fig. 3. Transmission auctions of 2011: overview of results (bids for AAR) per auction (Auc.) and allotment (Allt.).](image)

A number of different factors influence the discount for each allotment – e.g. the ability of transmission owners who have other facilities adjacent to those of a given allotment to bid more competitively due to economies of scale in the operation and maintenance costs. That being said, the large differences in discounts of different allotments might also suggest that the reference costs used in the definition of the opening bids (and also in the planning stage) may not be capturing specific regional factors that influence the actual costs – what could lead to lost opportunities to minimize the overall transmission system cost. Further analysis is needed to determine if those regional differences are in fact relevant, of if variations in discounts of different allotments are fully explained by other factors such as economies of scale in O&M, aggressive bids of market entrants, etc.

C. Treating Uncertainty in Load Growth

In order to plan transmission expansion, it is paramount to have long-term projections of peak demand in the points at which the Basic Grid interfaces with the network of distribution companies (distcos).

In Brazil, distribution utilities are responsible for these projections. On a yearly basis, distribution companies sign contracts with the Independent System Operator (ISO), in which they must inform projections the maximum yearly instant power demand (the AUST) at each connection point between their network and the Basic Grid for the next four years. The projection of the AUSTs for the subsequent year is binding, and distcos are subject to heavy penalties in case the maximum power demand in each of the connection points differs from the AUST by more than 10%. Those penalties cannot be passed-through to the supply tariff of end-consumers. Also, there are restrictive rules for updating the previously informed AUSTs for the other three years of the horizon when the next contract is signed – e.g., there are limits for decreasing or increasing the AUST, in percent of the previously informed values.

This mechanism basically transfers the risk associated with projections of load growth to the distribution companies. We should keep in mind that, within the Brazilian regulatory framework, transmission expansion is centrally planned and transmission owners are remunerated independently of the actual use of the facilities via the AAR mechanism, there being no incentives for the investors to propose or to look for projects that have high loadings rates and that are not underused.

Finally, it is worth mentioning that the current ±10% tolerance band is generally felt to be too tight for a number of distribution companies, especially those with high penetration of renewables in their system.

D. Treating Uncertainty in Generation Expansion: Conventional Generation

The information on the location of future generation projects is also a requisite for transmission expansion planning. In this section, we describe the approach to dealing with uncertainty in the location of conventional plants, whereas renewables are addressed in Section II.E.

In Brazil, generation expansion is driven by an auction-based system where two types of new capacity auctions are held in a yearly basis [7]: the main and the complementary auctions, in which long-term contracts are offered for new capacity that will be commissioned respectively in five and in three years. Planning of the transmission system associated with the winning projects takes place after those auctions, when the information on location and technical features of new generation is known.

The period of five or three years between the auctions and the product delivery date is deemed as sufficient to accommodate the process of auctioning and construction of the associated transmission system. In recent years, however, delays in the environmental licensing and construction process of important projects have been a reason for concern of different agents. One example of such delays is related to the first of two ±600 kV HVDC circuits that will span through 2,400 km to connect the hydro projects Santo Antônio and Jirau (which will together account for 6.9 GW of installed power) to the main load center in the Southeast of Brazil. As
of this writing, the commissioning of the circuit, originally scheduled for February 2012 (36 months after the associated transmission concession was awarded), is thought to happen in November 2012 [8], partially due to delays in environmental licensing.

If delays in commissioning of auctioned transport facilities prevent generators from accessing the grid, the entrepreneurs are exempt from the obligation of delivering energy, as long as they have fulfilled all of their obligations regarding construction of the transport facilities that connects their project to the Basic Grid. In these cases, demand bears the most significant costs of delays in grid access, including fixed revenues of generation plants contracted by availability, and the costs of having the amount of stranded energy substituted by generation of higher cost facilities, pushing-up the prices in the spot market. It is worth mentioning that there are incentives and penalties to transmission owners when such delays occur, but those are generally thought to be either too mild (discounts in the rent the transmission owner receives for the availability of their facilities, once they are put into operation) or too strong to be of practical use (annulment of concession contract).

Before moving on to the next section, it is worth pointing out that the candidates in generation auctions receive economic signals regarding the projected impact of the auctioned projects on transmission system costs. The TUSTs, calculated using a long-run marginal cost (LRMC) methodology [9], serve as economic signals for the siting of generations and loads, and are used by candidate investors in their economic evaluations prior to participation in generation auctions. Because transmission charges may vary by as much as 10 US$/MWh depending on plant location, they may promote one type of plant over the other. This means the TUST might be a significant component of the costs to generator owners and, ideally, should be known before the generation auction takes place, for risk management purposes. Since 2008 estimates of TUSTs for every candidate generator in the energy auctions are pre-calculated, released for the 10 next annual tariff cycles and remain fixed (updated by a consumer price index). This mitigates any exposure of the investor to tariff volatility. The demand segment is responsible for the monetary differences between the charges resulting from those pre-calculated tariffs and the charges that will result from the actual tariffs. The actual tariffs are obtained by applying the LRMC pricing scheme after the actual network is known (which will happen after the generation auction takes place).

E. Treating Uncertainty in Generation Expansion: Integration of Renewables

In the introductory section of this paper, we pointed out that the cost of grid connection facilities and of transmission reinforcements may be significant for determining the feasibility of NCRE projects, and that the comparatively smaller size of projects and the shorter construction times can lead to increases in the workload of transmission planning teams. These factors must be taken into account while designing mechanisms for dealing with uncertainty in transmission planning and cost recovery schemes for renewables. In particular, uncertainties also become relevant for the design of facilities that connect the projects to the bulk transmission system, as discussed in the following.

Brazil first faced those challenges in 2008, when hundreds of candidate biomass and small hydro projects, spread over 200,000 km² in the country’s Midwest, were to participate in a NCRE auction. Because of the urgent need to integrate about 80 NCRE plants, a connection option based on a cooperative transmission planning and connection scheme was designed jointly by investors, the regulator and MME. The core of this scheme was the cooperative planning of integration networks to connect the NCREs. These networks became known as SFGs (acronym for shared facilities for generators, i.e., facilities used exclusively by generators, but shared by different projects), and were designed with help of a computational model that optimally plans and locates an integration network with layers of shared connections (by means of collector and subcollector substations) at different voltage levels. As illustrated in Fig. 4, this avoids the need of individual connections from each generator to the Basic Grid.

By individually connecting each generator to the transmission network, opportunities for economies of scale would be lost. The concept of SFGs captures such economies of scale and results in benefits to generators, while making it simple to allocate the facilities’ costs only to those responsible generators (as opposed to what would happen if the facilities were to be considered as part of the bulk transmission network). For this allocation, a simple MW-mile scheme was used, through which the yearly charges of each generator were calculated in proportion to the use of each facility.

An auction mechanism, similar to the HV grid approach, is applied to concede the rights to build, operate and maintain SFG facilities. A preliminary integration network was designed and a preliminary cost allocation was issued for the initial set of generators. Next, generators were asked to reconfirm their intention to join the network construction pool by depositing financial guarantees (typically 500 US$/KW). The final network was redesigned for the set of confirmed generators, and more accurate cost estimates for the integration system were provided. Those more accurate estimates were issued by ANEEL before the NCRE Auction, and will be kept constant (as at July/2008) until June/2015. In parallel, estimates of TUSTs (for the bulk transmission network) were also provided to generators – those would be binding for a period of 10 tariff cycles. With this binding information on transport costs, generators could better form
their bids in the NCRE Auction.

After knowing the results of the generation auction, the final network (including SFGs and any reinforcements to the HV transmission grid) was then designed and an auction was conducted for its construction. This procedure was successfully employed in 2008, resulting in ANEEL carrying out a public auction for the construction of about 2500 km of 138 kV and 230 kV transmission lines to integrate about 30 NCREs. Fig. 5 illustrates one set of auctioned transmission facilities.

Modifications to the process described above were implemented beginning in 2009, because it was generally understood there could be considerable differences between the integration network designed prior to the auction and the actual system that would need to be constructed, due to the large number of candidate wind projects in the 2009 NCRE auction. This is illustrated in Fig. 6. It was generally recognized that the demand sector could be exposed to a significant monetary burden because transmission charges to generators estimated ex ante could be substantially below the actual system costs. This led to the abandonment of the procedure used in 2008.

Before: 411 Candidate Projects (13,341MW)
27 Subcollector Stations
29 Collector Stations

After: 7 Winning Projects (1,806MW)
3 Collector Stations
3 Subcollector Stations

In this new process implemented beginning in 2009, a preliminary planning process for the HV transmission network and for SFG facilities still takes place, and its outputs are also provided to generators prior to the auction. The generators, however, are provided with nonbinding information on the possible network topology and the location of the collector substation. The information serves as input for cost estimates developed by generator owners.

FIG. 5. CHAPADÃO SUBSTATION, ASSOCIATED SFGS AND EXCLUSIVE USE TRANSPORT FACILITIES

FIG. 6. ILLUSTRATIVE COMPARISON OF NUMBER OF CANDIDATE AND WINNING PROJECTS, 2009 NCRE AUCTION
contracted and supervised by a committee representing all agents (generators, transmitters, distributors and large industrial consumers).

(iii) This plan is initially submitted to a public hearing and afterwards is assessed and approved by the CNE.

(iv) CNE is responsible for organizing auctions to procure the construction of the approved new bulk transmission lines, while reinforcements of existing facilities have to be conducted by the transmission operator of those facilities.

(v) Smaller transmission lines, required by specific generation projects (for instance to reach the main grid), are built and financed by the project developer, and often given to the transmission operator for their management.

Transmission facilities in the main grid are paid 80% by generation and 20% by load.

B. Treating Uncertainties in Generation Expansion: Conventional Generation

The described procedure has had, in its application, a quite limited scope (cost minimization) and has not followed a robust energy planning model, where energy security, diversification, local and global emissions reduction, competition and access to local renewable resources and several other components of the energy policy may be integrated.

One of the particular weaknesses of the first 2006 application of the expansion process was the lack of an adequate treatment of risks. No uncertainties in equipment costs or on load growth were considered, assuming that they did not represent as much uncertainties as generation expansion. But, worse than that, the first study was even weaker in that it only considered one generation expansion scenario, as defined by CNE. Consequently, defined expansion investments were minimal and soon proved to keep the transmission bottlenecks inherited from the previous regulation. Fortunately, the regulation left scope for improvements, and the second study (in 2010) made significant changes, by considering three generation expansion scenarios and two load growth ones, and a Min Max criterion to assess risk and vulnerability. The proposed investments of the two studies are summarized in Table I.

However, even with the improvement in the treatment of risks of the second study, criticism has still arisen that the expansion is myopic and does not take into account different generation projects being considered, thus not facilitating the increase of competition in a heavily concentrated market (three generators control over 80% of the installed capacity in the main system). Newcomers often face barriers of entry with a transmission system that is not accessible to their injections, implying expensive additional lines that make projects uneconomical. New regulatory concepts that would lead to the building of more robust transmission networks are being considered by the government, after recommendations made by a special Advisory Commission for Electrical Development (CADE) formed in 2011. The Commission suggested to increment consideration of uncertainty in system expansion, while at the same time increasing transmission reliability. The concept of public interest transmission longitudinal corridors was introduced, with anticipated investment, resulting in lines with slack capacity to accommodate future entrants [10], probably increasing transmission cost, but allowing more competition that would reduce generation cost. Fig. 7 illustrates a simple example of the impact over the final consumer tariff of building an hypothetical two-circuit, 500 kV corridor over 2,000 km along the country, with an average investment of 730,000 US$/km. At present high generation costs, the impact in the final tariff of a home consumer is an increase of approximately 2%, but with the high chance that generation costs would be reduced importantly with increased competition.

The concept of a public electric transport system, making reference to the country’s successful motorway concession scheme, was also proposed, with the government intervening in facilitating rights of ways and environmental permits, which presently are extensively delaying transmission investment. Regulatory changes, laws and bylaws will have to be implemented to achieve these objectives.

C. Treating Uncertainties in Generation Expansion: Integration of Renewables

The main transmission network, essentially a longitudinal one running north-south along the country with its shoe string

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**TABLE I**


<table>
<thead>
<tr>
<th>Study</th>
<th>Investment Value [MMUSD]</th>
<th>Operation, Maintenance and Administration Cost [MMUSD]</th>
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</thead>
<tbody>
<tr>
<td>First Study (2006)</td>
<td>139.7</td>
<td>2.4</td>
</tr>
<tr>
<td>Lines</td>
<td>139.7</td>
<td>2.4</td>
</tr>
<tr>
<td>Substations</td>
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<td>0.0</td>
</tr>
<tr>
<td>Second Study (2010)</td>
<td>802.0</td>
<td>12.5</td>
</tr>
<tr>
<td>Lines</td>
<td>712.3</td>
<td>11.1</td>
</tr>
<tr>
<td>Substations</td>
<td>89.7</td>
<td>1.4</td>
</tr>
</tbody>
</table>

Fig. 7. Additional cost of transmission corridor in final tariff.
shape, remains far away from several areas of potential for renewable energy. It has historically been optimized to connect large scale generation in the south with load centers north. But the 2008 renewables law, which aims at having 10% NCRE injections by 2024, will imply important challenges to transmission expansion and the consideration of additional uncertainties. There has been much interest in mini hydro and wind developments.

Many NCRE projects are located further away from the main transmission system, west or east, and their connection to the grid is often a barrier for their integration. Sites with large mini hydro and wind power potential are often far away from the main system. Although they are partially exempted from transmission charges associated with the main transmission system (projects under 9 MW do not pay transmission tolls), NCRE projects often require a long and costly line to reach the main transmission system, turning the project uneconomical or, even worse, unfeasible. Besides, building a line may take years, while for example a wind park only takes 15 months.

The CADE commission also defined transversal public interest transmission corridors, aiming at building east-west corridors with enough slack to accommodate future potential NCRE projects, the additional unused capacity paid temporally by consumers or subsidized by the State. As new injections join the system, they start taking over the corresponding tolls. The concept is illustrated in Fig. 8. Again, the proposal is that uncertainties in generation expansion, NCRE in this case, are faced with “overinvestment”, the final balance assumed to benefit the final consumer.

IV. CONCLUSIONS

Treating uncertainty from diverse sources is a relevant aspect of transmission system expansion. The high load growth rates of fast growing economies result in a fast pace of system expansion, and in relevant uncertainties regarding load and generation patterns that must accounted for while planning transmission expansion.

In this paper, we analyzed different mechanisms used for treating uncertainties in Brazil and Chile. Though the nature of specific mechanisms and the allocation of risk among the agents differ by country, it is clear that both countries have shown recent developments on the treatment of uncertainties in the regulatory and institutional framework for transmission expansion. In particular, mechanisms that aim at facilitating the integration of renewables to the grid are currently being used or under consideration in both countries – those generally involve pro-active planning of transport facilities and/or differentiated cost allocation schemes in order to reduce the impact of connection costs on the projects feasibility.

V. REFERENCES


VI. BIOGRAPHIES

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