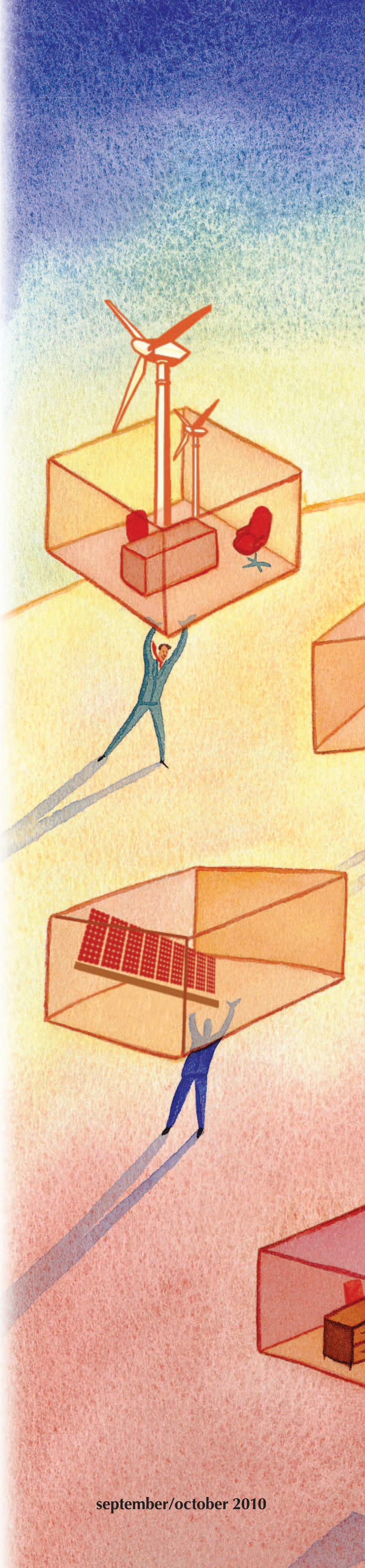
Making Room for the Boom

New Regulatory Avenues and Network Infrastructure Changes for Accommodating Renewables in the United Kingdom, Brazil, and Chile



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ELECTRICITY SYSTEMS WORLDWIDE FACE CHALLENGES OF unprecedented proportions. In response to the climate change crisis, the governments of a number of countries are already committed to the support of renewable and other low-carbon generation technologies for the next ten years. Over the medium and long term, it is expected that the electricity sector in some jurisdictions will be almost entirely decarbonized and that there will be significantly increased levels of electricity production and demand, driven by the incorporation of the heating and transport sectors into the electric grid.

In this context, the electricity network will play a key role in facilitating the cost-effective integration of significant amounts of low-carbon technologies. In fact, many policy makers have already recognized the need for significant investment in network infrastructure. For example, Barack Obama, the current U.S. president, declared in October 2008: "One of…the most important infrastructure projects that we need is a whole new electricity grid. Because if we are going to be serious about renewable energy, I want to be able to get wind power from North Dakota to population centers like Chicago."

Following this path, companies in North America have already identified approximately US$37 billion in transmission investment needed by 2020 to facilitate integration of renewables. For similar reasons, other countries such as the United Kingdom and Spain are currently considering transmission investment plans

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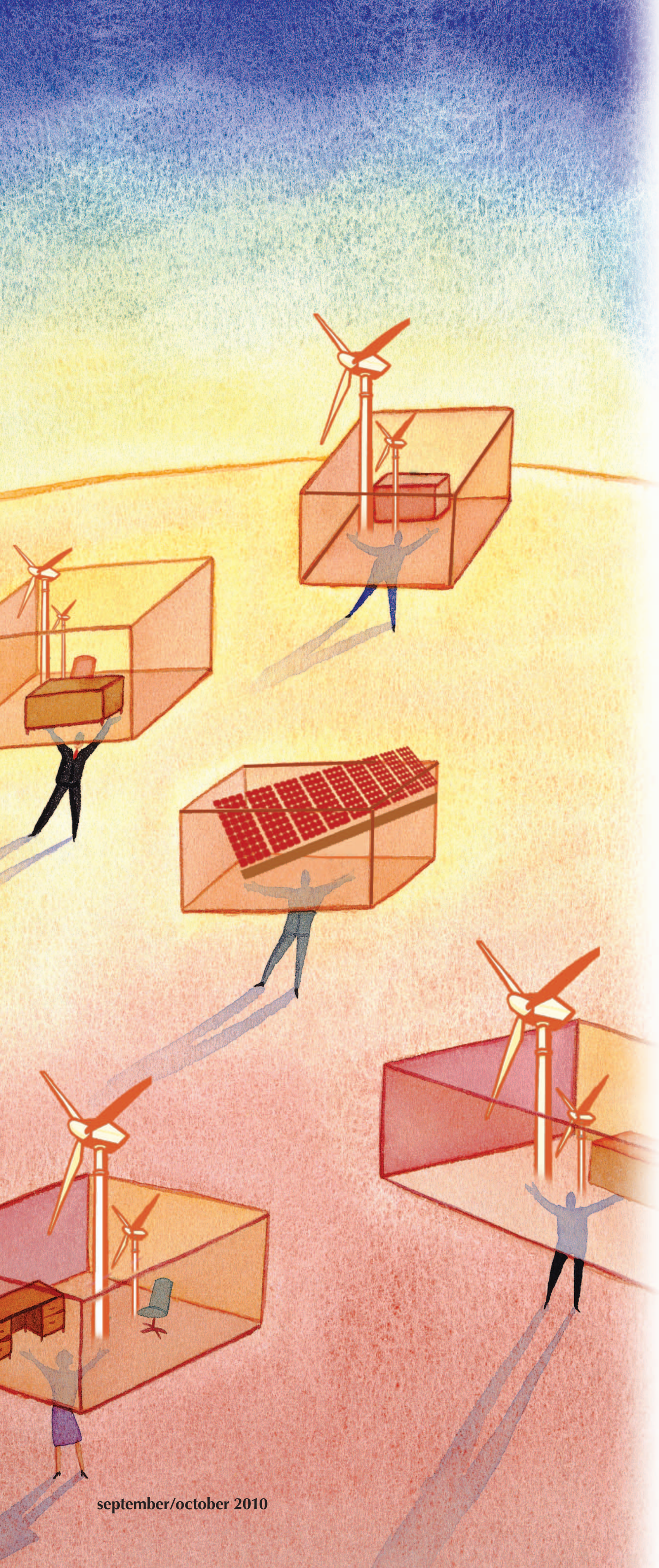

By Rodrigo Moreno, Goran Strbac, Fernando Porrua, Sebastian Mocarquer, and Bernardo Bezerra

of about £15 billion (2010–2020) and €4 billion (2010–2014), respectively. The European Commission has recently (2010) allocated €910 million for 12 electricity interconnection projects as part of its European Economic Recovery Plan.

The need to facilitate the connection and integration of renewables will also require fundamental changes in the technical, commercial, and regulatory arrangements associated with electricity networks, however. In this framework, we present three study cases: the United Kingdom, focusing on transmission, and Brazil and Chile, covering both transmission and distribution networks. These experiences illustrate a diverse array of network impacts due to the increasing amount of renewables, including network design, access, pricing, and regulation.

The United Kingdom

A Major Reinforcement of the Transmission Network

In common with most industrialized countries, U.K. electricity networks were significantly expanded after World War II to support the economic growth of the country, utilizing the developments in large-scale generation technology of that time. Nowadays, the ambition of the U.K. government to integrate a very significant amount of on- and offshore wind and nuclear generation, as presented in Figure 1, will require network investments that are greater than the current value of the entire U.K. national transmission network.

In addition to approximately £3 billion of network reinforcement already underway, the value of incremental investment in the onshore transmission network to connect approximately 10 GW of onshore and 20 GW of offshore wind, together with an additional 3 GW of nuclear generation, is estimated to be £4–5 billion. In addition, a new offshore transmission network

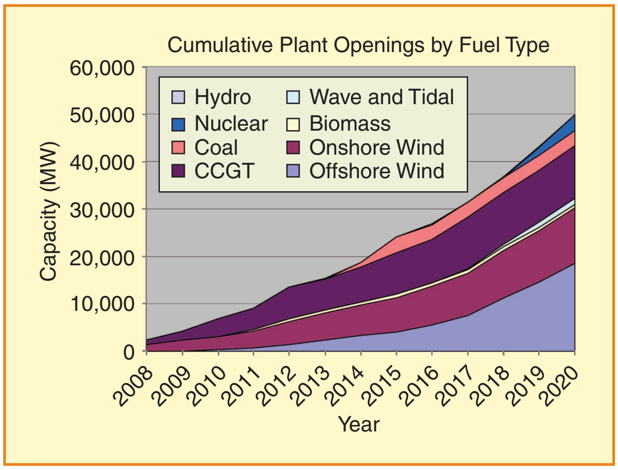

figure 1. Gone Green scenario in 2020. (Source: Electricity Networks Strategy Group.)

will be required to integrate offshore wind generation, at a projected cost of £400 per kW, increasing the total transmission investment to about £15 billion.

Delivering the renewable targets in a cost-effectively manner and on time, however, will require not only very considerable investments but also fundamental changes in network access arrangements, in the historical philosophy of network design, and in the corresponding regulatory regime.

All Is Under Fundamental Review

The reviews of the transmission network arrangements cover various aspects of the technical, commercial, and regulatory framework: transmission access, security and quality of supply standards (SQSS), RPI-X regulation, anticipatory investment proposals, and the transmission network charging scheme. The key issues associated with these reviews are briefly introduced below.

Access Arrangements

The ability to accommodate the near-maximum simultaneous outputs of all generators has been the key principle of transmission network design in the United Kingdom and in a number of EU countries. The current transmission network

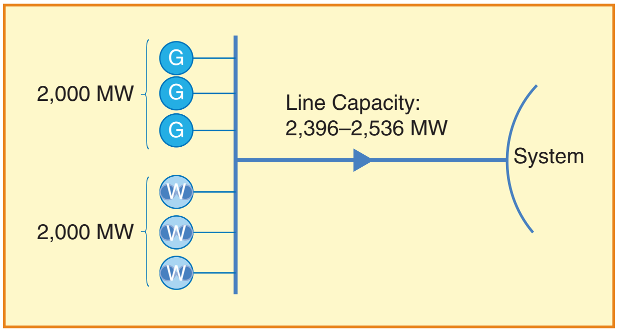

figure 2. Sharing network capacity between flexible conventional generation (G) and wind power (W). (Source: SEDG.)

access arrangements have been based on this concept. All generators have historically had financially guaranteed firm access to the system, for which they pay transmission network use of system (TNUoS) charges. Hence there has been no real need for the rationing or sharing of transmission network capacity between various generators in real time.

In areas with a mix of flexible conventional and wind generation, however, it is not economically efficient to invest in transmission to accommodate simultaneous peak outputs. Therefore, transmission capacity should be shared between conventional and wind generation. On windy days, wind generation will occupy transmission capacity; on less windy days, conventional generation will take over. The concept of sharing network capacity is illustrated in Figure 2, in which some 2,000 MW of conventional generation and 2,000 MW of wind generation are connected in the same area. The analysis demonstrates that in this case, the total of 4,000 MW of generation capacity can be connected to the system via a transmission circuit with a secure capacity of only 2,396 MW or 2,536 MW (for wind generation capacity factors of 30% and 35%, respectively) in order to achieve 85% load factor operation of the conventional plants (the typical maximum value of base plant load factors) and so accommodate 100% of the wind power output. In order for this high level of sharing of network capacity between conventional and wind generation to be achieved, conventional generation needs to be flexible, as is the case at present in Scotland with hydro, coal, and gas plants accompanying the growing capacity of wind generation.

Given that the present access arrangements do not facilitate the sharing of access, the 2007 U.K. Energy White Paper demanded that the regulator, in partnership with industry and government, undertake a review of transmission access and develop an appropriate, permanent access regime that would facilitate the delivery of an efficient level of investment in transmission infrastructure.

While this review is in progress, an interim connect-and-manage arrangement has been established to provide immediate access to new generators needing connection (all new generators are granted firm access, with network congestion costs socialized). The permanent arrangement is envisioned as a market-based mechanism in which network users would choose between short-term nonfirm access and long-term firm access.

In a commoditized market such as the bilateral U.K. model, energy and network access are traded separately as different products. The key concern, however, has been the absence of locational signals associated with the use of the transmission network in the short term. To tackle this problem, the development of a market for short-term (nonfirm) access with a pricing mechanism derived from the locational marginal pricing (LMP) concept has been proposed, as follows:

$$\text{Access price at node k} = \text{LMP at the energy trading hub} - \text{LMP at node k.}$$

This approach would be equivalent to the pool-based LMP approach but would maintain the separation of energy and access. Firm access could be purchased by network users at a price equal to TNUoS charges that reflect the long-run marginal cost of reinforcing the transmission network.

Thus, by making a choice between nonfirm access (i.e., willingness to use existing network assets) and firm access (i.e., supporting investment in new network capacity), network users will effectively drive the need for investment in transmission. If this regime is to succeed, it is critical that both short- and long-term access be efficiently priced. Hence there has been interest in reviewing the TNUoS charging mechanism.

Network Operational and Design Standards

The rules that determine the level of capacity that is released to network users in real time are codified in the present Great Britain Supply Quality and Security Standards (GB SQSS) philosophy that was developed in 1950s and unchanged since. In the context of the review of the access regime, it becomes critical for network users to know how much capacity is available in the transmission network in real time as also whether this level of capacity is efficiently determined by the historical deterministic security $N - 1/N - 2$ type rules. Hence one of the key objectives of the fundamental review of SQSS has been to evaluate the existing rules by using cost-benefit analyses that include consideration of the appropriate balance between investment costs, operational costs, and risks.

Furthermore, given the pressing need for additional transmission capacity to accommodate renewable generation, concern has arisen that the existing GB SQSS may be a barrier to the application of a range of advanced, technically effective, and economically efficient nonnetwork solutions, e.g., corrective or postfault actions, that can release latent network capacity in the existing network. Rules that are used to determine the amount of capacity that should be released to network users in real time may be inefficient and limited to the application of asset-heavy network solutions to network problems, i.e., network redundancy. Updating these rules within a true cost-benefit framework would result in a reduction of costs associated with network constraints and would facilitate the more efficient connection of renewables. It is expected that the levels of transmission capacity released to users in operational time scales would vary with the magnitude of constraints costs, the probability of outages (i.e., weather conditions), the cost of postcontingency services, and so on. In turn, this would reduce the need for future network investment.

In the light of these considerations, renewables' entry could be accelerated by substituting requirements for network investment with operational measures supported by information and communication infrastructure, including special protection schemes, coordinated voltage-control techniques, wide-area monitoring and control systems, advanced dynamic security assessment techniques, and demand-side management.

The Regulatory Framework

The present network regulatory approach incentivizes network investment over operational alternatives, which is a significant barrier for the application of innovative, technically effective, and economically efficient solutions that can enhance the utilization of the existing network and speed up renewables' connection. Network designers and operators are incentivized to consider asset-heavy solutions and are not rewarded adequately for releasing network through potentially more efficient nonasset solutions. In this context, one of the key objectives of the review of the existing network regulatory approach is provide incentives for innovation and the application of operational measures where efficient.

Strategic Network Investment

So far, the transmission investment philosophy in the United Kingdom has been predominately reactive, with network capital expenditure programs being driven by requirements from generation and demand. Given the significant uncertainty in relation to the exact volume, time, and, to some extent, location of the new generation to be connected, the present planning approach is seen as a potential barrier for timely connection of renewables. In order to facilitate speedy but cost-effective connection under increased uncertainty, the conundrum of what to build first—generation or networks (see Figure 3)—is proposed to be addressed by an anticipatory investment framework.

The key feature of this proposal is that it would allow transmission owners to invest before the need is established through firm commitments of new generation to connect and pay TNUoS charges. Under this regime, transmission network companies would make speculative investments in network reinforcements to accommodate growth in renewable generation. If these investments prove to be appropriate, they will produce an enhanced rate of return on the capital invested. If not, this would affect investment recovery.

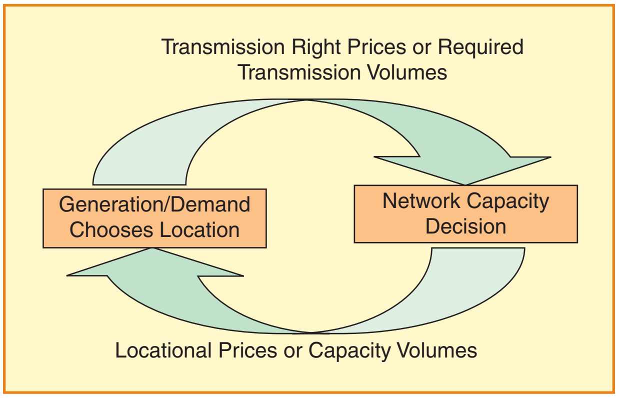

figure 3. Investment conundrum. (Source: National Grid.)

It is expected that such a scheme would provide strong incentive for network companies to engage directly with developers regarding the timing and volume of future connections (and plant decommissioning). This in turn should lead to network reinforcements that are both timely and cost-effective. This proposal raises a number of questions that need to be addressed, however, such as the appropriate rate of return in relation to the level of uncertainty and how the regulator will measure whether a given transmission investment ultimately achieves its purpose in a reasonable amount of time. Clearly, careful design of such an anticipatory framework will be needed.

United Kingdom Committed to a Market-Based Transmission Access

In the present climate, renewable generation technologies may not be commercially competitive. Several incentive mechanisms have therefore been developed to accelerate their deployment. With this external support, renewable generation has entered markets and been particularly successful in Europe, especially in Germany and Spain. Other countries are now seeking to significantly expand their renewable generation share, including the United Kingdom, Portugal, and Ireland.

In addition to the direct support renewables have received, market and operational rules have been changed in many jurisdictions in order to provide a more favorable environment for their connection. For example, renewable generation would typically be granted firm access to the transmission network and would be exempted from having to pay for use of the network. In many European countries, this approach has created significant distortions and led to inefficient network investment due to the absence of locational signals. However, the U.K. approach has been not to discriminate between different generation technologies and not to change market rules in order to reduce system integration costs to favor the connection of renewables. It is interesting to note that there is currently in the European Union an important debate about reestablishing the commitment to market-based transmission access for renewables in a manner conceptually similar to the U.K. regime.

Brazil

Renewable Energy in Brazil

In the past five years, the Brazilian power system has experienced the increasing penetration of two new renewable resources: bioelectricity (BE), which is cogeneration from sugarcane bagasse (Brazil is the world's largest producer of sugar and ethanol), and small hydro (SH), which is the term for hydroelectric plants with capacities of less than 30 MW. Hundreds of new BE and SH plants, totaling 5,200 MW, are already in operation; an additional 2,700 MW of capacity is under construction. These plants have been participating in the energy auctions carried out by the Brazilian distribution companies (distcos) to supply their loads, competing against all other resources (gas, coal, conventional hydro, and so on). More recently, wind power (WP) has emerged as the fourth "asset" in the country's renewable portfolio, with 800 MW in operation and under construction and an additional 1,800 MW contracted through an auction in 2009.

One major hurdle for the construction of these plants has been that current regional grids were unable to accommodate new power injections amounting to thousands of megawatts. It thus became necessary to plan grid reinforcements. There was a regulatory imbroglio, however, concerning the responsibilities for planning, constructing, and charging for the transmission.

Power Network Planning in Brazil

The Basic Grid: Planning, Construction, and Remuneration

The current regulation for the planning and construction of transmission assets and the calculation of transmission charges is based on the concept that generators supply a set of demands through a high-voltage (HV) transmission network (230 kV and above) known as the *basic grid*. Expansion of the basic grid is centrally planned by Brazil's Empresa de Pesquisa Energética (EPE), a government-owned company that every year proposes a network expansion plan for the next five years. ANEEL (the regulator) is responsible for organizing periodic auctions to procure the construction of the approved transmission reinforcements. Auction winners begin receiving the requested remuneration when their new facilities are placed in service.

This total revenue is collected from the generators and loads through a fixed charge, namely the transmission system use tariff, known in Brazil as the TUST or the open access transmission tariff (OATT). The TUST (R$ per installed kW) and load (R$ per yearly peak demand) of each generator is calculated to ensure that generators and loads share the revenue required on a 50-50 basis. The methodology applied is the nodal charge scheme, also known as the invested related asset cost (IRAC) scheme, which attempts to reflect the respective usage of network resources. Therefore, the further the generator is from load centers, the higher are its transmission tariffs.

The Distco Network: Planning, Construction, and Remuneration

The distcos, rather than EPE, are responsible for the planning and construction of distribution-level reinforcements in their concession areas. For each tariff review, ANEEL assesses whether those reinforcements were economically justified. If the answer is yes, then 100% of their costs are passed on to the distcos' consumers. This allocation of distribution costs makes sense when it is assumed that a distco's local loads are the unique users of the network. The injection of thousands of megawatts of renewable power at distribution

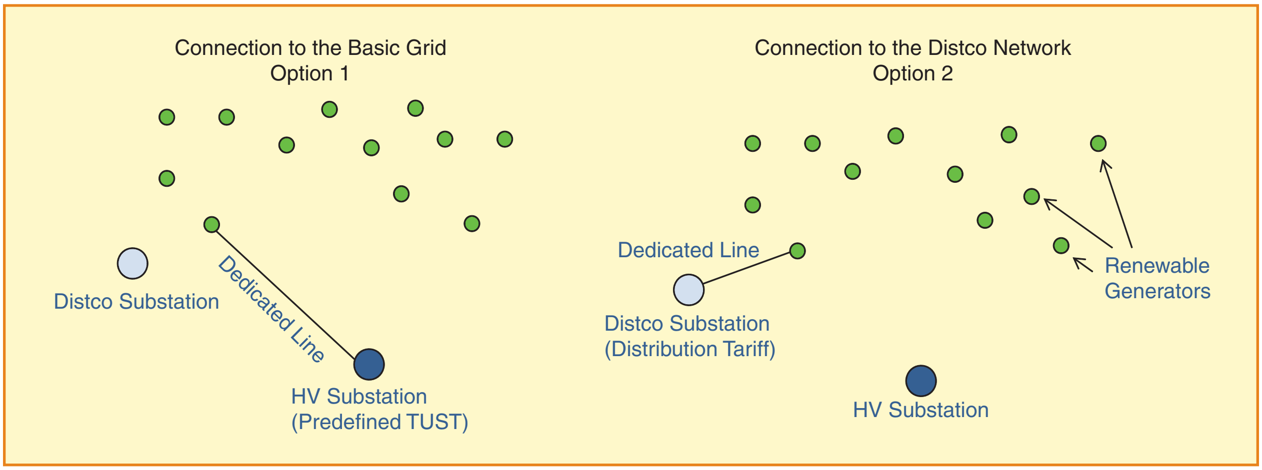

figure 4. Traditional options for grid connection in Brazil. (Source: PSR.)

voltage level has upset this conceptual scheme, however. These new realities have created regulatory challenges for the planning and remuneration of renewable integration. Those issues are discussed next.

Renewable Energy Grid Connection

Regulatory Issues

Generators have traditionally had two options for where to connect: directly to the basic grid (through the closest HV substation) or directly to the distco's network. These options are illustrated in Figure 4.

When connecting to the basic grid, generators are limited to the capacity of the substation in which the new plant will be connected. The main difference between this and the second option is the fact that the basic grid is centrally planned and TUSTs are estimated by EPE before the auction. TUSTs are fixed for ten years, and the consumer absorbs the difference between the estimated and actual tariffs. This scheme lets investors bid in auctions with prior knowledge of their transmission costs.

When generators connect directly to the distco's network, they are again limited by the capacity of the distco's substation. The connection is made on a first-come, first-served basis. But unlike the situation that obtains when a connection is made to the basic grid, the resulting connection tariff (the distribution system use tariff, whose acronym in Brazil is TUSD) is known only after the auction occurs (it will depend on the investments the distco makes in order to allow all approved connections). In addition, TUSDs vary on a yearly basis, according to new distribution network reinforcements.

Although the aforementioned options seemed to fit perfectly for all generators, the integration of large-scale renewable power into the network became a regulatory "no-man's-land." Most of the renewable generators requesting connections in 2008 (about 80 BE and SH plants in all) were located very far from the existing basic grid. Therefore, the cost of each individual connection to the basic grid (a long transmission line from the power plant to the HV substation) would have jeopardized its competitiveness. Besides that, the surrounding transmission system presented many electrical problems, such as high congestion levels for large parts of the year.

On the other hand, the local distco facilities could not support the huge amount of renewable power to be integrated (about 4,100 MW) through their existing networks. EPE had no mandate—or additional personnel—for planning distribution-level reinforcements. At the same time, the distcos' planning teams were not able to design networks that, in some cases, were larger than distcos' networks. There was also a conundrum with respect to distribution tariffs, as it would obviously be unfair to allocate the renewable integration costs to local consumers, as mandated by current regulations.

The long-term regulatory solution to the above problems will probably be to extend the basic grid definition to include lower voltage levels. But this will take time and require a fundamental review, as it is necessary to work out issues concerning the distcos' current monopoly on the construction of lower-voltage transmission facilities in their concession areas.

The ICG Scheme

Because of the urgent need to integrate those 80 BE and SH plants, totaling 4,100 MW, investors proposed an agreement to ANEEL and the Ministry of Mines and Energy (MME) that became known as the ICG (an acronym for "shared facilities for generators" in Portuguese) scheme. The characterization of the ICG was made by ANEEL through the enactment of a resolution added to the current regulatory transmission framework.

The key points of the agreement were:

- ✔ **Planning:** Generators would hire a technical team to plan the integration network, in cooperation with EPE. The planning of the integration network would

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be carried out on a least-cost basis, through the use of an optimization model to optimally locate the ICG facilities and minimize investment costs. The proposed plan would be subject to ANEEL's approval.

- ✔ **Pricing (cost allocation):** Generators would pay for 100% of the ICG costs plus the basic grid tariff (TUST).
- ✔ **Network construction:** Distcos would (exceptionally) waive their right to build the ICG assets and an auction mechanism, similar to the basic grid approach, would be applied to grant the rights to operate and maintain the ICG facilities.

Because the BE and SH plants were spread over a large area, the solution was to plan an integration network with layers of shared connections (by means of collector stations) at different voltage levels. As illustrated in Figure 5, this avoids the need for individual connections to the HV grid for the exclusive use of each generator.

As agreed in the ICG scheme, generators will pay for all integration network construction and maintenance costs. Because the network had a tree structure, it was easy to calculate the fraction of each generator's injection that would flow across each circuit. This allowed the application of a MW-mile scheme, in which each generator pays for the cost of each circuit in proportion to its use (fraction of total power flow).

One "chicken-or-egg" problem remained, however. For a generation investor to decide whether to sign up for the "network construction pool" (which requires the deposit of financial guarantees), it has to assess the competitiveness of its final energy cost. Unfortunately, one significant item in the generator's expense stream would not be known: its share of the network cost. The reason for this is that the design of the integration network depends on which generators sign up, which is exactly what the generators must decide.

This uncertainty was reduced via the following proposal: A preliminary sign-up would be carried out and generators would be given the right to abandon the pool. A preliminary integration network would then be designed, and a preliminary cost allocation would be carried out for this initial set of generators. Next, generators would be asked to reconfirm their intention to join by depositing the needed financial guarantees. The final network would finally be redesigned for the set of "confirmed" generators, and a more accurate estimation of costs would be undertaken.

Auction Results

On 24 November 2008, ANEEL carried out a public auction for the construction of 1,550 km of 230-kV lines (for double-circuit 230-kV lines, the sum of circuit lengths was used) and 960 km of 138-kV lines. Some 230-kV circuit reinforcements in the basic grid were auctioned together with the integration network facilities. The total construction cost was about US$400 million, and the facilities are scheduled to be commissioned placed in service on 15 July 2010. In mid-2008, the same methodological and regulatory procedures were also applied to the integration of 35 BE and SH plants (with a total of 1,600 MW of capacity) in Brazil's southeastern region (the state of Minas Gerais).

Another public auction is scheduled for the second half of 2010 to grant the concession of the ICG facilities that will be used to integrate about 1,800 MW of WP in the northeastern and southern regions of Brazil. Initial studies carried out by EPE point to roughly US$100 million needed to accommodate this WP, which was contracted through the energy auction held in December 2009.

Although renewable participation in the electric energy matrix has considerably increased in the last five years, most of

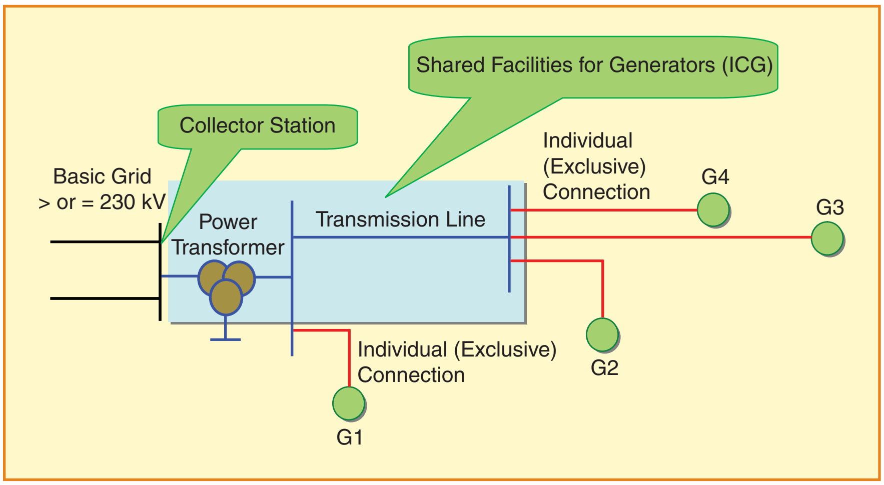

figure 5. Illustration of the ICG scheme's integration network. (Source: adapted from EPE.)

the investment needed in the basic grid is still driven by conventional generators.

Cooperative Solutions to Regulatory Issues

The development of clean, efficient electricity is critical for emerging countries such as Brazil, where load growth is fast. Renewable generation has several attractive characteristics for the country: potential capacity, regional location, and (in the case of BE and WP) complementarity to hydroelectric generation. The large-scale integration of renewable energy into the existing grid may create complex technical (e.g., planning) and regulatory (e.g., jurisdiction and tariff structure) problems that require novel solutions. The successful approach adopted in Brazil by means of the ICG scheme has made it possible to overcome the imbroglio concerning the distcos' responsibilities while designing a least-cost network for integrating renewables. On the other hand, some questions may rise when further analyzing the process. For example, some investors have questioned EPE concerning reactive power support planning for ICGs's substations, arguing that they are not needed. Regardless of whether EPE's planned reactive support is adequate, it is important to clearly define all planning rules and criteria to avoid misunderstandings.

Overall, the key ingredients of a successful solution turned out to be the simultaneous addressing of both technical and regulatory issues and the creation of a close cooperation among the technical teams, investors, distcos, regulators, and other government agencies.

Chile

Transmission and Distribution in Chile

The connection to the transmission system is generally a barrier to entry for generators, especially in Chile, given the radial nature of the transmission systems that have been developed and adapted to conventional generation and demand. In particular, in areas where there is high wind development potential, transmission systems require important expansions.

Transmission systems in Chile are divided into three distinctive segments: *trunk*, *subtransmission*, and *additional transmission*, each with its own regulatory framework. This division implies different expansion and tariff determination methods. Trunk transmission contains the main corridors above 220 kV and is the backbone of the electricity market. In addition, this segment is composed of the installations that are economically efficient and necessary to supply the total demand, which is subject to central planning and regulated tariff fixation. The subtransmission segment is composed of the systems above 23 kV, which are intended to supply distribution companies; these therefore serve both regulated and nonregulated consumers. This segment has a regulated tariff fixation but a private planning scheme. Additional transmission systems are dedicated networks that connect generation facilities to the transmission systems or enable large consumers to withdraw energy from the market; here tolls and expansion planning are privately agreed to. Trunk and subtransmission system assets are determined by decree, and tariffs are set every four years, in two separate processes.

An open access scheme regulates the three segments of the transmission system, and an unbundled trunk transmission ownership scheme has been established, with limited participation by generators. "Open access scheme" signifies that third parties may use the transmission systems with the payment of a given toll and that no technical or economic barriers can be used to discriminate among users (some restrictions are permitted in the additional transmission segment, however).

The term *distribution systems* in Chile is used to refer to all installations under 23 kV where regulated tariffs are applied and that operate within a given concession to supply power to regulated end users. Open access in distribution exists in principle, both to connect generation and to access nonregulated consumers in distribution networks, but barriers are often encountered in actual application.

Renewable Energy Insertion in Chile

The regulatory framework in Chile was modified in 2004. Special treatment for renewable energy was enacted, for both transmission and distribution systems. Chilean legislative changes began when a new classification scheme was introduced, with the objective of distinguishing certain types of renewable energy from conventional renewable sources such as large hydroelectric plants. Nonconventional renewable energy (NCRE) was defined as the generation from nonconventional sources connected to the grid, such as geothermal, wind, solar, biomass, tidal, cogeneration, and small (i.e., under 20 MW) hydroelectric generation facilities. Recent legislation has set important incentives for this type of generation, forcing an initial market share of 5%, and increasing that to 10% by 2024. Figure 6 shows the energy required to comply with the established quotas and the energy already operating or under construction.

To facilitate integration of small generation into the network, most of NCRE although not all, the Chilean

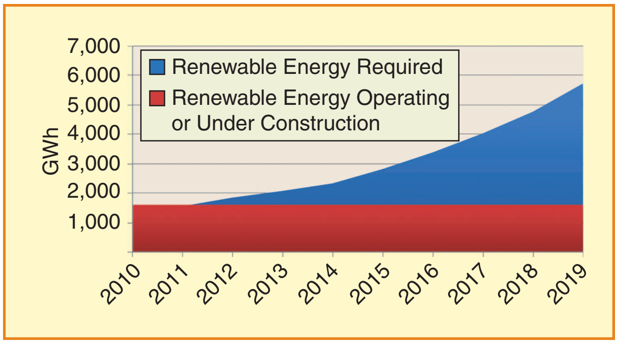

figure 6. Nonconventional renewable energy required and under construction in Chile. (Source: Systep.)

The need to integrate renewable generation into transmission and distribution networks has opened fundamental questions of both operation and investment in network infrastructure.

regulation created different generation categories that are subject to special connection arrangements. First, depending on where they connect, generators under 9 MW are classified as SMDG (small means of distributed generation), connected to distribution networks and SMG (small means of generation), connected to transmission networks. Further on, an explicit category was created to identify generators utilizing NCRE, but sized under 20 MW, and they were named NCGM (nonconventional generation means). Thus, special regulatory arrangements applied for SMDG, SMG, and NCGM (a generator may also fulfill two categories simultaneously, for example it can be both SMDG and NCGM or SMG and NCGM).

Special treatment was given to NCRE generators with the objective of facilitating their connection to the grid and their access to different energy markets. Acknowledging the low impact on the main transmission system of the NCRE, NCGM plants with an installed capacity of under 9 MW were given a toll payment exception for the trunk transmission system, and a partial exemption was granted to units with capacities of 9–20-MW. This partial exemption is proportional to installed capacity and is calculated in a linear manner until it reaches an exemption of 0% for 20-MW plants. The exemption has a limit that is activated when the total capacity of all renewable generators subject to the exemption surpasses 5% of total energy generated in the system; at that point a proportional reduction is applied to all NCRE generation until the 5% is met. No special treatment was given to NCRE generators with respect to connections via the subtransmission or additional transmission systems.

The requirements for interconnection to the grid vary depending on the system to which the NCRE will be connected. For connections to transmission systems, the grid code must be followed as would be the case with any other conventional generator in an open access scheme.

Special regulation had to be introduced for the integration of SMDG, since there was no experience in the country connecting generators from third parties to distribution networks. A complete regulated process was implemented, governing information flows, permit requests, deadlines, and possible litigation. The process has two main phases. In the first phase, the generator must inform the distribution company of its intention to connect to the grid and request the technical data concerning the distribution network so an application for the network connection can be made. In the second phase, the distribution company must state whether it agrees to allow the connection and to assume the additional costs that may be incurred because of the connection, taking into account the benefits that may be received from the distributed generator. Further phases exist if no agreement is reached, and there is strict supervision from the competent authorities during the entire process.

Challenges for Higher Renewable Energy Penetration

Although much has been done to facilitate renewable energy in Chile and eliminate barriers to entry so that it can be connected to the grid, the process has not been easy, pitfalls are still encountered, and connection has been slow for smaller projects (those with capacities of less than 20 MW).

There is an important challenge for planning and pricing of the network for two main reasons. First, there is a time lag between investment in renewable generation such as wind or solar plants and investment in transmission facilities. On the one hand, some renewables can be installed in 18 months, but a transmission line requires four to six years to complete. Furthermore, larger renewables directly connected to trunk transmission systems, such as wind farms in excess of 20 MW, often face difficult conditions since expansion plans are centrally formulated and possible expansions may have to follow a long path to execution. Recent regulation concerning native forests may further increase lead times for the construction of transmission lines, exacerbating the problem. Alternative mechanisms such as anticipatory investment are being studied in the industry, but none of these is seen as being close to implementation in the short term.

Second, some forms of renewable energy, such as solar and wind, have generation profiles that can be very variable, i.e., intermittent, in time, with a low average generation output despite a much larger installed capacity. These types of renewable installed capacity will affect the sizing of transmission lines and substations, increasing peak flows and hence potentially determining larger or additional installations. But on the other hand, pricing for the transmission systems, except for a portion of the trunk transmission system called the influence area, is calculated based on expected usage of the system under many different operational conditions, such as hydrology and demand. This results in renewable investments' conditioning larger transmission installations but only contributing limited remuneration due to their low mean generation, i.e., low network usage.

In other cases, SMG or SMDG located in areas distant from important transmission lines and only near weak

table 1. Network infrastructure and arrangement changes for renewables in the United Kingdom, Brazil, and Chile.

Network Infrastructure for Renewables	United Kingdom (Transmission)	Brazil (Transmission and Distribution)	Chile (Transmission and Distribution)
Investment needed (current estimates)	£7–8 billion in the onshore network and £7–8 billion in the offshore network by 2020 to connect ~11 GW of onshore wind, ~19 GW of offshore wind, and ~3 GW of nuclear power. (Source: National Grid Vision.)	About US$500 million has been needed so far in transmission and ICG assets to connect biomass and wind power already auctioned. Billions of dollars more will be needed if an aggressive penetration (>15 GW) takes place.	US$3.0–6.5 billion in upgrades to the entire transmission system for the 2010–2020 period. This also takes into account the forecast high demand growth (about 5–6%).
Network Arrangement Changes for Renewables	**United Kingdom (Transmission)**	**Brazil (Transmission and Distribution)**	**Chile (Transmission and Distribution)**
Access	Transmission access review being undertaken. Change from invest-then-connect to an interim connect-and-manage access arrangement (all participants are given firm access). Permanent access regime should include short-term access trading, enabling transmission investment driven by users' choices.	Open access policy for transmission always in place but now boosted by a special regime that enables connection of renewables through collector substations (ICGs).	Introduction of open access for distribution and rules that regulate DG payments within distribution networks. Toll discounts for renewables in trunk transmission system (open access). Recognition of problems with unfair tolls in new transmission investments.
Planning	Transmission access and SQSS review being undertaken. Transmission planning driven by SQSS may be replaced by market-driven investment.	Optimization model driven by economics criteria developed to integrate renewables through centrally planned collector substations.	Central planning scheme modified to recognize special requirements for substations that connect wind power.
Investment philosophy	Regulator approves investment proposals at present. Proposal to introduce anticipatory investment regime to enable speculative network investment prior to users' commitments (i.e., strategic investment proposal).	Regulator approves investment proposals made by the Agency for Planning Studies. Transmission construction takes about 18–36 months, since rights-of-way are easier to obtain than in densely populated developed countries. Wind is located closer to consumption centers (along the coast), where transmission is more developed. Anticipatory investment not needed so far.	No changes. The authority approves investment proposals. Transmission expansion is based on generation scenarios, including renewables, with no anticipatory investment (generation backgrounds given by committed new generators).
Security	SQSS review being undertaken. Probabilistic cost-benefit framework considered to replace historical deterministic N–*k* criteria.	No changes. Security standards are already based on probabilistic and cost-benefit concepts (N-0, N-1, etc., depending on the transmission line).	No changes. Security standards are already based on probabilistic and cost-benefit concepts (N-0, N-1, etc., depending on the transmission line).
Regulation and revenues	RPI-X review being undertaken to provide additional incentives to TSOs so as to obtain revenues from releasing capacity by both operational measures and investment.	Definition of ICG's cost recovery through fixed rates on investments. Same tariff scheme already in place for transmission/distribution remuneration.	No changes. Cost recovery through fixed rates on investments in transmission and yardstick competition model in distribution.
Network operation technologies	Pressure to increase capacity through advance operational measures. Smart meters rollout approved, demand-side participation expected post-2020.	No changes. Application of advanced intertripping schemes to increase transfer capability of the network already in place.	No changes. Application of intertripping schemes to increase transfer capability of the network already in place.
Network (re) classification	Development of offshore networks, under offshore network design standards (different from onshore). While onshore network is defined as monopoly; offshore networks are competitive.	Definition of the "shared facilities for generators" (ICG) concept.	No new definitions because of renewables.

transmission lines or rural distribution networks face the difficult scenario of not being able to fully exploit their renewable resources, such as small hydro or coastal wind, because the required connection facilities are too costly. In such cases, the cost of either constructing an additional line or reinforcing the existing transmission or distribution networks exceeds the benefits, and this results in having to reduce the size of the projects in order to fit existing installations. The desirability of implementing more incentives to aid these remote projects is something yet to be studied, since some of these projects are located in very distant areas where they would simply be unjustified. Borderline cases could be aided by the implementation of a system that reflected environmental externalities caused by thermal generation, i.e. emissions, in energy pricing. A careful balance must be found, however, between economic efficiency—key for a developing country with a large portion of its population living in poverty—and environmental sustainability, both regional and global.

Smaller renewable energy installations—the SMDG group—have also faced a difficult process of integration into the market due to the required interaction with the distribution company. Often, distribution companies do not welcome generators to their networks. This tendency, combined with an important initial information asymmetry, implies a long process before the actual connection can be made. More friendly interactions are often seen when the energy is sold to the distribution company: it smooths the road, since incentives are aligned. All the aforementioned issues are aggravated by a lack of experience on the part of project owners, which results in a delayed connection process.

Final Remarks

Transmission connection in Chile is a major issue for any type of generation, with challenges that must be faced by renewable energy as well. Special regulation has been implemented in Chile to accommodate renewable energy, especially nonconventional renewable energy, granting special benefits for market integration, such as toll exemptions. Regulations have been implemented for distributed generation, but limited penetration has been achieved.

Given the competitive generation market in Chile, where no special tariff recognition (such as a feed-in tariff) is given for renewable energy except for the establishment of a mandatory market quota to be supplied by renewables, the biggest barrier faced is still cost competitiveness in comparison with conventional technologies, for which transmission barriers have been partially overcome.

Similarities and Differences Among Jurisdictions

From the experiences in the three jurisdictions presented in this article, it is clear that the integration of significant renewable generation capacity will require not only a considerable transmission and distribution network investment but also fundamental changes in the technical, commercial, and regulatory framework. Table 1 summarizes and contrasts the major initiatives in these countries, including infrastructure and the reviews and changes in network technical, commercial, and regulatory arrangements introduced to facilitate the timely connection and cost-effective integration of renewable resources.

Overall Conclusions

The need to integrate renewable generation into transmission and distribution networks has opened fundamental questions of both operation and investment in network infrastructure. Furthermore, the existing market, commercial, and regulatory framework that has been designed for networks with conventional generation that present incremental commissioning profiles may be a barrier for timely and cost-effective connection of renewable generation. This has caused a wholesale revision of network arrangements, including review of network operation and design practices, security standards, access regimes, investment incentives, network cost recovery methods, and charging policies.

The three experiences presented in this article illustrate some of the key activities initiated and solutions proposed that aim to address the challenge of unlocking the entry of renewable and guarantee the transition to an efficient, 21st-century, low-carbon energy system.

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For Further Reading

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Biographies

Rodrigo Moreno is with Imperial College London, United Kingdom.

Goran Strbac is with Imperial College London, United Kingdom.

Fernando Porrua is with PSR, Brazil.

Sebastian Mocarquer is with Systep, Chile.

Bernardo Bezerra is with PSR, Brazil.