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Transmission pricing in privately-owned electricity grids: An illustration from the Argentine electricity pool ☆

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Abstract

The Argentine electricity reform of 1992 offers an interesting example of decentralized transmission pricing arrangements within a competitive system. This paper is a shortened version of an original analysis made in 1994 of the regulation of the Argentine transmission system, with emphasis on investment cost allocation rules. To make up for the limitation of short-run marginal cost (SRMC) pricing, incentives on service quality were put in place, including penalties for lack of line availability. The mechanism for capacity expansion, based on ad-hoc rules for allocations of investment costs, had the potential to produce non-optimal investment outcomes, as such rules ignored beneficiaries on the demand side. For fine tuning of this system, I proposed an alternative rule based on traditional welfare analysis that broadens the universe of identified beneficiaries, and thus can be expected to produce a fairer outcome on investment cost allocation, reducing the potential risks of non-optimal investment. A brief postscript comments on the paper from the perspective of 2007.

JEL: L51; L94

Keywords: Electric utilities; Transmission pricing; Electricity pool; Argentina; Privatization

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1. Introduction

Pricing of electricity transmission grids is a challenging subject, due to the presence of economies of scale and density, lumpy investment, and the requirement to continuously keep the network balanced. There exists a demand for regulation not only for protecting grid users from the exercise of market power, but also for guaranteeing certain conditions of system reliability.

Reliability appears as a special ingredient in the operating efficiency of a transmission network. Other transmission characteristics include features such as minimizing distances between generation and demand sites, controlling load patterns, supplying emergency and security responses, coordinating maintenance, and managing operating reserve. All these special characteristics should be seen as services provided by the transmission activity. The main difficulty, both for the firm and for the regulator, lies in pricing these services, as they are quite cumbersome to cost out.

In this paper the pricing regime in electricity transmission established in Argentina in 1992 is described and analyzed, with emphasis on the problem of the investment decision. The high-voltage national grid is owned and operated by a regulated private firm in an electricity market where generation is competitive and, like distribution, is separated from the transmission activity. Regulation is rooted in five basic premises: monopoly rights to operate the existing grid, prohibition on the grid operator selling or buying energy, the open access principle[1], periodic competition for concession rights, and high-powered incentive regulation on prices and quality. The grid owner has not been given the obligation to expand capacity. Instead, a special mechanism has been designed to finance the construction of new lines.

The Argentine system has some powerful features as well as some shortcomings. For example, to make up for the implicit shortcomings of short-run marginal cost (SRMC) pricing, regulation has usefully been complemented by incentives on service quality. On the other hand, the mechanism for capacity expansion misallocates the costs of financing new investment, as it implicitly ignores basic welfare effects; in particular, it fails to identify the demand side as part of the beneficiaries of a new project. This could result in deviations from the optimal investment path in transmission, and I thus propose an alternative mechanism based on traditional welfare analysis.

The paper is organized as follows: the Section 2 summarizes the conceptual framework for setting transmission prices in decentralized networks, as known in the early nineties. In Section 3 I highlight the main features of transmission pricing in the Argentine transmission activity, and provide an early assessment as to its main features and incentives for efficient operation. In Section 4, I introduce the reader to the original mechanism to finance capacity expansion in Argentina, and I propose some guidelines for an alternative scheme. Finally, Section 5 presents some concluding remarks. This is followed by a brief postscript.

2. Transmission pricing and incentives background

2.1. Price levels

Transmission prices are not separable from conditions in the market of the product being transported (Hunt and Shuttleworth, 1993), as demand for transport is derived from supply and demand in product markets.

[1] For more about the open access principle and the regulation of essential facilities, see Tye (1987).

The following elements should be looked into to set transmission prices on existing capacity:

1. Line losses.
2. Operating and maintenance costs.
3. Redispatching generation costs.
4. Congestion costs.
5. Network quality of supply (line reliability).
6. Power system security issues.
7. Revenue reconciliation (budget constraint).

Line losses can be seen as the cost of replacing the power lost during transmission. The main source of line losses is the loss of heat from conductors and the reduced real-power transfer capability due to line reactance. These losses depend on line voltage, distance, and loading. Line losses increase with length and loading. The latter is an exponential function of losses, while distance follows a linear relationship. Additionally, the higher the voltages the lower the losses, *ceteris paribus*.

The cost of generation redispatch is a system adjustment cost. It can be measured by the additional generation costs that must be incurred at certain times if generation plants must be redispatched to maintain acceptable line flows (Schweppe et al., 1988). These costs depend on the type of generation units and other conditions of supply and demand. Both line losses and redispatching generation costs can be positive or negative. Line losses have this characteristic depending on the direction of the power flow.

Congestion costs occur when the transmission capacity is too small to meet all demands, so additional transmission can only be provided by restricting service to some party. Because of the transmission constraint, the marginal cost of generation of an integrated system increases. The difference in generation marginal costs attributable to the constraint can be considered as a measure of the congestion cost.

Line reliability is also known as the quality of supply component or the capacity component of the network. Reliability can be seen as a constraint in a cost-minimizing problem, or it can also be understood as an identifiable service within a bundle of transmission services[2]. System security issues include items like load-frequency control, reactive power support, maintenance timing and coordination, emergency responses, and reserves management, and are also called secondary transmission services.

Revenue reconciliation, in turn, is often needed to allow average revenue to cover short-run average costs, a consequence of economies of scale in transmission. The revenue reconciliation component of marginal cost pricing is usually a controversial issue in the determination of transmission prices, as there exists uncertain and asymmetric information. The determination of a revenue reconciliation charge may result in an overall price level that is too low to cover costs or too high, allowing for super-normal economic profits.

2.2. Price structure

The price structure may recognize different types of transmission services. Einhorn (1990) identifies at least three kinds of transmission demands: native, firm, and non-firm[3]. The last two

[2] Line reliability goals should be evaluated *vis-à-vis* society's preferences about power outages events.

[3] Using Einhorn's definition, native demand would be the demand for transmission capacity that is required to meet the buyer's native loads, whereas firm demand refers to reserved power and non-firm to unreserved power. See Einhorn (1990) at page 12.

categories can motivate different prices or special contractual agreements between parties. For example, one way to differentiate transmission services is to issue transmission rights for access. The existence of long-term contracts for the right to access requires the creation of a secondary market in transmission rights, which typically has the major problem of having a noncompetitive structure (few buyers and sellers). Compensation devices should also be developed whenever transmission is denied to users under firm contracts. In a different type of contractual agreement, effective prices could also differ when contracts to hedge parties against uncertainty and volatility in transmission prices are allowed. Hogan (1992) and Pérez Arriaga (1992a) have studied several ways of carrying out long-term transmission price insurance contracts.

Another element in the price structure comes from the nature of the relationship between the transmission company and its users. Schweppe et al. (1988) suggested that prices may vary depending on whether the transmission utility has an obligation to serve buyers and sellers. It is expected that when the transmission company has this obligation, the user will participate in the financing of the company's capital costs, thus facing higher prices.

In addition, there are price differences that arise as a consequence of the recognition that transmission services cannot be treated as a homogenous product. As Joskow (1993) stated:

> "…transmission service is not just a simple service involving the transportation of electrons from one point to another, but rather a bundle of services whose costs depend on the nature of the services provided, including the locations of generators and loads within the network."

Price differences not attributable to service heterogeneity, or price discrimination, can also be observed. Lack of transparency in transmission contracts usually favors the practice of price discrimination against poorly informed customers.

2.3. Capacity expansion

The need for a revenue reconciliation charge may not appear only to cover short-run average costs, but also to enable the firm to generate internal funds for new investment. Efficiency in the long-run should follow a fundamental rule, which is: the marginal cost of generating electricity at any two locations should differ by no more than the marginal cost of transmitting electricity between them.[4]

To promote long-run efficiency in the optimal amount of transmission and generation capacity, some authors have suggested other investment rules. Pérez Arriaga (1992b), for example, argues that the optimal investment rule should be:

> "…to invest in the network in order to reduce as much as possible the operation costs of the system, but only until the incremental cost is smaller than the resulting savings in operation expenses."

For Hunt and Shuttleworth (1993), the decision for building new lines at all is given by the rule that:

> "…total savings in generation costs must exceed the total cost of transmission, including construction and losses."

[4] See, for instance, FERC (1989), and Kelly et al. (1987).

The authors end up advocating that there should be investment as long as short-run marginal costs (SRMC) exceed long-run marginal costs (LRMC). Alternatively, Brown et al. (1989) call for the concept of long-run incremental cost (LRIC), as opposed to LRMC. While the latter is a static concept that compares optimal states (before and after an expansion takes place), the former introduces the dynamics of capacity increments within a certain time horizon.[5]

3. Transmission regulation in Argentina

This section briefly introduces the reader to the main features of the new economic organization that emerged from the unbundling and privatization of the power sector in 1992, for a better understanding of the incentives related to transmission investment in Argentina. A presentation of the regulatory features about the existing capacity of the national grid follows, and an assessment of these features concludes the section.

3.1. Unbundling and privatization

Before the massive privatization move started in 1992, the electricity industry (which represented 1.7% of GDP in 1990) was composed of five state-owned enterprises (SOEs) at the federal level, several provincially owned utilities, cooperatives and hundreds of small self-generators. Most of Argentina's 23 provinces have their own public integrated electricity utility that sets financial rules and tariffs for end-users. There were also 607 small cooperatives under concessions agreements granted by provincial governments, which provided distribution services in their areas, usually in isolated regions of the country.[6]

Electricity companies are interconnected through a national network system called NIS (National Interconnected System), which connects the majority (>90%) of generation sources in Argentina. The main primary sources of energy for electricity production are thermal – diesel and gas – (46%), hydro (37%) and nuclear (14%). Total power flows within NIS reached 53,500 GWh in 1993.

After privatization, three of the federal SOEs basically disappeared[7], turning into three distribution companies in the metropolitan area of Buenos Aires, one high-voltage transmission company operating at the national level, several regional transmission firms, and thirty private generators. The structure of the industry changed dramatically in the competitive direction. In 1991, five SOEs dominated 74% of the generation market (measured by installed power capacity), whereas by August 1993 the share of the top five had diminished to 34.4%. The major generation unit, which by 1993 was private, had a market share of less than 8%.

The national transmission company was named Transener SA (henceforth, Transener) and was privatized in July 1993. Sixty-five percent of shares (51% class A and 14% class B) were sold for US$ 234 million to a consortium formed by domestic (45%) and foreign (55%) shareholders[8]. Ten percent of shares (class C) were transferred to employees and the Government kept the rest (class B) with the expectation of future sale or flotation. Transener operates a network of 6867 km of 500 kV lines, 284 km of 220 kV, and 27 transformers.

[5] For a presentation of the different methodologies for calculating LRIC in the industry see also Teplitz-Semblitzky (1992).

[6] See Bastos and Abdala (1993).

[7] The federal state is still responsible for nuclear facilities (CNEA) and two bi-national hydro electrical concerns, Salto Grande (with Uruguay) and Yacyretá (with Paraguay).

[8] The original foreign owners were National Grid Company, Duke Corporation, and Entergy.

3.2. Transmission regulation of existing capacity

The Electricity Act defines electricity transmission as a public service, and the regulation of the privately-owned transmission company (Transener) is rooted in five basic premises:

a. Monopoly rights to operate existing network.
b. Prohibition from selling or buying energy.
c. Open access principle.
d. Periodic competition for the concession rights.
e. High-powered incentive regulation on prices and quality.

3.2.1. Operating rights and obligations

Transener received exclusivity rights to operate the high-voltage network. As a grid operator, it must focus on the provision of transmission services only and thus it is not allowed to sell or buy electricity in the marketplace. This ban is set to avoid indirect forms of vertical integration that may prevent competition in generation, to sidestep discriminating actions by the grid operator, and to prevent cross-subsidies between activities. The controlling group of Transener is also banned from holding a majority stake in generation, distribution or industrial user companies.

Transener has been required to provide transmission access to all parties (open access principle) when capacity is available. If capacity constraints arise, Transener cannot discriminate through rationing devices, since the system administrator, CAMMESA, – and not Transener – is the institution that decides which generator is called upon. This decision is based on an unconstrained dispatch merit list, which sorts producers by their recognized fuel costs. The dispatch mechanism makes rationing for transmission capacity optimal for the system as a whole, as it guarantees that the lowest-cost generators have access priority.

3.2.2. Competition for concession rights

The duration of Transener's concession lasts for 95 years, though it is divided into performance periods of 10 years each[9]. At the end of each performance period the government is scheduled to call for a public tender for the sale of the majority stake of class "A" shares (51% of total company shares). The incumbent has a slight advantage in this tender, as all competing bids have to be compared to its own statement about the value of the company (submitted in a closed envelope before the bidding date). If none of the offers exceeds the incumbent reference price, the concession rights do not change hands. Otherwise, the group offering the highest bid pays this value to the incumbent and obtains the concession rights.

At the end of the 95-year period the government changes the legal status of the company to a new public corporation, and offers its shares in an international public tender. All parties receive equal treatment and the proceeds of the sale are used to reimburse the last concessionaire. The whole mechanism of periodic competition for the concession rights gives the incumbent the incentive to preserve the value of the assets under concession, dampening the traditional negative effect of franchising contracts with asset-reversion clauses[10].

[9] With the exception of the first period, which lasts for 15 years. See Transener (1992).
[10] For more references on this subject see, for example, Dnes (1991).

3.2.3. Incentive regulation on prices

Transener is subject to both price and quality incentive regulation. There are five main components in the regulated pricing scheme intended to remunerate the existing capacity[11]:

1. Line losses
2. Line reliability
3. Congestion costs
4. Access charges
5. Revenue reconciliation charges

3.2.3.1. Line losses. For each line, revenue from line losses is calculated as the difference between quantities transported, evaluated at nodal prices for each of the two nodes involved. Nodal price (P_{n}) is the market price (P_{m}) defined at an arbitrary point of the grid – called the market center, – affected by a nodal factor (F_{n}), as shown in Eq. (1).

$$P_{\mathrm{n}} = P_{\mathrm{m}} F_{\mathrm{n}} \tag{1}$$

A nodal factor is related to the derivative of line losses (dL) with respect to loading (dB) at node i, such that

$$F_{\mathrm{n}}^{i} = 1 + \left(dL/dB^{i}\right). \tag{2}$$

Revenue from line losses (LL) is therefore calculated as

$$\mathrm{LL} = E^{r}P^{r} - E^{d}P^{d} \tag{3}$$

Where E^r is the energy flow at reception node r, P^r is the nodal price at that reception point; E^d is the energy flow injected at delivery node d, and P^d is the price at that node. Nodal prices can then be expressed in terms of the market price, P_{m}, as

$$\mathrm{LL} = P_{\mathrm{m}}\left(E^{r}F^{r} - E^{d}F^{d}\right) \tag{4}$$

3.2.3.2. Line reliability. Reliability of the line, also referred to as network quality of supply, is paid through the spatial difference between the remuneration that buyers pay for active power reserves (D) and what sellers receive for this concept. The spatial difference is introduced through the concept of a so-called adaptation factor (A). An adaptation factor for node i has been defined as a function of D, and of historic overrun costs caused to the pool due to line failures (O) associated to that node, such that

$$A^{i} = 1 + \left(O^{i}/D\right) \tag{5}$$

The remuneration for line reliability (LR) is then collected indirectly through the total difference between what buyers pay and what sellers receive for D (adjusted by their respective adaptation factors)[12].

[11] Other charges would involve many of the secondary transmission services mentioned in the previous chapter (see system security issues), which are afforded directly by the grid users. Such is the case of reactive power support, load-frequency control, and operating reserve management.

[12] The remuneration for active power reserves, D, is paid during weekday time, except for valley hours.

Notice that both LL and LR are revenue components with a high volatility, as they vary every hour according to actual dispatch conditions. To account for this volatility factor, a revenue stabilization mechanism was devised to settle payments accruable to Transener. Every five years, the regulatory body, ENRE, makes an estimate of the annual value of LL and LR, and Transener's revenue from these two concepts is based on these estimates. Grid users, on the other hand, pay for the realized values emerging from LL and LR. The difference between estimated and realized values is accounted for in an additional price component called a complementary charge, which will be described below.

There is another element that can be considered as a line reliability component in the general remuneration to the grid. When CAMMESA announces that either transmission or generation constraints forecast an overall supply shortage equivalent to 0.7% of total estimated demand or larger, then the pool is declared under the status of "loss of load risk". When this happens, there is an overcharge or special bonus to the basic remuneration of energy and power reserves. This bonus, which is set as a function of the cost of loss of load, raises the remuneration of LL and LR through the increase of multipliers of P_{m} and D. The increase in the remuneration of LL and LR can be classified as remuneration associated to line reliability when the loss of load risk status is caused by a transmission constraint.

3.2.3.3. Congestion costs. No attempt was made to explicitly set a price component for congestion costs, which is indeed very volatile, and difficult to calculate on a real-time basis. However, nodal prices do vary when there are partial or total constraints on the transmission capacity. When there is a physical constraint on a line, CAMMESA declares the status of "isolated area" to the constrained region and local prices replace market prices in that area. To avoid speculative moves by generators, both market and local prices are determined under the same dispatch merit list prevailing before the constraint. The market price could rise though, if there were power flows coming from the isolated area that has to be replaced by less-efficient generation from elsewhere in the market. As Eq. (4) showed, the increase in the spot price, $P_{\mathrm{m},}$ will translate into higher LL in all unconstrained lines of the network, and this mechanism is indeed an implicit way to remunerate congestion costs. Congestion costs thus appear indirectly through the differential in generation marginal costs.

3.2.3.4. Access charges. Access charges are unit charges for each interconnection point with the grid, and are intended to remunerate the costs associated to transformation stations at these points. These charges would probably fall into the category of what Pérez Arriaga (1992b) called operating and maintenance costs of transmission facilities that are attributable to a specific user, or a reduced group of users of the network. The Government set the level of the access charges before the privatization of Transener and its regulation follows an RPI-X regime. In 500 kV lines, the access charge was set at US$ 10 per hour. The efficient parameter X is zero for the first five years, and from then on it will be set by the ENRE. Its value cannot exceed 1%.

3.2.3.5. Revenue reconciliation charges. Under what would be a revenue reconciliation component, the pricing regime for transmission services included what was labeled as complementary charges. These charges have two components. The first one is the so-called transmission capacity charge, which is a per-hour value based on line usage[13]. To account for usage among various

[13] The value also varies proportionally to distance, and slightly decreases with voltage. For 500 kV lines it was set at US$ 48 per hour per 100 km.

customers, weights are determined according to each user load, measured at the system peak. The level of the transmission capacity charge was also established before privatization and its variation is subject to RPI-X regulation, in the same fashion as access charges.

The second component of complementary charges is the difference between realized and estimated charges for LL and LR that emerges from the stabilization scheme that protects the transmission company from spot prices volatility. Complementary charges are prorated among customers under the same methodology chosen for deciding users' share in the pool of beneficiaries of a new line, which will be explained below.

3.2.4. Quality requirements

Notice that there are two elements in the pricing regime, LL and LR, which send correct price signals to grid users, but have a perverse effect on the behavior of the grid owner. Indeed, the higher the losses and the lower the reliability of the line the higher the grid company revenue[14]. To counteract this negative signal on transmission quality, Transener was given special incentives to maintain full availability over the whole network. Transener pays penalty charges whenever lines are unavailable[15], and receives bonuses when its availability performance is outstanding.

Penalties for lack of availability have been set on a per-line basis and their level is a function of access and transmission capacity charges. Their size increases with the duration and frequency of line outage, voltage, and by a fraction of the overrun costs caused in the system due to the transmission failure.

Line availability is not the only regulated quality indicator. Among other quality requirements, it puts emphasis on the regulation of voltage levels – which should not exceed a pre-established range – of reactive power equipment, transformation stations, and other operative and configuration issues.

3.2.5. An assessment of current regulation over existing capacity

Although transmission pricing at SRMC sends the correct spatial signals to grid users, there is a demand for complementary regulatory measures. In the Argentine pool, examples of such measures are the set of incentives for service quality, the stabilization mechanism to cope with price volatility, and the revenue reconciliation element intended to meet the short-run budget constraint.

At least four aspects of the pricing regime that remunerates existing capacity are worth questioning: First, where price components are established as a fixed charge, are they set at the right level? Second, is the price structure flexible and adequate? Third, do the special incentives on service quality accomplish their objective of counteracting the perverse effects from SRMC pricing on line availability and, at the same time, of enhancing system reliability as a whole? Lastly, is the overall pricing regime fair to all grid users? So far there are only partial answers to all these questions. Let us examine these concerns.

3.2.6. Are fixed charges set at the right level?

By looking at Transener's current revenue composition, it can be seen that the most important component is the stabilized LL and LR income, which represents 58% of total revenue. The

[14] Given the complete unbundling of the sector, profits for the transmission company increase proportionally to its revenue, as variable costs remain basically unaffected.

[15] This applies whatever the reason for unavailability, except for planned maintenance operations.

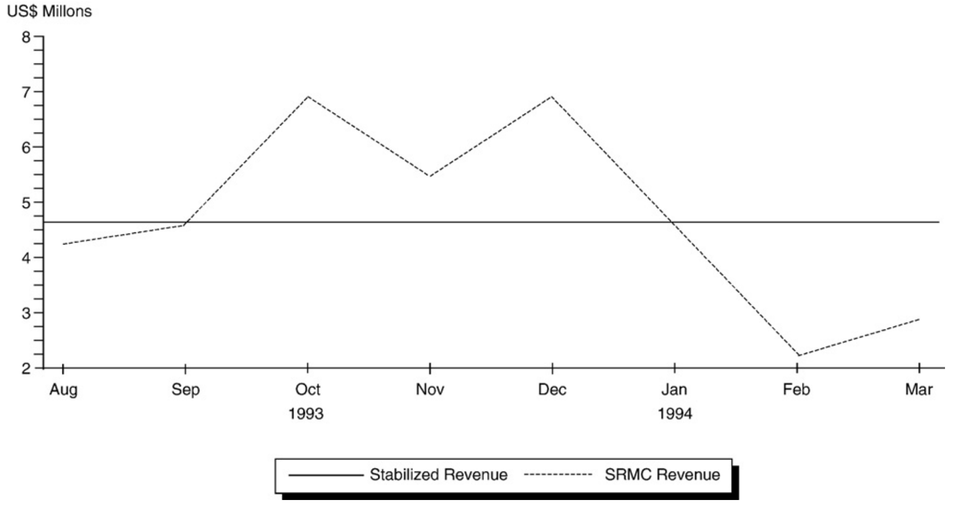

Fig. 1. Volatility of SRMC Transener's revenues.

remainder is composed of outputs whose price levels were set as fixed charges, with access charges accounting for almost 9% of total revenue, and revenue reconciliation charges representing one third.

This composition of revenue, which considers the stabilized LL and LR charges, must be compared to the revenue structure at realized values. For the eight months of operation between August 1993 and March 1994, the sum of realized LL and LR charges represented 55.3% of total Transener revenue, with 36.7% corresponding to the LL component and 16.8% to the LR charge[16]. Although the overall difference between stabilized and realized values for LL and LR charges is not large (<3%), Fig. 1 shows that monthly volatility can be significant.

To determine if average prices of fixed charges were set at the right level, a first approximation would be to compare Transener's current prices with individual average costs for each service. Unfortunately, this information is not available from balance sheets, and thus this accounting approximation to the problem cannot be examined. Nevertheless, even if attributable accounting cost data were available, Transener's optimal cost efficiency levels would have remained unknown, being virtually impossible to determine if prices were correctly cost-based.[17]

The LL and LR components seem to have been set at their purest possible form according to theoretical concepts, but access and revenue reconciliation charges were set in a rather arbitrary way. The last one, indeed, is an important element as short-run marginal costs (SRMC) fall short of average costs due to economies of scale, and also because it represents one third of Transener's revenue. In Argentina, Tabors (1994) reported that the LL component makes up for only 25% of Transener's revenue needs. Tabors' estimate is lower than the realized Transener's revenue from LL, which averaged 36.7% for the first three quarters of operation.

[16] Implicitly, this includes congestion costs and the bonus component on reliability.

[17] A historic cost comparison within the firm would have helped, though this is not feasible as Transener was created from existing assets of three integrated companies (SEGBA, AyE, Hidronor), which did not record separate accounts for their transmission-related activities.

3.2.7. Is the price structure adequate?

3.2.7.1. Limited service differentiation. The structure of transmission prices in Argentina is not independent of the dispatch mechanism. Unlike the England and Wales pool where generators make bids in the spot market, the merit list for electricity supply is based on the regulated fuel costs of generators. The implication for the price structure is that there is no scope for firm transmission demand, as generators do not face the possibility of being denied transmission access, since CAMMESA makes the dispatch decisions.[18] According to Hunt and Shuttleworth (1993), kW charges might make sense to cover the anticipated costs of constraints (including expected compensations when access is denied) in England and Wales. In Argentina, kW charges are only meant to charge customers for the reliability aspect of the network and there are no such elements as compensations for denied access.

3.2.7.2. Limited price differentiation. The lack of flexibility in the context of bilateral contracts between buyers and sellers has been suggested as a shortcoming of the current pricing regime in the Argentine pool[19]. For example, in a bilateral contract one may want the seller to be held responsible for satisfying supply conditions, but he has no control over the behavior of the grid owner. The seller, usually a generator, has no means of fostering the grid owner to increase the reliability of his lines, or of transferring him the penalties for not fulfilling the conditions of the contract in the event of a transmission constraint. In this sense, there is little scope for price differentiation within the context of contractual agreements.

3.2.7.3. Undue charges. A distortion in the current pricing structure can be found by looking at the implicit price increase on the LL and LR elements, due to the special bonus paid when the system is under the status of "loss of load risk". When the loss of load risk situation is created by a supply shortage of generation, the remuneration to the transmission company should remain unaltered. Only when the loss of load risk status is caused by a transmission constraint should the bonuses count on the remuneration to the grid owner.

3.2.8. Do the incentives on service quality work properly?

To counteract the negative signals on line availability that emerge from SRMC pricing, there are penalties and rewards on the performance of each line of the grid. Penalties are charged whenever the line is unavailable, whatever the reason, with the sole exception for outages due to planned maintenance. Rewards are implemented on the basis of outstanding availability performance. What should be the appropriate level of penalties on line availability? How should they be established? Should they be set as a function of duration (or magnitude) of line outages? If so, what kind of function should this be?

To accomplish a target level of availability, the marginal cost imposed by penalties should equal the marginal cost of keeping line availability at such desired regulatory level (point T in Fig. 2). Unfortunately, it is not possible to empirically evaluate this condition, as detailed cost information on the transmission company is not available.

[18] The exception would be a fortuitous event where two generating units with identical fuel costs at the same node, or with identical nodal prices, request access to a common line that is congested at the same time.
[19] This point has been originally brought to my attention by Ernesto Badaracco, and later on by Alberto Devoto.

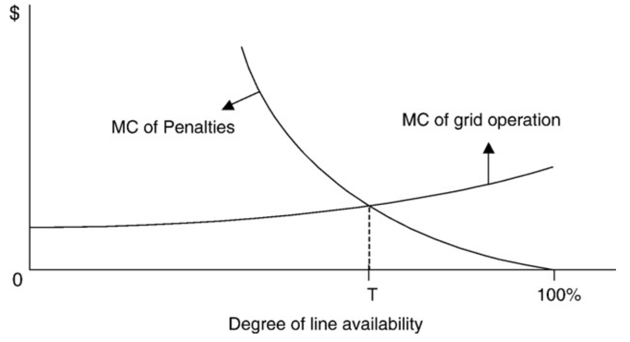

Fig. 2. Equilibrium between marginal cost of penalties and marginal cost of grid operations.

Transener's potential liabilities on penalties have been set proportionally to the value of access and capacity transmission charges. Their level is discriminated by type of line, classified in three categories according to their historical reliability, and is also directly correlated with outage duration and frequency. The chart below (Table 1) illustrates the structure of penalties on line unavailability, according to outage duration and line category.

The chart above shows that, after a grace period of 10 min, there is a strong incentive to finish a repair within the following 290 min, as the marginal penalty is ten times higher than that one for the elapsed time after the fifth hour. What was the technical base for setting 5 h as the binding period of time remains unclear. Notice also that penalty levels are unrelated to the difference between constrained (due to the transmission unavailability) and unconstrained spot prices.

3.2.9. Is the pricing regime fair to all grid users?

The remuneration to existing capacity has at least two elements that may imply cross-subsidies among grid users. First, from the point of view of an individual grid user, the methodology for prorating the complementary charges derived from the differences between estimated and realized LL and LR revenue is not neutral with respect to what the user would have really paid had the stabilization mechanism for Transener's revenue not been introduced. In fact, the overall revenue received by Transener is the same, but the allocation among users is not, as the differences between estimated and realized values are allocated according to the share of the average load demanded or supplied by each user in a particular line, which may not necessarily coincide with

Table 1
Marginal penalty charges for line unavailability

Line category	Repair time		
	<10 min	10 to 300 min	>300 min
A	0	200*CTC	20*CTC
B	0	60*CTC	6*CTC
C	0	20*CTC	2*CTC

Source: Transener's concession contract.
Notes: a. Category A includes the set of lines that can be attributed the cumulative 75% of historic outage costs in the high-voltage transmission grid. Category B includes the set of lines that can be attributed the following 20% of outage costs, and category C involves remaining lines. b. CTC stands for the value of the capacity transmission charge, which was originally set at US$ 48 per hour for each 100 km for 500 kV lines.

what would have resulted from the direct payment of realized values. This prorating practice may create biases to the allocation of charges among users, a risk that Pérez Arriaga (1993) already pointed out as a critical element in the implementation of complementary charges.

Secondly, the regulation envisages that the amount collected from penalties imposed on the transmission owner should be returned to grid users through a reduction on complementary charges. The allocation of the reduction among grid users is done proportionally to the load share for each user of the line, which does not concur with the value of the interrupted transmission service for each user. Therefore, there could be cross-subsidies from users that at the moment of the outage value transmission the less, to those that value it the most at that same time.

4. Investment in new capacity

4.1. The initial mechanism for capacity expansion

Electricity and transmission prices should send the correct signals to investors to allocate investment in transmission efficiently with respect to timing, location, and magnitude. Spot prices of electricity in the Argentine pool are nodal prices that incorporate the short-term spatial argument of the problem. Therefore, the coupling of transmission prices to generation costs does not distort the spatial signals in the short-run. However, transmission prices are not designed to cover long-run average costs or long-run incremental costs. Correspondingly, Transener's license does not oblige it to expand the network.[20]

Transmission expansion, therefore, can be proposed by any qualified party on a case-by-case basis. Either individual or a group of existing users would normally make proposals for new projects. In cases of dedicated lines or when projects are small (under $ 2 million) private parties can arrange directly the expansion with Transener, with other regional transmission companies or with new providers of transmission services.[21] The original legislation contemplates two basic ways of financing the construction of new lines: voluntary agreements among interested parties, and competitive BOM (build, operate and maintain) contracts subject to approval in a public hearing mechanism. In both cases there is the need to require prior approval of the project by the ENRE, which basically performs a formal check on the technical aspects of the projected expansion, and evaluates whether the net present value of total cost of investment, operation and maintenance costs of the system with the project is less than the net present value of operation and maintenance costs of the system without it. This is informally known as the "golden rule".

The voluntary agreement mechanism is straightforward when it involves new lines that connect single users (sellers or buyers) to a particular point of the grid. In these cases, interested parties will tend to finance the construction of the new line, and operate it under the same type of quality regulations and open access principles imposed on Transener.

When projects involve the use of common facilities to several transmission users, the second BOM contract mechanism becomes more appropriate. This mechanism can be seen as a kind of

[20] See Bastos and Abdala (1993).

[21] Private transmission firms other than Transener can undertake new projects. The entrants are called independent transmission companies and can enter into a BOM (build, operate and maintain) contract, subject to the same kind of regulation as Transener. At the high-voltage level, though, Transener remains responsible for network compatibility issues, and for the technical supervision of entrants operating through BOM contract and interconnected with Transener's main grid. The entrant would have to pay Transener a fee equivalent to 3% of total construction costs during the construction time, and a 4% monitoring fee on transmission revenue during the amortization period (2.5% thereafter).

split-savings device, which can be fairly complex, and deserves special attention. The mechanism consists of the following basic steps:

a. A group of parties (generators, distributors, or industrial users) interested in constructing a new line files an application to the ENRE. The application contains the details of a BOM contract, which includes a description of the nature of the project, the annual payment (called canon) needed to finance the venture, and the amortization period.
b. The ENRE evaluates the proposal to check that it meets the "golden rule" requirement as explained above.
c. There is a general methodology that identifies beneficiaries of new project. CAMMESA identifies beneficiaries based on power flows in so-called predetermined "influence areas".[22] Eligible beneficiaries will be liable for paying the canon. A group of eligible beneficiaries would promote the project within a public hearing procedure. Beneficiaries, on the other hand, could also veto projects. To be able to veto filing parties must have at least 30% of the prorated benefits as identified by CAMMESA.
d. If there is no veto, the project can be cleared to the next step, and there the ENRE calls for price competition to the proposed BOM contract (bids compete on the basis of the annual canon) in a public tender process. The ENRE then grants the project to the BOM proposal that offered the lowest canon in the public tender process. If there are no other bids, the project can be granted to the BOM contract proposed in the initial application.

4.2. Assessment of incentives for transmission expansion

The major concerns about the expansion mechanism arise as to who finances the project and how the decision for project approval is taken. The methodology for the identification of beneficiaries has separate steps that end up with the voting decision of users as identified by CAMMESA based on the expected changes in power flows within influence areas.

To determine the allocation of investment costs, CAMMESA first classifies all nodes where there is a change of electricity flows as a consequence of the new transmission project. The region where these quantity changes take place is called the "influence area" of the project. The second step is the grouping of users that are subject to these nodal changes, which are called potential beneficiaries of the project. Next, from the universe of potential beneficiaries, the set of eligible voters for the public hearing is determined. The identification criterion is quite straightforward: beneficiaries are those users whose sum of price and quantity effects is positive, calculated over a projection period of two years. Beneficiaries are liable for financing the new line proposed, and will be responsible for paying the annual canon during the amortization period of the project. The share of these capital costs for each beneficiary is calculated through the ratio of the individual estimated benefits with respect to total estimated benefits.

The whole mechanism for capacity expansion deserves the following critical comments:

a. In the identification of beneficiaries, the mechanism focuses on how users are affected by changes in physical electricity flows in a particular area, instead of focusing on the overall impact of the project on the whole electricity market. The price and quantity effects are restricted to the nodes whose loads are affected by the construction of the new line. However,

[22] See CAMMESA (1994).

the overall impact of the project is felt in the form of price, quantity and quality changes in *all nodes* of the market. In particular, by ignoring the effect on the spot price the mechanism excludes the benefits (through lower tariffs) received by users in importing areas (distributors and end-users), thus discriminating against new and existing generators in exporting areas, which are the ones most affected by the quantity effects as captured by the *influence area*.

b. There are inter-temporal issues that have not been properly resolved, as the horizon used for the identification of beneficiaries (two years) is too short as compared to the useful life of the transmission assets (lifespan of more than thirty years). In the current mechanism this may certainly imply a misrepresentation of eligible voters in the public hearing mechanism. To overcome this difficulty, Pérez Arriaga (1992b) proposed two alternatives, neither of which was implemented in the Argentine market[23]:

i. Granting capacity rights to the original beneficiaries.

ii. Updating the financial charges periodically (i.e., annually).[24]

Perhaps the Argentine regulators never implemented these proposals as the first alternative can conflict with the open access principle, as initial beneficiaries could exercise monopoly power over new entrants in the future. The second alternative, on the other hand, is more in line with what the ENRE and CAMMESA would have liked to put into practice, although there are complexities in its implementation. The updating of the allocation of capital costs (canon) can be a cumbersome and costly regulatory exercise since changes in existing capacity and revisions of several variables used in the projection exercise done by CAMMESA need to be included in the update. This, in turn, creates financial uncertainty to beneficiaries and thus may impair the investment decision. Finally, for the investment decision to take place, a BOM contract needs assurance that those who are liable will be so at least for the entire amortization period of the project. If such liability is to be transferred to others due to a regulatory decision, there is a potential for collection risks, unless the transfer of such liability is strongly enforced on future grid users identified as beneficiaries at later stages.

c. Participants whose net effect is negative should in principle be excluded from the analysis, as it is currently established in the existing mechanism. This is a natural consequence of the distributional effects from trade: consumers in the exporting area and producers in the importing area tend to lose. However, as stated in Pérez Arriaga (1992b), the existence of previous rights of legal nature may imply the need for some kind of compensation for those identified as losers.

d. The regulation is unclear as to how to treat proposals that are presented simultaneously. For example, if there is more than one transmission project that needs to be evaluated at the same time, should projections used for the evaluation of each proposal be made independently of the realization of the others, or should they be made contingent to them? If all projects are evaluated together, what is the scope for strategic filing behavior on the part of interested parties?

[23] The proposal by Pérez Arriaga resembles that of Grant Read from the University of Canterbury, although it has been developed independently.

[24] This update would require a recalculation of the allocation of the canon charges among existing and new beneficiaries. To avoid uncertainty, the Pérez Arriaga proposes the implementation of medium and long-term transmission price insurance contracts, similar to the contracts for differences in the England and Wales pool.

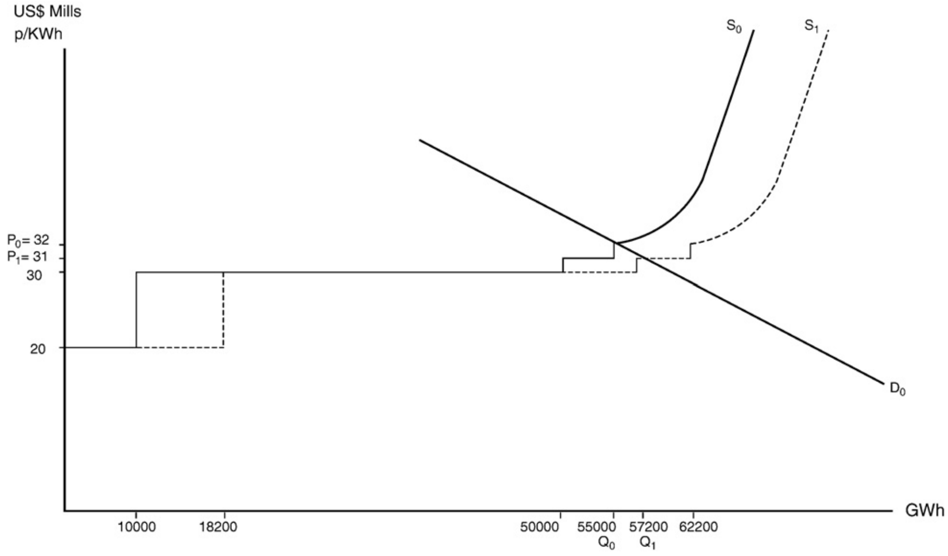

Fig. 3. Impact of new transmission project in the wholesale electricity market.

4.3. Alternative scheme on the investment cost allocation rule

In this subsection I develop an alternative scheme that attempts to correct some of the shortcomings detected above, yet still follows the underlying basic principles set by the Argentine regulation. Without claiming it to be an exhaustive and detailed proposal, I present some guidelines for such a scheme, based exclusively in a change in the rule for the identification of beneficiaries. The optimal rule for investment is kept the same, but the scope for who the potential beneficiaries are is enlarged, as end-users are added, and the entire electricity market (as opposed to the influence areas) is looked into.

The proposal is motivated by the need to include end-users as part of the identification of beneficiaries, since I believe end-users are ultimately responsible for locating their electricity demand in a site that requires energy from remote locations, which indeed triggers the demand for expanding generation and transmission capacity.

The scheme identifies beneficiaries in a two-stage process where four broad categories of potential beneficiaries are considered: end-users – which buy from distributors, – industrial users – which buy from the wholesale market, – distributors and generators. In the first stage, the scheme focuses on the wholesale electricity market to separate the welfare effect on the demand side from that of the supply side. Within the supply side, it is possible to estimate generators' shares of benefits at this market level. In the second stage, there is the need to draw on the retail level to separate the shares of benefits among end-users, distributors and industrial users.

We start with an existing equilibrium point in the wholesale market, which I call state 0 at a point where supply (S_0) equals demand (D_0). This is illustrated in Fig. 3 and Table 2 We then compare this initial state of equilibrium with a state that shows a supply increase derived from the new transmission project (state 1) that brings in additional electricity supply flows. The purpose is to separate and quantify, using traditional welfare analysis, the changes associated to consumer and producer surplus. In the supply side, the example shows that in state 0 there were three existing generators (A, B, and C) with different technologies. In state 1 there is an entrant generator that, through the use of the new transmission project can produce electricity at a less expensive cost than existing generator C. To make the analysis richer, in state 1 (identified at equilibrium point P_1, Q_1) there are also changes in the quantity supplied by generators A and B. The overall effect experienced by generators can be calculated as the difference in their total operating income between the two states, or

$$\Delta G^i = q_1^i\left(P_1 - C_1^i\right) - q_0^i\left(P_0 - C_0^i\right) \quad \text{for } i = \text{A, B, C.} \tag{6}$$

The positive change in consumer surplus should be attributed to all beneficiaries of the demand side, and as a first-order approximation[25] it can be calculated as

$$\Delta \text{CS} = (P_0 - P_1)Q_0 + ((P_0 - P_1)(Q_1 - Q_0))/2 \tag{7}$$

Table 2 shows, for illustration purposes, a numerical example of these calculations of welfare effects. At the wholesale level I can identify the beneficiaries' share of capital costs that correspond to each generator (10.4% for A and 48.4% for the entrant in this example) and to demand beneficiaries as a whole (41.8).[26]

To allocate the share of consumer surplus among industrial users, end-users, and distributors within the demand side, the scheme proposes to calculate the relative welfare gains of each actor accrued at the retail level of the market. Once again, for illustration simplicity, it is assumed that distributors and industrial users buy at average wholesale market prices (P_0 and P_1), and that distributors sell to end-users at wholesale prices plus a fixed value-added term. Quantities sold by distributors are the quantities bought in the wholesale market minus the electricity losses in distribution.

The payoff function of end-users and industrial users is similar to Eq. (7), except for the quantity purchased in the case of industrial users and quantity and prices for end-users. For distributors, the payoff function is:

$$\Delta D = \left[Q_1^r P_1^r - \left(Q_1^r + L_1^r\right)P_1^w\right] - \left[Q_0^r P_0^r - \left(Q_0^r + L_0^r\right)P_0^w\right] \tag{8}$$

where the superscript w stands for wholesale, and r for retail, and L^r refers to losses in distribution.

Notice that the overall welfare gain at the retail level should not necessarily coalesce with the overall consumer surplus at the wholesale level, as there is value-added in between. Nevertheless, the distribution of welfare gains at the retail level (70%, 10% and 20% in the numerical example) can be used as weights to determine the allocation of beneficiaries' share over the total amount estimated from the wholesale level. The final distribution of capital costs among beneficiaries from both supply and demand side can thus be calculated as shown in the last table of Table 2.

The limitation of the proposal is that the scheme is rooted in a static comparative analysis, without addressing some of the consequences of identifying beneficiaries in a dynamic scenario

[25] There is an implicit assumption of demand linearity. Although the real demand curves are barely linear, for the purposes of calculating changes in consumer surplus caused by a relatively small change in supply, the linearity assumption appears to be a valid approximation.

[26] For simplicity, the example works with an aggregate average market price, without discriminating among different types of effective remuneration paid or received by each actor (active power reserves, nodal factors, contractual prices, adaptation factors, etc), though these elements can be easily incorporated into the scheme without altering its basic structure.

Table 2
Capital cost allocation of a new transmission project

Wholesale level					
Without project			With project		
P_0 (mills/KWh)	32		P_1 (mills/KWh)	31	
Q_0 (GWh)	55,000		Q_1 (GWh)	57,200	
Generators	GWh	Fuel cost	Generators	GWh	Fuel cost
q_0^a	10,000	20	q_1^a	12,200	20
q_0^b	40,000	30	q_1^b	39,000	30
q_0^c	5000	31	q_1^c	0	31
q_0^{new}	0	–	q_1^{new}	6000	20
Q_0	55,000		Q_1	57,200	
	Quantity effect (US$ millions)	Price effect (US$ millions)	Total effect (US$ millions)	Beneficiaries (US$ millions)	Beneficiaries shares
Consumer surplus			56.1	56.1	41.2%
Producer surplus					
Generator A	26.4	−12.2	14.2	14.2	10.4%
Generator B	−2.0	−39.0	−41.0	0	0.0%
Generator C	−5.0	0	−5.0	0	0.0%
Entrant	72.0	−6.0	66.0	66.0	48.4%
Net welfare gain	91.4	−57.2	90.3	136.3	100.0%

Retail level					
Without project			With project		
Wholesale price	P_0^w	32	P_1^w		31
End-user price	P_0^r	40	P_1^r		39
Consumption		GWh			GWh
End-users		42,000	End-users		43,680
Industrial users		6000	Industrial Users		6240
Losses in dist,		7000	Losses in dist,		7280
Total		55,000	Total		57,200
Demand side allocation		Total effect (US$ millions)	Beneficiaries (US$ millions)	Demand side shares	Beneficiaries shares
End-users		41.6	41.6	70.0%	28.8%
Industrial users		5.88	5.88	10.0%	4.1%
Losses in dist,		11.76	11.76	20.0%	8.2%
Total		58.8	58.8	100.0%	41.2%

Total allocation of capital costs	
Generator A	10.4%
Generator B	0.0%
Generator C	0.0%
Entrant generator	48.4%
End-users	28.8%
Industrial users	4.1%
Distributors	8.2%

Source: Prepared by the author.

in which there are new entrants in both demand and supply side. The extension to a dynamic framework, however, should not alter the main conceptual results found for the allocation of capital costs, though the mechanics for the exact calculation of shares would need to be refined.

This scheme shows that when one focusing on the broader concept of welfare effects over the whole electricity market, as opposed to the narrower concept of physical flows under influence areas, the extent of potential beneficiaries is amplified to include end-users, who are the ones demanding transmission capacity to buy energy from remote locations. In a two-stage process (wholesale and retail levels), the shares of capital costs to finance the new investment can thus be allocated among end-users, distributors, generators, and industrial users, spreading the burden of transmission investment costs among a larger (and likely fairer) universe of beneficiaries. This, in turn, should result in a reduction of the risks of underinvestment, as compared to the existing rule.

5. Conclusions

The regulation of a private firm that operates and controls a national electricity grid is a relatively new and challenging subject. In this paper I describe and analyze critically the main features of the Argentine system, where electricity reform has introduced a decentralized system with the main national grid operated by a company (Transener) that was separated from both generation and distribution activities, and where new entry is allowed for new investment projects.

Through the acquisition of concession rights, Transener obtained monopoly rights for the operation of the existing grid, though in return it has to fulfill certain contractual obligations. Transener cannot sell or buy energy from the marketplace, is required to provide open transmission access to all parties when capacity is available, and is subject to high-powered incentive regulation on price and quality. Transener, however, is not subject to the obligation of network expansion. Rather, to finance investment in new lines a separate mechanism has been devised, which is mainly based on competitive BOM contracts (build, operate and maintain) subject to users' proposal and approval in a public hearing procedure.

5.1. Incentives and pricing of existing transmission capacity

The following conclusions about the existing regulatory regime on existing transmission capacity are worth mentioning:

a. Transener's pricing scheme remunerates existing capacity based on line losses and reliability, congestion costs (implicitly), access charges and revenue reconciliation or complementary charges.
b. To make up for the perverse effects derived from short-run marginal cost (SRMC) pricing, (the higher the losses and the lower the reliability of the line, the higher the grid company revenue) regulation has sensibly been complemented with penalties and bonuses on line availability. Penalty values are set proportionally to access and complementary charges instead of being related to the difference between constrained and unconstrained spot electricity prices. A more thorough evaluation on the properties of quality incentives is called for to learn if the marginal cost imposed by penalties equals the marginal cost of keeping line availability at the desired regulatory level.
c. There is no available basis for comparison to state whether average regulated prices are set at the right level or not. To meet the short-run budget constraint, though, there is a revenue reconciliation charge that accounts for one third of Transener's revenue. The price structure, on

the other hand, shows limited scope for service differentiation and for flexible contractual agreements.

d. The open access principle and the cost-based dispatch rules avoid uneconomic discrimination in event of on rationing capacity. However, it is thought that the latter curtails the scope for differentiation of transmission services.
e. The pricing regime may not be equitable, as the way in which complementary charges are prorated results in implicit cross-subsidies among users. The magnitudes of these subsidies are yet unknown, but are expected to be small.

5.2. Incentives for transmission expansion

For investment in new capacity, the original mechanism put in place in Argentina has the potential to misallocate the costs of financing new lines, as it implicitly ignores basic welfare effects, especially by failing to identify the demand side as a beneficiary of new projects. By focusing solely on the network users that experience changes in physical electricity flows, the mechanism fails to measure benefits derived from price, quantity and quality effects felt all over the market.

There are also other shortcomings such as an inter-temporal dimension not properly resolved, as the time horizon used in the analysis is too short. All these issues, in combination with the ad-hoc public hearing procedure adopted, could result in deviations from the optimal investment path in transmission.

I have therefore developed a proposal with general guidelines for an alternative investment rule, which still relies on grid users' initiatives and approval, but which focuses on an allocation of investment costs based on traditional welfare analysis. By focusing on the welfare effects over the whole electricity market, the proposal broadens the scope for identification of potential beneficiaries, by including end-users in the demand side. In a two-stage process (wholesale and retail levels), the allocation of investment costs can thus be spread over a larger (and likely fairer) universe among end-users, distributors, generators, and industrial users.

The alternative scheme does not attempt to be an exhaustive and detailed proposal. In particular, the proposal is based on a static analysis, without an attempt to solve the complexities of dynamic cost allocation. The extension to a dynamic framework, however, should not alter the main conceptual results found for an alternative rule of investment cost allocation.

5.2.1. Postscript 2007

In ex-post reflection, thirteen years after writing my original article, I find that any critical review of Argentina's regulatory regime in transmission has to take into account that qualified observers will agree that the electricity sector reform of the early 1990s was a notable success. Indeed, there was widespread entry of private investment in all segments of the market (generation, transmission, distribution and marketing). Total installed capacity increased from 14,061 MW in 1992 to 23,189 MW in 2001 (an increase of almost 65% for the period). Transmission has equally shown explosive growth: medium- and high-voltage lines increased 42% in length in 1991–97. Wholesale electricity prices more than halved, retail prices have also fallen, and overall quality improved substantially during the first decade since the 1992 reform.

I also find that the cross-subsidies implicit in the pricing system for the remuneration of existing capacity turned not to be too important in magnitude. Neither does there seem to have been any systematic bias in favor or against any particular group of grid users, or any noticeable impact on reliability and quality of the network. In addition, I find the penalties for lack of line availability worked very well in preventing transmission failures.

Regarding the cost allocation rules for major transmission investments, there were some conflicts involving major projects as well as congestion related to transmission restrictions. In large projects involving externalities and benefits to an extended set of grid users, reaching voluntary agreements through multilateral private contracts would have been virtually impossible. Rather some sort of governance mechanism needs to be put in place for projects involving investment decisions affecting multiple parties. In Argentina, at the federal level, the public hearing mechanism played this governance role.

The public hearing mechanism has proven to be sensitive to the ex-ante allocation of investment costs, as well as the administrative allowances of congestion rents, and to free riding behavior. These ad-hoc rules for transmission expansion through the public hearing procedure has produced too little investment in the views of some observers, whereas others think it might have just been the right mechanism to avoid overinvestment. Nonetheless, at a theoretical level the investment allocation rule for large projects could still be improved, in a direction that would allow a better representation of grid users' preferences.

Overall, the rules for transmission operation and investment in Argentina do not seem to have substantially deterred private investment, in particular if one observes that a significant portion of new transmission contracts have involved voluntary agreements by the parties. The Argentine experience for the 1992–2001 period provides a fine example of how to improve on the conventional complexities of regulating transmission lines in competitive electricity markets.

The focus of the regulatory discussion in Argentina has shifted dramatically since 2002. The issues under discussion are no longer centered on the "optimality" of the rules of the games for private transmission investment, but rather on the extent of government intervention on investment decisions and, ultimately, how to avoid government discretional interference and opportunistic behavior towards private investment. I discuss this subject on my second paper in this Symposium.

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