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POWER TRANSMISSION REGULATION IN A LIBERALISED CONTEXT: PROPOSALS BASED ON THE ANALYSIS OF TWO DECADES OF NOVEL SOLUTIONS IN SOUTH AMERICAN MARKETS

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After decades of reduced need for investment, transmission regulation is increasingly gaining relevance and complexity in liberalised power sectors, mainly due to the need to integrate sometimes distant and large-scale renewable energy sources. We identify the key principles that should be considered at three levels: transmission expansion, remuneration and cost allocation.

The proposals we develop are built upon an in-depth critical review of the noteworthy experiences matured in South America, a region which, besides leading restructuring back in the eighties and nineties has, with different levels of success, always relied on innovative solutions to deal with this crucial regulatory challenge.

Keywords

Transmission regulation; transmission tariffs; cost allocation; expansion planning.

1 INTRODUCTION

In a liberalised power sector, the transmission network is the meeting point for the different agents interacting in the wholesale electricity market. This central role requires a sophisticated regulation to coordinate the transmission system with the generation market mechanism in place, in order to maximise the overall efficiency of the electricity supply service. In the long term, a sound methodology for the expansion planning of the network must be identified; this methodology needs to be somehow coordinated with the generation expansion, which, in a market environment, is the outcome of agents' decisions. In the medium term, open and non-discriminatory access to the grid must be guaranteed to all the market agents, but at the same time priority rules for network access when conflicts arise around limited capacity have to be outlined. Furthermore, network charges paid by different players must reflect the benefits generated by the network and should not distort the proper operation and planning decision-making process.

Transmission regulation is particularly relevant in South America. Geographically speaking, the region is characterised by large countries and low population densities, with the load being usually concentrated in specific zones or bands, commonly far from the main energy resources. Furthermore, the shape of the territory combined with the presence of the Andes mountain range creates additional challenges to network development and resulted in radial transmission grids (being Brazil the main exception). From the historical point of view, South America pioneered power sector restructuring and liberalisation, with the Chilean reform dating back to 1982 and Argentina, Peru, Colombia, and Brazil having restructured their sectors between 1992 and 1996 (Batlle et al., 2010). Differently from other systems in the world, these liberalisation processes occurred in a period of intense development of the power sectors, with demand growth rates near to or higher than 5%, which have been more or less maintained until the date. This required a sustained network expansion in a market environment, to be coupled with the liberalised generation siting[1]. Furthermore, the

[1] A further complexity is related with the economic evaluation of new generation projects, which has to take into account an estimate of the associated transmission charges (to be paid by generators too). Thus, transmission charges may "tip the scale" in favour of one technology over the other. On top of this, renewable

economic impact of the transmission segment on the overall power sector cost, which, for example, in Europe usually is in the range of 5% (10% at most), in some South American countries, as e.g. Chile or Brazil, can reach 20% (Rivier et al., 2013) or even more.

Because of these reasons, during the last decades, South American regulators[2] have implemented a variety of innovative solutions to regulate the power transmission activity which represent a source of relevant guidelines for the elaboration of a robust transmission regulation. Based on an in-depth analysis of these solutions, the authors put forward regulatory proposals on three levels: grid expansion, transmission regulation, and cost allocation. These guidelines could be particularly useful in the current context of development of very large renewable energy projects[3], whose proper deployment will necessarily require a redesign of transmission networks, and, consequently, of the regulation of this segment.

2 METHODS

This article presents an in-depth analysis of the transmission regulation implemented in the main five South American power sectors (Argentina, Brazil, Chile, Colombia, and Peru[4]). The

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facilities are frequently far away from the demand and their construction times are often shorter than the ones relative to the transmission grid, if administrative procedures are considered, as mentioned in Rious et al. (2011).

[2] In this paper, by regulators we refer to those institutions which actually design the regulation, not necessarily the Regulatory Authority.

[3] For an analysis of the economic benefits of transmission expansion in a scenario of increased penetration of renewable generation technologies in the European Union, see Becker et al. (2014). For an identification of the main challenges to be faced by the EU Internal Electricity Market in terms of grid expansion and network cost allocation, see Glachant and Ruester (2014).

[4] Other power sectors in the region, as e.g. Venezuela and Ecuador, are not suitable for this study because of the lack of a proper liberalisation of the sector.

methodology used for such analysis is a regulatory review whose structure (and the terminology used) follows the one outlined in Rivier et al. (2013), who present a textbook overview of transmission regulation. Thus, the study is focused on three main topics: network expansion, transmission remuneration, and cost allocation. Congestion management, due to its relation with the dispatch and the market design, lies out of the scope of this article and it is not included in the discussion.

3 RESULTS AND DISCUSSION

The results of this analysis are presented as a country-by-country review followed by a comparison of the regulatory mechanisms. Due to the methodology chosen, results the discussion has been combined in this section.

3.1 Argentina

Argentina is the 8th largest country in the world, and has one of the lowest population densities in the world. The demand is concentrated in specific zones of the country and only the Grand Buenos Aires area accounts for around 40% of the electricity consumption. On the other hand, both fossil fuels and hydropower resources are located in the inner and the southern provinces. These conditions give the transmission segment a central role.

3.1.1 Expansion planning

The main factor that drove the significant redesign of the transmission regulation in Argentina was the expansion of the main corridor necessary to move electricity from Comahue hydropower plants to the demand in Buenos Aires (1 300 km of line). The Electricity Act that reformed the Argentinean power sector in 1992 addressed this issue by introducing a novel regulation, presented here, whose underlying concept was to transform network users from passive to active subjects in the transmission expansion planning. The new regulation identified three possible methods for the authorisation of transmission expansion projects, which are presented below.

- Contract between parties: one or several parties propose to the transmission owner in the area an expansion of the network, outlining an O&M contract and technical details of the line, to be approved by the National Regulatory Authority (ENRE, *Ente Nacional Regulador de la Electricidad*). The investment costs are charged to the proponents and afterwards the line is treated as an already existing line.

- Minor expansions: a minor expansion is one that does not exceed a previously specified threshold investment. The incumbent transmission operator is in charge of such expansions. ENRE is in charge of determining the beneficiaries who will pay for the investment.

- Public Contest: a group of parties, called the "initiators", can identify an expansion project and propose to have a public contest to give it in concession, outlining an O&M contract and technical details of the line. All the data are presented to ENRE, which is in charge of checking that the benefits exceed the costs. Furthermore ENRE requires the System Operator to identify all the beneficiaries of the expansion (through the Areas of Influence Method, which is briefly described later in this document, when presenting cost allocation methodologies) and the share of investment that each of them should pay in case the line is installed. ENRE may only consider a request for which the initiators represent at least 30% of the "benefits" that the expansion would bring in its Area of Influence. If this condition is satisfied, all these figures are published and a hearing process is carried out; if 30% of the beneficiaries oppose to the expansion, then this is rejected. Otherwise a public tender is launched by the proponents, under the supervision of ENRE, and a constructor is selected. The amortisation of the investment is paid by all the beneficiaries, in the share identified by the System Operator, and not only by the initiators. After the amortisation expiration, the line is treated as an existing line.

As explained by Littlechild and Skerk (2004), while the Contract between Parties and the Minor Expansion were supposed to be used for projects benefitting just a small number of users alone or whose budget does not justify a complex procedure, the Public Contest method was supposed to be used for the main transmission expansion projects, involving large investments and benefitting many parties. The idea, based on the "beneficiary pays" principle, is that if the expansion costs are to be charged to a group of users because they are supposed to benefit from it, then those users would be willing to identify and propose such expansion projects[5].

3.1.2 Transmission remuneration

The remuneration of new transmission facilities is defined depending on the expansion planning methodology. In the case of the Public Contest, the remuneration is the outcome of the public tender to construct, operate and maintain the proposed expansion.

On the other side, the remuneration of the existing network is subject to incentive regulation. As in any other incentive-regulation mechanism, the fixed remuneration is to be complemented by a penalisation scheme.

The remuneration is calculated based on the allowed costs for each component of the existing network (lines, transformers, substations, etc.). These allowed costs only consider operation and maintenance and connections. According to Sanz (2004), no payments are assigned to

[5] The most important challenge that the new regulation had to face was the construction of the so-called Forth Line, connecting Comahue generation plants to Buenos Aires demand. See Littlechild and Skerk (2004) and Anderson and McCarthy (1999) for different evaluations of the regulation in place.

cover depreciation and returns of existing assets, because the State transferred them at no cost to the new transmission companies upon privatisation (sunk costs). Different revenue elements are used to calculate the remuneration for the following 5 years. Basically, they can be divided between fixed revenues (related to the charges defined to allocate the costs, described in the next section, Connection and Capacity Revenue), and variable revenues (Transmitted Energy Revenues).

3.1.3 Cost allocation

Transmission allowed costs are to be paid by the wholesale electricity market agents, i.e. generators, distributors (acting as regulated retailers for the captive consumers) and large users. The cost allocation is different for each revenue element used to remunerate transmission.

The Variable Network Revenues, originated by nodal prices considering losses and collected by the Market Operator (CAMMESA), are used to cover part of the so-called Transmitted Energy Revenue. Being these revenues generated by the difference in the short-term price paid to generation and the one paid by the demand, all market agents implicitly pay for it, according to their location and generation/load profile. Since the Variable Network Revenues can be subject to high volatility, this part of the transmission remuneration is paid in 12 monthly instalments that represent its expected average value. Any deviation of the actual Variable Network Revenue from the monthly instalment paid to the concessionaire is balanced through the so-called *Apartamientos* Accounts.

On the top of the quota of the Variable Network Revenues, the transmission concessionaire receives a Complementary Charge, which covers the Capacity Revenue plus any deviation between the Variable Network Revenues and the Transmitted Energy Revenue. This Complementary Charge is spread among network users through the so-called Areas of Influence Method, which assigns the share that each user has to pay for each line. The methodology, as explained in detail in Reta et al. (2005), is based on the marginal use of the network -also called marginal participations in Rivier et al. (2013)-. Unitary increases of generated or demanded power are successively applied in each node of the network. The area of influence of a specific node in which the increase was applied is the set of lines in which the corresponding power flow variation is positive. The final share of a user on a certain line is obtained through the average of its participation in all the states analysed, compared with the participation of the rest of the users. Marginal participations methods require the arbitrary fixation of a slack node, which, for the Argentinean system, is represented by Buenos Aires[6]. This methodology is also used for network expansion and it is at the base of both the identification of the beneficiaries of a new transmission facility and the allocation of the resulting costs.

A similar methodology is followed for the cost allocation of the Connection Charge, which covers the Connection Revenue. When transformation stations serve several users, the share assigned to each user is calculated on the basis of the peak capacity demand for the loads and the installed capacity for the generators.

3.2 Brazil

Among the countries analysed in this study, Brazil presents the largest transmission network, being also a meshed one. The main challenge of transmission regulation in Brazil is to

[6] Rivier et al. (2013) highlight the arbitrariness in the selection of the slack node as a flaw of the marginal participations method. However, these authors argue that in the Argentinean case the slack node is located in the very dominant load centre (Buenos Aires) and that this creates a system of charges for generators growing with the distance to the main load centre which is reasonable. The same situation is found in Chile, being Santiago the slack node.

guarantee the connection to the power system of the large amount of new generation that is being installed to cover the fast-paced demand growth, which is mainly composed by large hydropower plants located in remote areas.

3.2.1 Expansion planning

The expansion of the Brazilian transmission network is centrally planned by EPE (*Empresa de Pesquisa Energética*), a Governmental agency which elaborates two different studies:

- The Decennial Expansion Plan (*Plano Decenal de Expansão*, PDE), which analyses both the generation[7] and the transmission development with a ten-year time horizon.
- The Transmission Expansion Programme (*Programa de Expansão da Transmissão*, PET), which provides a more detailed planning, only relative to the transmission segment, for a five-year time horizon.

Nevertheless, the process is complicated by the peculiarities of the Brazilian energy market. As mentioned for example in Maurer and Barroso (2011), new generation projects are selected through long-term electricity auctions that fix the generator remuneration for a long period of time. The bids that potential project developers present in the tender have to take into account an estimation of the associated transmission charges that the new plant will have to pay. However, the transmission charges are the output of a planning process that needs the generation expansion as an input. This chicken-and-egg problem, typical of the transmission/generation expansion problem in a market environment, is addressed in Brazil through the following process:

[7] In order to provide some figures, for example, the PDE 2022 considers that between 2012 and 2022, more than 31.000 km of new lines will be installed (EPE, 2012)..

1. The PDE provides an indicative generation-transmission expansion plan.
2. Based on the projected transmission expansion and on the investment required to implement it, network charges are estimated and communicated to all the candidate generators considered in the long-term electricity auctions. If the generation projects are selected in the auction, the estimated network charge is fixed during all the project concession or authorization period, thus reducing the risk exposure of generation investors.
3. Once all the candidate generators know the estimated network charges, they can calculate their bids. The energy auction is carried out and the most-economic generation projects are selected and awarded a long-term contract.
4. Based on the outcomes of the auction, the actual transmission expansion planning is defined, which results in the publication of the PET. The construction of the necessary grid reinforcements is assigned through a competitive bidding process, where transmission companies bid for a revenue needed to build and operate the assets. This auction determines the actual costs of the expansion. Based on these costs, the actual network charges are calculated.

The deviations between the estimated and the actual network charges (positive or negative) are absorbed by electricity consumers, in proportion to their network charges estimated in step (2) above. Consumers have tariff cycles of 1-year and this is the mechanism used to permanently let them pay the actual transmission costs. All network costs are fixed charges ($/kW of installed capacity for generators or peak contracted load for consumers[8]).

[8] In the case of regulated consumers, the distribution company is responsible of pre-contracting the expected peak load on their behalf.

The PET resulting from step 4 has to be approved by the National Regulatory Authority, ANEEL, which launches a reverse auction for the construction of the grid reinforcements. The concession is awarded on the basis of the lowest annual rent charged by bidders for the construction and operation of the transmission facility. Each new selected bidder has to form a special purpose company for the project development, which later becomes a transmission company.

Local financing has been a key factor for transmission expansion in Brazil. The Brazilian Development Bank (*Banco Nacional do Desenvolvimento*, BNDES) is constantly financing transmission reinforcements. Standard financing period is of 14 years, with long-term interest rates and low spread risk. Financial guarantees to BNDES are based on the 30-year concessions at fixed allowed revenues that are assigned in the auction.

3.2.2 Transmission remuneration

Once the expansion planning is defined, the set of existing and projected transmission facilities to be remunerated within a given Tariff Cycle (TC) is known. In the context of remunerations and charges, the transmission grid is usually divided into:

- Basic Grid Facilities, i.e. transmission assets with voltage level equal to or above 230 kV, whose remunerations are recovered through a charge (TUST-RB, as explained in the next subsection) to be paid by all the Basic Grid users.

- Transformers with primary rated voltage equal to or greater than 230 kV also classified as Basic Grid facilities. The remuneration due to these assets is recovered through a charge (TUST-FR) to be paid exclusively by distribution utilities.

- Other Transmission Facilities, i.e. transmission assets not characterised as Basic Grid.

The vast majority of transmission costs are related to the Basic Grid Facilities. Therefore, here the attention is focused on the remuneration of these facilities and on the user charge collected to cover it.

The remuneration of transmission facilities is known as RAP (*Receita Anual Permitida* in Portuguese, the Annual Allowed Revenue). It is paid to the network owner for the entire duration of the concession (commonly 30 years) and it is periodically revised. However, the process is different depending on whether the facility is auctioned or authorised by the Regulatory Authority.

Auctioned transmission lines are those resulting from the expansion planning process detailed above. In the auction, the bids represent the RAP required by the different participants (ANEEL defines a cap for each tender). The winning project developer is therefore remunerated exactly through its bid. However, the auctioned RAP is adjusted each year to consider inflation and is subject to revision every 5 years. On the other hand, the five-year periodic revision is aimed at reflecting changes in the variable components of the costs incurred by the owner of the facility, i.e. debt costs and operation and maintenance costs.

Besides this kind of facilities, there are also transmission reinforcements, whose installation is directly required by EPE or by the System Operator, which are not auctioned, but authorised by the National Regulatory Authority and assigned to the incumbent transmission concessionaire. In this case, the RAP is calculated by ANEEL, based on its database of typical equipment costs and on a regulated rate of return. Also this RAP is adjusted every year to consider inflation. Nevertheless, the methodology applied to the revision of authorised facilities is different than the one applied to auctioned facilities. It is carried out every four years and comprises the assessment of operation and maintenance costs, regulatory asset base and capital remuneration.

3.2.3 Cost allocation

Once the total transmission costs have been calculated through the methodology presented above, they must be recovered from network users through the transmission charge. In Brazil, this charge is called TUST (*Tarifa de Uso do Sistema de Transmissão*, use-of-the-transmission-network tariff). The TUST is calculated through a methodology that aims at reflecting the long-term marginal costs for injections and withdrawals and at calculating different nodal charges in order to provide a locational signal. The methodology is fully described in Junqueira et al. (2007). They are applied as a yearly fixed charge, expressed as USD per kW installed for the generators and as USD per kW of contracted demand for the loads.

Unfortunately, these charges, calculated for each one of the nodes in the network, are not sufficient to cover all the transmission remunerations and to ensure cost recovery. Therefore, an extra postage-stamp charge, uniform for all the users, is added to the TUST. As a consequence, the locational signal in the final transmission tariffs is weakened.

3.3 Chile

Chile pioneered power sector liberalisations, with its reform dating back to 1982. However, the regulation of transmission, as for other segments, was modified by the so-called Short Laws I and II (Law 19.940 of 2004, hereafter SL-I, and Law 20.018 of 2005 respectively).

3.3.1 Expansion planning

The expansion of the transmission network was one of the main concerns of the regulator at the moment of drafting SL-I. As underlined by Rudnick et al. (2009), the original framework based on bilateral negotiations among the transmission owner and the interested parties did not provide transmission investment signals and lacked a common method to value and allocate the use of the transmission assets. This provoked free-riding by some agents. For this reason, transmission expansion and pricing was modified into a cooperative regulated scheme, with active participation of market agents.

First of all, the SL-I introduced a new subdivision of the transmission network into three systems, according to its beneficiaries:

- Trunk system (*Sistema Troncal*), which is defined as the whole of transmission installations of common use in the power system. It is essential for generators to sell their energy in the load centres and for distribution companies to supply their contracted demand. All the agents in the power sector benefit from its presence. The trunk system is characterised by voltages higher than 220 kV.

- Subtransmission system (*Sistema de Subtransmisión*), which is composed by those transmission facilities installed to supply a specific group of consumers which are located out of the trunk system. The subtransmission system benefits only those consumers whose demand is supplied through its facilities.

- Additional transmission system (*Sistema Adicional*), which is composed by those installations that are used by a single user (connecting to the system either a generation plant or a large consumer.

In the subtransmission system, the expansion planning is performed by the concessionaire, driven by the fulfilment of reliability standards. In the Additional transmission system, new investments are the outcome of bilateral negotiations. However, it is in the trunk transmission system where the main regulatory modifications were introduced by SL-I.

According to the National Regulatory Authority (CNE, 2005), every four years, an independent consultant is commissioned an expansion study. It considers different scenarios of generation development[9], nodal demand forecasting, fuel price projections, transmission projects proposed by the agents, and reliability criteria. The overall objective of the study is to identify an expansion plan that supposedly minimises the costs of transmission investment, system operation, and outages over a 10-year period.

This trunk system expansion plan must be revised on a yearly basis by the System Operators for the network under their control (in Chile, different System Operators are active in different interconnected systems). The revision compares the actual generation planning with the forecasted one and, through a consultation process that includes all the agents involved, identifies the necessary trunk transmission expansion projects. The information is communicated to the National Regulatory Authority (CNE), which is in charge, in a window of 30 days, of releasing the official expansion plan for the trunk system, defining the projects whose construction must begin in the following 12 months. Agents are allowed to express their discrepancies and an expert panel is called to resolve the dispute.

The official expansion plan released by the CNE divides the projects to be implemented into two different categories:

- New trunk transmission projects, which are considered as independent of the existing grid and whose construction is awarded through an international bidding process, centrally managed by the System Operator. The bid in the auction represents the sum of the investment costs plus operation and maintenance, while the rate of return is set by the CNE to 10%. The lowest bid is selected and used for the remuneration of the project developer during five tariff periods.

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[9] As in Brazil, also in Chile generation expansion is driven by long-term electricity auctions. For further details on electricity auctions in the region, see Maurer and Barroso (2011).

- Upgrades of the existing network, which consist in extensions of the grid that are interdependent with existing facilities. In order to guarantee a competitive price, the corresponding owner of the portion of the network to be expanded is required to launch a tender. In the CNE planning, a reference remuneration is specified for each upgrade and this value is introduced as a price cap in the auction.

3.3.2 Transmission remuneration

Trunk system tariffs for the existing network are determined every four years, in the framework of the transmission expansion study. While the remuneration of new transmission projects is the result of the auctioning process (the selected bid represents the annual remuneration required), the compensation for existing facilities is defined by an international consultant in the so-called Trunk System Study. As described in detail by Rudnick et al. (2009), the main steps of the process are as follows.

- CNE publishes the terms of reference of the study and launches a tender for its elaboration.
- The study is developed by an international consultant in an 8-month period. The elaboration is supervised by a committee composed by members from the CNE and from generation, transmission, and distribution companies.
- The results are published and presented to the public audience. After this, the CNE has 45 days to elaborate a technical report based on the results and considering the comments from participants.

The outcome of the transmission study is the identification of the assets belonging to the existent trunk system and the remuneration for each of them. Since the original liberalisation, the methodology implemented in Chile for the calculation of network compensation is the so-called New Replacement Value (*Valor Nuevo de Reemplazo* or VNR[10]). Applying a rate of return (which, for network activities, is fixed by the CNE also to 10%) over the life span of the asset (which is different for each asset), it is possible to calculate the Annuity of the Investment Value (*Anualidad del Valor de Inversión* or AVI). Besides the investment costs, the Trunk System Study is in charge of defining also the efficient Operation and Maintenance Costs (*Costos de Operación, Mantenimiento y Administración* or COMA).

The AVI + COMA value, together with the indexation formula for its yearly updating during the four-year tariff period, represents the yearly remuneration for each asset of the existing network.

3.3.3 Cost allocation

As in other South American power systems, part of the transmission remuneration is recovered from the market operation, through the application of nodal prices for congestion management. This part is called Tariff Income (*Ingreso Tarifario* or IT), but again it is not sufficient to cover the entire transmission costs. Therefore an additional transmission toll is introduced, which can be represented as AVI + COMA - IT. In order to define in advance this complementary charge, an estimated Tariff Income is considered for the future. Since the transmission remuneration must be fixed and equal to the value defined in the tariff study, any deviation of the real IT from the estimated one is then collected through a resettlement.

The transmission toll is collected from both generators and consumers. The part relative to the generation is called Injection Toll (*Peaje de Inyección*), while the part to be paid by loads is known as Unitary Withdrawal Toll (*Peaje Unitario de Retiro*). The allocation of the AVI +

[10] For a detailed explanation on monopoly regulation, see Gómez (2013).

COMA - IT between generation and loads is carried out through the Common Area of Influence method (*Área de Influencia Común* or AIC).

The AIC is defined as the zone within the trunk system where the largest portion (at least 75%) of the demand and of the generation is located and that accounts for the largest share of the unitary transmission cost. It represents the zone of the system corresponding to the main market, towards which almost all the generation is directed. Those facilities which are not part of the AIC are defined as Lateral Systems (*Sistemas Laterales* or SL). The cost allocation for these two separated areas follows different rules. As regards the facilities contained in the AIC, the assignation rule considers that 80% of their corresponding toll must be paid by the generation and 20% by the demand. On the other hand, the cost allocation for the Lateral Systems is defined according to the direction of the prevailing flows on the line. When the flow is entering the AIC, the cost of the facilities must be covered by the upstream generation. When the flow is leaving the AIC, the cost must be carried by the downstream demand.

The toll to be paid by generation and demand is finally spread within these two categories among all the users that compose them. This operation is carried out applying a marginal participations methodology (Rivier et al., 2013), which permits to assign to each user an expected contribution to the usage of the network.

3.4 Colombia

In Colombia, if compared with other systems in the region, the extension of the power system and the shape of the country result in a lower impact of the transmission network on the sector. This led to the implementation of a regulation of the transmission segment which is less complex than those analysed in the previous subsections.

3.4.1 Expansion planning

The expansion of the Colombian transmission network is centrally planned by UPME (*Unidad de Planeación Minero Energética*, i.e. Energy and Mining Planning Unit), which is in charge of delivering and adapting on a yearly basis a reference generation-transmission expansion plan. Nonetheless, a certain degree of involvement of the power sector agents is provided by the supervision of the CAPT (*Comité Asesor del Planeamiento de la Transmisión*, i.e. Advisory Committee for Transmission Expansion), composed by representatives of large consumers, retailers, and transmission companies and, with a minor share, of generators and distributors (CIER, 2013).

The methodology followed for the elaboration of the plan is based on a complex model that simulates the operation of the system under different scenarios and allows to identify restrictions. The input scenarios consider different forecasts of demand growth and fuel price behaviour, together with different generation expansion plans. The objectives that drive the transmission expansion plan are the reduction of congestion costs and the enhancement of the stability and the reliability of the system (UPME, 2013). This allows to identify candidate expansion projects through a cost-benefit analysis based on the simulation of the operation. These projects are finally prioritised considering three planning horizons: short term (5 years), medium term (10 years), and long term (15 years). The plan is updated and adapted every year.

The projects selected for implementation are then assigned through an international bidding process, open to foreign investors as well as to incumbent transmission companies. The bid in the auction represents the Annual Expected Income (*Ingreso Anual Esperado*), which has to cover all the costs incurred by the selected agent. The Annual Expected Income will be the remuneration of the transmission facility during 25 years, after which the asset is remunerated as the existing network.

3.4.2 Transmission remuneration

The remuneration of the transmission network is different for facilities installed before 1999 (existing assets) or after 1999 (new assets, or tendered assets).

As regards existing assets, the income is administratively defined as the sum of two components, one related to the investment costs and one concerning operation and maintenance costs. The annuity remunerating the investment costs is calculated through the New Replacement Value of the assets. The latter is based on standard unitary costs for the equipment, different life span for different assets, a regulated rate of return calculated through the WACC methodology (11.5% from 2008 on), and an indexation formula. The income is indexed and settled every month. The annuity is calculated once and it is not modified unless the National Regulatory Authority modifies the unitary costs or part of the asset is replaced by the transmission owner. On the other hand, operation and maintenance costs are remunerated through incentive regulation. In fact, every year the transmission owner is recognised the O&M costs accounted for the previous year (excluding some cost items not subject to cost reduction). This provides it with an incentive to reduce its costs in order to retain a profit from the fixed revenue. However, the NRA requires an audit carried out by an external consultant for each transmission company, in order to verify the information it provides. Operation and maintenance costs are expressed as a percentage of the annuity recognised to the transmission facility.

As concerns tendered assets, the annual income is determined as an outcome of the bidding process for the construction of these facilities. It must include investment and O&M costs as well as the required rate of return. The remuneration resulting from the auction is applied for 25 years.

3.4.3 Cost allocation

In Colombia, congestion management and transmission losses are managed through re-dispatch and loss factors, thus no Variable Network Revenue is generated. Therefore, the transmission costs are to be entirely covered through a complementary charge. The methodology used to allocate this complementary charge is a “postage stamp” to be paid only by the demand. Both regulated (captive demand) and non-regulated (free demand) users have to pay a monthly usage charge.

The basis for the charge calculation is the so-called Regulated Monthly Income (*Ingreso Regulado Mensual*) calculated as the sum of all the monthly remunerations due to transmission facilities, both existing and tendered assets. The Regulated Monthly Income is divided by the total monthly demand, as communicated by retailing companies, and a basic charge is obtained. The latter is charged directly to regulated users, while for free demand a further hourly differentiation is applied. Three different demand periods are identified during the day and a different charge is calculated for each period. This scheme aims at creating a tariff that sends economic signals to non-regulated users for them to shift their loads from high- to low-demand periods. The monthly usage charges are the same for all the system, regardless of the location and the voltage level of the withdrawal.

3.5 Peru

According to the original Peruvian Electricity Act (*Ley de Concesiones Eléctricas*, no. 25.844 of 1992), investment in new facilities was to be the outcome of the decisions of market agents and no centralised expansion plan was considered. However, this approach did not result in a sufficient expansion of the grid. In order to reform the segment, the Regulator commissioned a white paper from a committee of experts. The guidelines presented in the white paper (ME, 2005) proposed the establishment of a long-term transmission plan to be elaborated every other year, and to assign the expansions considered in the plan through competitive auctions. As regards cost allocation, the committee of experts suggested to use two different methods: average participations for the existing facilities and a beneficiary-pays method for the new assets. Furthermore, they underlined the importance of setting the transmission charges ex-ante and for a long number of years, in order to provide a robust locational signal to generators and to reduce their investment risk. Some of the recommendations were implemented, while others were disregarded due to the complexity of their application. The new regulatory framework was introduced by Law 28.832 of 2006, whose contents are analysed in the following subsections.

3.5.1 Expansion planning

The different laws that regulate the transmission segment in Peru have resulted in a four-category distinction of the network. Originally, Law 25.844 divided the transmission grid according to the main users of the lines.

- Main Transmission System (*Sistema Principal de Transmisión*, or SPT), , where no dominant flow can be identified.
- Secondary Transmission System (*Sistema Secundario de Transmisión*, or SST), composed by those facilities whose goal is mainly to move electricity from the SPT to a generation plant or a load located outside it.

Nevertheless, Law 28.832 modified the regulation through the introduction of a binding Transmission Plan (*Plan de Transmisión*), to be elaborated periodically. The plan is prepared by the System and Market Operator (COES) and must be approved by the Ministry of Energy and Mines (MINEM), under the supervision of the National Regulatory Authority (OSINERGMIN). The Transmission Plan identifies the expansion projects to be carried out during the following 10-year time horizon and divides them in two groups, which compose two systems regulated differently:

- Guaranteed Transmission System (*Sistema Garantizado de Transmisión*, or SGT), composed by those assets contained in the Transmission Plan and whose installation benefits all the users of the interconnected system. The remuneration of the assets belonging to the SGT is collected through charges to all the users.
- Complementary Transmission System (*Sistema Complementario de Transmisión*, or SCT), composed by those facilities contained in the Transmission Plan, whose construction benefits an identifiable group of users and whose remuneration is to be paid only through charges from this group of users.

The expansion projects identified in the Transmission Plan are assigned through an auction for awarding a 30-year concession contract. The Ministry of Energy and Mines can either call the auction on its own or commission the entire process to the Agency for Promotion of Private Investment (PROINVERSIÓN). However, in case the expansion project represents a reinforcement of the existing grid, preference for its execution is given to the incumbent transmission company (in this case no tender takes place and the remuneration is the outcome of a bilateral negotiation with the NRA).

Expansion projects not included in the Transmission Plan, but which are considered as beneficial by a group of investors for their economic activities, can be developed, if authorised, as private initiative, then forming part of the Complementary Transmission System.

Apart from the Transmission Plan, every transmission concessionaire has the obligation to elaborate every four years the so-called Investment Plan (*Plan de Inversiones*), which must identify, with a 10-year horizon, the reinforcements on the network required to comply with the reliability requirements. Once the plan is issued by the concessionaire, it must be approved by the NRA. Also these facilities, once installed, become part of the SCT.

The first subdivision (SPT/SST) was not cancelled by the second one (SGT/SCT). Therefore, at the moment, four different subsystems, with slightly different cost recognition and allocation methodologies, coexist within the Peruvian interconnected system.

3.5.2 Transmission remuneration

The transmission remuneration has to be analysed separately for each one of the above-mentioned subsystems.

The remuneration of facilities belonging to the Main Transmission System (SPT) is defined by Law 25.844. The assets belonging to the SPT are compensated for the investment costs and the operation and maintenance costs. Investment costs are considered through an annuity calculated through the New Replacement Value of a minimum-cost grid identified by an optimisation model. The annuity is calculated considering a 30-year life span and a regulated rate of return fixed by the Law at 12%.

As concerns the Secondary Transmission System (SST), the compensation is defined once and is represented by the so-called Average Annual Cost (*Costo Medio Anual*), which contains investment and O&M cost. The former is calculated using a database of standard equipment costs. The latter is determined as a percentage of the investment costs (the percentage is updated every 6 years). After its first definition, the Average Annual Cost is updated yearly through an indexation formula set by the NRA and it is modified only if some reinforcement required by the Investment Plan is approved.

The remuneration of the Guaranteed Transmission System (SGT) is defined by Law 28.832. It must include the recovery of investment and operation and maintenance costs, plus settlements due to the deviation from the expected compensation (due to the presence in the remuneration of the Variable Network Revenues). In the case of projects assigned through a competitive bidding process, the remuneration for investment and O&M costs is determined by the bid of the selected transmission agent.

Also in the Complementary Transmission System (SCT), the compensation is defined by the Average Annual Cost. The only difference is that investment costs are not calculated through standard equipment costs, but rather they are outlined by the Investment Plan approved by the NRA.

3.5.3 Cost allocation

As mentioned above, part of the remunerations calculated for the different systems through the methodologies just presented can be recovered from the so-called Tariff Income, which, in Peru, represents the difference in electricity prices between the withdrawal and the injection nodes. Nonetheless, again the Tariff Income is not sufficient to cover all the costs and an additional toll must be applied to network users. The allocation of this toll varies depending on the system and is presented herein with the same subdivision.

As regards the SPT, the difference between the total main transmission costs and the Tariff Income is called Connection Toll to the SPT (*Peaje por Conexión al Sistema Principal de Transmisión*). The Connection Toll is fixed once a year and it is updated monthly to reflect inflation and changes in the currency exchange rate (between Peruvian Soles and US dollars). The Unitary Connection Toll is calculated as the ratio between the Connection Toll and the maximum demand to be supplied and it is paid by the consumers according to their contracted demand, with a postage stamp approach.

The SST system is defined by the possibility of clearly identifying the beneficiaries of the transmission facilities that compose it, according to the dominant flow from or to the SPT.

The cost of these assets is then to be recovered completely through charges to the beneficiaries, either generators or loads.

As concerns the SGT, the difference between the total guaranteed transmission costs and the Tariff Income takes the name of Transmission Toll for the SGT (*Peaje de Transmisión del Sistema Garantizado de Transmisión*). Also in this case the Transmission Toll is divided by the demand to be supplied and the resulting unitary charge is added to the power busbar tariff.

As regards the SCT, the NRA is in charge of defining a demand area of the transmission system where most of the benefits deriving by the installation of the SCT facility are observable. The SCT Transmission Toll (difference between the Average Annual Cost and the Tariff Income) relative to each facility is then recovered as a postage stamp among the consumers located in the demand area.

3.6 Comparison

The regulations of the transmission segment introduced in the previous section for the five countries analysed in this paper present several similarities, testifying the regulatory "contamination" in place in the region, but also relevant differences. The regulatory frameworks presented in this paper are compared, following the structure used in this document, in Table i.

Table i. Comparison of transmission segment regulations among the five countries analysed in this paper

		Argentina	Brazil	Chile	Colombia	Peru
Network expansion	Expansion planning	Contract between parties or Public contest	Centralised planning coordinated with energy auctions	Cooperative regulated planning ("market planning")	Centralised planning	Centralised planning for expansion (decentralised for reinforcements)
Transmission remuneration	Variable Network Revenues	Part of the transmission remuneration	Collected but retained by the generation segment	Part of the transmission remuneration	Not collected	Part of the transmission remuneration
	Costs determination for existing facilities	Only O&M costs are remunerated	Administratively set based on standard equipment costs	Administratively set based on new replacement value	Administratively set based on new replacement value (incentive regulation for O&M costs)	Administratively set based on new replacement value
	Costs determination for new facilities	Based on a competitive bidding process launched by the proponents (Public Contest)	Based on a competitive bidding process	Based on a competitive bidding process	Based on a competitive bidding process	Based on a competitive bidding process
Cost allocation	Cost allocation	"Areas of Influence" Method	Long-term marginal costs complemented by postage stamp	"Common Area of Influence" Method	Postage stamp	Postage stamp for SPT/SGT, "beneficiary" methods for SST/SCT
	Generators pay?	Yes	Yes	Yes	No	No (SPT/SGT) Yes (SST/SCT)

4 CONCLUSIONS AND REGULATORY PROPOSALS

This article has presented the innovative solutions that have been implemented in South America to regulate power transmission. These regulatory mechanisms, even if far from being flawless in some aspects, represent a source of relevant guidelines for the elaboration of robust transmission regulation not only in South America, but also in other regions of the world. This is of particular importance in the current framework of sustained integration of large-scale renewable generation, which will be the main challenge of the transmission regulation in the near future, especially in the United States and in Europe. A remarkable study on the future of electricity grids (MIT, 2011) identified some principles that should be followed in the elaboration of a transmission regulation capable of facing the above-mentioned challenges. It is interesting to observe how several of these principles were already applied in the South American continent. These concepts represent the actual lessons worth learning from the South American regulation and are summarised in these conclusions, following the same structure used in the review.

4.1 Expansion planning

As regards expansion planning, the economic benefit should be the main driver for network investments and it should also be used to prioritise and rank different transmission projects. The economic benefit is to be measured as the increase in consumer surplus plus generation profits and can encompass also other planning criteria, as reliability. Applying, whenever possible, the "beneficiary pays" principle to network expansion, it could be inferred that network users are the agents who can more easily estimate the economic benefit of a new line, weighing their estimated charges derived from the investment costs involved against the expected benefits. Therefore, network users are also the agents who can more easily identify a beneficial expansion project and they should be entitled of proposing grid reinforcements. This is what happens in Argentina with the Public Contest method, in which the initiative is completely left to network users. An intermediate and highly recommendable solution, between the traditional centralised planning and the Public Contest, is to make the expansion planning as consultative as possible, involving all network agents from the very beginning of the process, as it happens for example in Chile.

4.2 Transmission remuneration

In terms of transmission remuneration, the most important lesson from the South American experience is the widespread application of competitive auctions for the selection of project developers and the definition of the remuneration. Competitive tenders are used in all the countries analysed in this article. In most of the cases, auctions are used not only to assign the construction work, but rather to select directly the concessionaire of the new line. This scheme is based on the regulatory model in place in all these countries, i.e. an Independent System Operator (ISO) that can operate networks owned by different agents. In case a Transmission System Operator (TSO) model is in place, as in the vast majority of European countries, competitive bidding should be used at least for the assignation of construction works. An issue related to transmission auctions is the financing of network expansion. In order to lower the interest rate required by potential project developers, so as to reduce the bids in the auction, some countries provide access to finance lines with below-market interest rates. This is the case of the soft loans offered by the Brazilian Development Bank to transmission investors willing to bid in an auction.

4.3 Cost allocation

As regards cost allocation, two very relevant guidelines can be extracted from the regulatory solutions presented in this article. The first one is the application of the "beneficiary pays" principle, according to which transmission costs should be allocated in proportion to benefits. This fundamental concept, often rejected by some power system regulators in favour of a simpler "postage stamp" approach, is at the base of the cost allocation methodologies applied in Argentina and Chile ("Area of Influence" methods) and in Brazil (long-term marginal cost of transmission), discussed in Junqueira et al (2007). The implementation of the "beneficiary pays" principle implies that transmission charges must be paid also by generators and that the charge will not be uniform for all the plants, because it depends on the network node. The locational signal provided by such transmission charge is essential for an efficient generation siting, and it is currently absent in most of European regulatory systems.

The second cost-allocation guideline, which corresponds to one of the driving principles for transmission regulation identified by Rivier et al. (2013), is that transmission charges should be established ex-ante and not updated for a large number of years. In fact, for the above-mentioned locational signal to be effective, networks users (and in particular generators) should know in advance the transmission charge they will have to pay and they have to be guaranteed that this charge will not vary. This reduces the uncertainty on future cash flows, thus lowering investment risk and fostering new generation investments. This approach has a clear example in the Brazilian context, where transmission charges are determined based on an indicative generation-transmission expansion plan before the auction for new generation takes place, thus allowing generation investors to calculate their bid knowing in advance which transmission tariff they will be charged.

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