Paper accepted for presentation at 2009 IEEE Bucharest Power Tech Conference, June 28th - July 2nd, Bucharest, Romania

Risk Allocation for Efficient and Timely Transmission Investment under Markets with High Demand Growth

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***Abstract*—Under the need for anticipatory efficient investment in transmission, several problems arise at the regulation and incentives level; economies of scale justify carrying out larger initial transmission investments that existing generation and demand may be not willing to pay. This problem is increased with high demand growth where anticipatory investment is crucial for converging to an efficient electric system. Without anticipatory investment, the net number of lines in the long term may be duplicated/triplicated and/or the cost of reinforcing may sharply increase as lines were not initially built to be (easily) upgraded. This cost increase, assumed by generators in the case of additional lines, can ultimately create a barrier to entry for new agents and therefore constrains competition in the market while also impacting end user tariffs. In this paper a formal methodology is proposed to allocate the extra funds needed to build upgradeable additional lines. This is applied to a particular case in the Chilean electricity market.**

***Index Terms*—Transmission planning, transmission investment, regulation, additional lines, anticipatory investment, power system economics**

I. Introduction

UNTIL the beginning of the 1980's, worldwide the electricity market vertically integrated its whole supply chain into a large company (State or privately owned) in each electric system. Then, some countries such as Chile and the UK led a restructuring process to liberate the market. The separation of the market into generation, transmission and distribution segments was the main change carried out by this restructuring process. Since each aforementioned segment is different in nature, diverse market philosophies were defined to command each of them as follows:

- Competition was established in the generation segment
- Transmission and distribution segments were defined as monopolies

Regarding the monopoly nature of the transmission business, it is needed to define tariff, expansion/investment and access policies, among others, in order to correctly give an incentive to investors and so obtain an efficient (least-cost) interconnected system.

According to marginal theory, if Locational Marginal Prices (LMPs) work, then transmission investment is ensured by a company that: (i) takes the price differentials and (ii) makes equal its investment cost to the revenue obtained from the aforementioned differentials [1]. However, due to economies of scale and market failures, transmission investment may not be properly ensured in deregulated markets, and often high levels of congestion and non-timely investment are observed [2].

In this framework, this paper proposes a regulatory scheme where timely optimum transmission investment is facilitated when a market presents difficulties to efficiently allocate capacity across the system.

II. Contexts of the Problem

A. The source

An emblematic hydro project in Aysen, Chile, called HydroAysen, is leaving room for doubt whether the current regulation can deliver optimum transmission investment regarding additional lines. This type of assets is usually built according to bilateral negotiation between the interested generation company and the transmission entity due to the private nature of this business.

B. Formalizing and generalizing the problem

The general problem is described as follows:

1) Consider a new generator (generator 1[1]) requiring interconnection to the main transmission system from a distant remote area[2]
2) The transmission investment needed to interconnect this new generator to the main system has a cost of C_1 [$] and a capacity of P_1 [MW]
3) However, more potential generation (generator 2[3]) may enter the market due to the high availability of the resource in the new area and the high demand growth of the market. If so, the best (least-cost) alternative for investing would be installing, initially, a flexible interconnector with a cost of C_2 [$] ($C_2 > C_1$) and a capacity of P_1 [MW], which can be easily upgraded up to P_2 [MW] in the future[4].
4) As expected, the flexible technology is initially more expensive, but if the probability of installing the future generation is high enough, then the least-cost

[1] HydroAysen is a project with a capacity equal to ~3 GW

[2] A 2,000 km HVDC link is needed to interconnect this area to the main transmission system

[3] Resources in the Aysen (unexplored) area are equal to ~10 GW

[4] P_2 is the needed capacity to transmit the power from generator 1 and 2 to the main system

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978-1-4244-2235-7/09/$25.00 ©2009 IEEE

solution would be installing the flexible/upgradeable link.

Although, the least-cost solution is clear enough when computing a Cost-Benefit Analysis such as the explained in [3], a key question is whether the current regulation adequately incentivises Transmission Companies (Transcos) to invest in an objective, timely and efficient fashion. For example, under the Chilean regulation, where all the transmission cost of injecting lines is passed through to generators, several problems arise when the extra cost for flexibility is allocated, such as:

- If (i) the most expensive technology is considered in order to have a flexible interconnector (link) for transmitting future generation and (ii) the G_1 is forcedly charged with its entire cost; then this generation project may not yield and so it would not be built
- If the cheapest technology is considered in order to incentivise the entrance of the current generation project, then:
  - future generation projects may not enter the market due to the high costs for building a new link
  - future generation projects may enter the market by duplicating lines and so leading to a more expensive system

So, the main concerns arisen are that the fact of not investing anticipatorily may: (i) lead to an inefficient transmission system (more expensive), and/or (ii) block the entrance of timely generation. Figure 1 illustrates the cost differences between anticipatory/coordinated and independent investments.

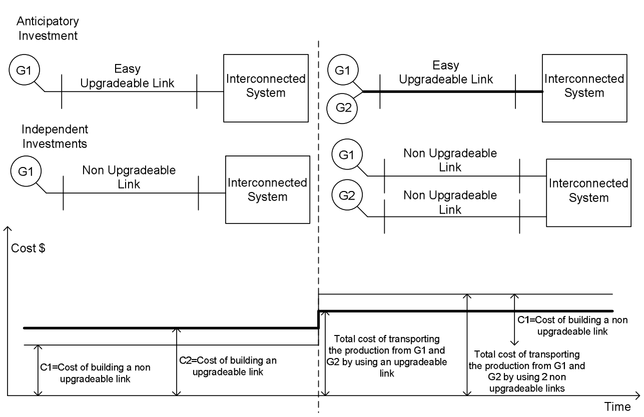

Fig. 1. Diagram of the 2 most probable situations for transmission investment in Aysen

It is straightforward to observe that these concerns becomes more important in the presence of significant economies of scale (expensive fixed costs), for example, the ones associated to HVDC links. For this particular case, the main fixed costs that may justify an anticipatory investment are the HVDC converters, land rights across a long distance and building costs among others.

C. *Understanding the particularities*

According to international benchmarks, the main part of the investment cost for a DC transmission line is the HVDC converter substations as shown below [4].

Costs for DC power transmission:

- 27% cable and cable installation
- 20% site/regulatory/environmental
- 53% HVDC converters/building/commissioning

Regarding cables and their installation, it is straightforward to see that transmission cost savings arise when an upgradeable interconnector is considered because several cables and their infrastructures can be concentrated in a bigger transmission line. This fact implies that part of the fixed cost can be avoided. Since DC power lines need small amounts of infrastructure to transmit high levels of power flows (less infrastructure than AC power lines), to build more than one link to transmit small power flows (less than 1,000 MW) may highly increase the net transmission cost (see Figure 2).

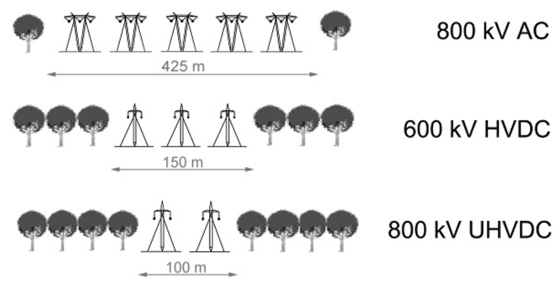

Fig. 2. Pilons needed to transmit 10 GW [5]

In addition, savings with regard to the site, regulatory and environmental costs also arise when considering the construction of an upgradeable link. When different agents independently negotiate their own land rights, and face their own construction and management process, the associated costs increase. For the land rights, complex and extensive negotiations take place with the intention of defining the optimum and possible line path. Therefore, a combined negotiation would drop the cost and the difficulties of the process. What is more, in the Chilean case the line should pass through a protected national park (Parque Pumalin) and so building a second interconnector would face heated opposition. As a result, building independent lines can become a strong barrier to entry for future participants.

As shown in Figure 3, the HVDC converter substations exhibit high levels of economies of scale. Thus, joint use of these electric devices can sharply drop the cost of the system and so allows the market to operate more efficiently.

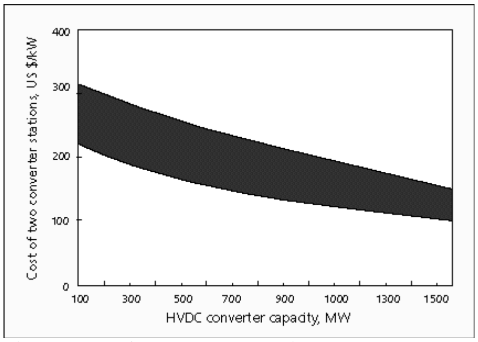

Fig. 3. Cost of two converter stations [6]

It is important to mention that a HVDC transmission project can be built in stages. This is so as to meet the need for a gradual increase of transferred power. In many applications HVDC is chosen for a larger power transfer capability on a long-term basis. The transfer might be low in the initial stage and higher after a certain period. The most common staging for DC transmissions is to first build a monopole and later a bipole. A new bipole can be added later or the converter stations can be upgraded in current and/or voltage by adding converters in parallel or series [6].

Finally, the fact of charging the entire cost of the new interconnector to generation puts a barrier to the efficient development of the system. The question is now how regulation should evolve in order to give an incentive for Transcos to undertake optimum anticipatory investments.

III. Theoretical Framework

As explained in the literature [1], under perfect conditions, optimum transmission investment is recovered by taking the nodal price differential across the interconnected system. In this situation, existing generation and demand are equally benefited in the sense that both generation and distribution can cater for the entire transmission investment when taking the price differential. However, under real market conditions, the need for anticipatory investment to efficiently supply future power flow increase may be not covered for the willingness to pay of existing generation and demand.

The transmission system can be understood in several ways. In this paper, an additional line is seen as a public asset, where the users such as the generators directly interconnected to the link (at the production side) and demand receive its benefits by transporting power from one point to another[5].

In the Chilean regulation, although the main transmission system is paid by generation and demand at the same time according to an 80/20 ratio respectively, additional lines are only paid by generation or demand depending on the nature of their flows (injecting or withdrawing power to/from the main system). Thus, in the case of an additional line for injecting power, this is completely paid by the generators who use the line, even when demand also receives its benefits. So, as in many other examples where public assets are regulated, an additional line for generation can be also paid by demand as it is also benefited. What is more, there are cases in which demand can be potentially much more benefited from an investment in an injecting additional line than the existing/first generator who uses this transmission asset. In these cases, demand arises as the potential responsible for the payments of the aforementioned asset.

IV. Proposal and Applications

A. Rationale and Proposal

In the problem presented in Section 2, the market solution may be installing the link with a cost equal to C_1 as:

a. Charging the new generator G_1 with C_2 is not possible because its opportunity cost is lower, i.e., the new generator G_1 would build its own additional link and interconnect its plant to the rest of the system if it would be charged with C_2

b. The transmission company may not take any cost which is not ensured due to risk aversion, even the extra cost (C_2-C_1), especially when considering that the main business of the transmission company is to provide its service under a price cap scheme[6].

Thus, unless the Transco makes an anticipatory investment which is very unlikely under the current scheme, it is not possible to ensure the convergence to the least-cost electric system.

By applying the concepts illustrated in Section III, the least-cost solution can be centrally implemented where generator 1 pays C_1 and the extra cost is paid by demand if distribution is interested in doing so. As an alternative, decentralised market arrangements can be implemented in order to give an incentive to Transcos to anticipate investment. For example, in the UK some proposal toward these directions has been done in order to connect large amount of future wind generation as follows [7, 8]:

- For the proportion of the delivered capacity that there is full user commitment at the time of Transcos initiating investment, then normal price control provisions would apply
- For the remaining proportion of the delivered capacity not yet utilized some minimum level of funding is provided

Under this framework, demand could provide the extra amount of funds in order to supply a minimum level of funding to incentivise future investment. For doing so, it is needed to assess whether demand would receive benefits from providing this extra cost.

<u>Formal proposal:</u>

As explained in Section III, the key aspect is checking who will obtain the benefits from having a larger link.

Firstly, the new generator G_1 will not obtain any benefit from installing a larger link. In contrast, it will facilitate competition and so it may be ultimately negatively affected.

Secondly, the transmission company cannot be charged with an extra cost that neither generation nor demand is paying. This is particularly important in frameworks where price cap regulation is applied and costs are passed to users.

Finally, it is straightforward to see that, among the existing participants, demand is the only agent that will obtain

[5] In the production side of the line, there is no demand (or it is negligible) and, on the other side, generation is not receiving any benefit by the power transfer through the line

[6] Under a classical price cap scheme, there are no incentives to anticipatorily invest

potential benefits when future generation arrives by using the already installed upgradeable link. For the sake of simplicity, when assuming only two static time windows (Δt_1 and Δt_2), this potential or expected benefit can be quantified by computing:

$$E\{Benefit\} = \text{expected demand payments with the non upgradeable link} \quad - \text{expected demand payments with the upgradeable link} \tag{1}$$

$$\begin{aligned} E\{Benefit\} = {} & [\pi_{G1} \times Dem_1 \times \Delta t_1 + \pi_{G1} \times Dem_2 \times \Delta t_2 \times (1 - \Pr_{without\_link}) \\ & + \pi_{G1G2} \times Dem_2 \times \Delta t_2 \times \Pr_{without\_link}] \\ & - [\pi_{G1} \times Dem_1 \times \Delta t_1 + \pi_{G1} \times Dem_2 \times \Delta t_2 \times (1 - \Pr_{with\_link}) \\ & + \pi_{G1G2} \times Dem_2 \times \Delta t_2 \times \Pr_{with\_link}] \end{aligned} \tag{2}$$

$$E\{Benefit\} = (\pi_{G1} - \pi_{G1G2}) \times (\Pr_{with\_link} - \Pr_{without\_link}) \times Dem_2 \times \Delta t_2 \tag{3}$$

Where,

E{Benefit} : expected cost saving (benefit) of demand when an upgradeable link is built instead of a non upgradeable one [$]

π_{G1} : market spot price after commissioning of G_1 and before commissioning of G_2 [$/MWh]

π_{G1G2} : market spot price after commissioning of G_2 [$/MWh]

Dem_1 : average demand during Δt_1 [MW]

Dem_2 : average demand during Δt_2 [MW]

$Pr_{without\_link}$: probability of generator 2's entrance when a non upgradeable link is installed [p.u.]

Pr_{with_link} : probability of generator 2's entrance when an upgradeable link is installed [p.u.]

In simple words;

$$\begin{aligned} E\{Benefit\} = {} & [\text{Probability increase of generator 2's entrance} \\ & \text{when building the upgradeable link}] \\ & \times \Delta[\text{Energy price decrease when entering generator 2}] \\ & \times Dem_2 \times \Delta t_2 \end{aligned} \tag{4}$$

Whilst E{Benefits} ≥ (C_2 – C_1), demand will be willing to pay the extra cost of building a larger link and therefore it can be justifiably charged. However, this methodology is not robust and so problems to apply this proposal arise if E{Benefits} < (C_2 – C_1) even when a CBA suggests that the installation of the larger link is optimum for a given set of potential future scenarios. In the latter, neither existing generation nor distribution are willing to pay the extra cost of building an upgradeable link which leads to the efficient system in the long-term, so allocating the extra funds to build the larger link becomes, once more, a dilemma.

To sum up, additional lines should be centrally planned in critical areas such as Aysen by using an open access policy for future generation. Existing projects can remain paying what they already pay when considering the current scheme (the cost of building a fitted line for them) and demand should pay the cost differential between building a flexible and inflexible link if E{Benefits} ≥ (C2 – C1). Finally, this extra cost or cost differential can be allocated among different consumer by using distribution factors.

B. Application

Consider that in the case of HydroAysen, the transmission investment is estimated equal to C_1 = 2.5 bUS$ for the inflexible link and C_2 = 3 bUS$ for the upgradeable link (same capacities). Thus, 0.5 bUS$ is the differential between installing an 800 kV HVDC link initially operated at 3 GW – 600 kV, which can be upgraded by adding converters in the near future and an inflexible transmission project of 3 GW – 600 kV . In addition, the building of an inflexible interconnector eliminates the possibility of having more generation investment in the zone (at least in the short/mid term). Also, the entrance of another generator would drop energy prices off by 2 US$/MWh since 2018 (10 more years) and there is a probability of 30% that new generation enter the market due to the flexibility of the link.

With this information, the net expected benefit of demand is equal to (r = 10% and demand growth g = 6.5%):

$$E\{Benefit\} = \sum_{t=10}^{\infty} \frac{2 \text{ US\$/MWh} \times 0.3 \times 12{,}000 \text{ MW} \times 0.744 \times 8{,}760 \text{ h}}{(1+r)^t \times (1+g)^{-(t-10)}} = 1.1 \text{ bUS\$} \tag{5}$$

Then, 1.1 > 0.5 and therefore a flexible link should be centrally planned when charging demand with the cost differential between the flexible and the inflexible investment.

V. Conclusions

This paper proposes a scheme that manages risk in order to facilitate efficient and timely transmission capacity, especially in markets with high demand growth where the probability of having increasing power flows in the transmission system is high.

Although when this proposal is not robust, this attempts to resolve the dilemma of risk allocation under the need for anticipatory investment when also minimising demand payments (generation pays its entire opportunity cost) and conserving a profitable transmission charge for generation (it does not pay more than its opportunity cost of building a fitted line). This scheme provides a minimum level of funding to correctly incentivise anticipatory investment to transmission companies. This is of special interest for regulators.

It is important to mention that even a decentralised framework based on negotiation between generation and distribution can be established for situations where E{Benefits} ≥ (C_2 – C_1) and the sum of the willingness to pay of both generation and demand is strictly higher than the cost C_2; C1 + E{Benefits} > C_2. Incentives for distribution to do so must be designed.

The methodology has been developed in order to give a technical/political solution to the particular problem of anticipatory investment and risk allocation for additional lines. Nevertheless, this proposal can be extended in order to solve other problems regarding the entire transmission system when anticipatory investment is needed.

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VII. Biographies

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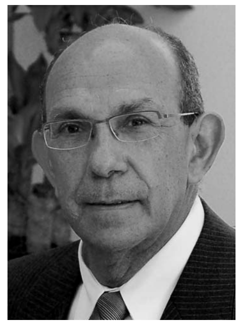

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