Transmission Investment and Renewable Integration

Hugh Rudnick and Constantin Velásquez

1 Introduction: Conditions of Integration of Renewables in Modern Power Markets

The world needs renewables, and renewables need transmission. Renewable electricity generation is a key element for the much-needed transition to low-carbon economies of the future. According to the IPCC, renewables are projected to supply 70–85% (interquartile range) of electricity in 2050 across the future pathways for limiting the hazards of climate change (IPCC 2018). Cleaner power generation enables effective climate change abatement through electrification of other fossil fuel reliant sectors, such as heating and transportation. Electrification would lead to more carbon emissions if the power sector remains heavily reliant on fossil fuel generation.

The world has witnessed a tremendous growth of variable renewable energy (VRE) generation over the past decade. Indeed, renewable energy generation accounted for 9.3% of global power generation in 2018, up from only 3% a decade ago (BP 2019). Initially driven by support mechanisms and subsidies, pure economics and evolving market-based regulations are now driving the growth of VREs around the world, partly due to the plunge in investment costs over recent years (IEA 2018; Kavlak et al. 2018). For the near future, the IEA expects a 46% growth of renewable power capacity between 2018 and 2023 in its main case forecast. This expansion would be mostly in VRE resources, with more than half coming from solar PV generation, and wind remaining the second-largest contributor (IEA 2018). Partly due to the recent growth of renewables, the power sector is often depicted as a success for

H. Rudnick (✉) · C. Velásquez
Pontificia Universidad Católica de Chile, Santiago, Chile
e-mail: hrudnick@ing.puc.cl

C. Velásquez
e-mail: csvelasq@puc.cl

M. R. Hesamzadeh et al. (eds.), *Transmission Network Investment in Liberalized Power Markets*, Lecture Notes in Energy 79,
https://doi.org/10.1007/978-3-030-47929-9_14

decarbonization of energy and sometimes as the only energy sector for which the future path seems clear (compared to heat and transportation).

Despite the incredible growth of VREs over the past decade, a challenging path lies ahead for the power sector. The world is still highly reliant on fossil fuels for power generation. As of 2018, coal remains the dominant worldwide fuel for power generation with 38%, the same share as 20 years ago (BP 2019). Increased and sustained efforts are thus clearly needed to accelerate and deepen the integration of VREs, to quickly lower carbon emissions of the electricity sector.

The disruption of renewable generation poses new challenges and opportunities for the transmission system, both from the system and the investor perspective.

- Variable and uncertain generation profiles of VRE require flexibility in operations, planning and regulation of the power sector. New transmission capacity is a primary source of flexibility for the power system. Adequate transmission capacity and flexible operation procedures (such as transmission line switching) allow for sharing of the most economic and flexible resources across the power system, key for a secure operation under varying flow patterns.
- Unlike coal and gas, wind and sun cannot be transported to more convenient locations. Renewable power plants need to be located in resource-rich regions. Regions with high-quality renewable resources are often far away from load centers. Therefore, transmission infrastructure is needed to transport the electricity from renewable power plants to the main grid and to final customers.
- Smaller power plants require flexible expansion and smooth coordination of investments across the generation, transmission and distribution segments. Renewable power plants are often much smaller than fossil-fueled and hydro-dams power plants. Moreover, large VRE projects (more than 300 MW) can be developed quickly and flexibly in small incremental stages, given the modular nature of wind turbines and solar PV panels. Smaller power plants require lower direct investments, shorter construction times and are often widely dispersed geographically. Therefore, common transmission infrastructure might be beneficial to economically harness the potentials of renewable generation hubs. Moreover, coordination is needed between transmission and distribution investments and operations, given the increasing role of distributed generation and other flexible resources such as storage.

Therefore, rapidly achieving high shares of renewable energy in the electricity generation mix requires timely and efficient development of the transmission system. Such development includes transmission investment in both the main grid and in locations with high renewable generation potential. New challenges for planning, pricing and regulation of the transmission system are arising due to the disruption of VRE generation, which is rapidly re-shaping power systems.

This chapter highlights some of these challenges associated to transmission investments needed for integration of renewable generation, as well as the approaches to deal with these issues. Some of the issues and lessons analyzed in the chapter draw on the Chilean experience (Velásquez 2017; Watts and Rudnick 2014). Chile has seen record growth of VREs in recent years, increasing the share of electricity generation from wind and solar renewables from 0% in 2006 to 5% in 2015 and 12% in 2018 (8.7 TWh). Renewables were initially driven by quota mechanisms which aimed at 10% of renewable generation participation by 2024. Although a later law increased the target renewable share, it is now clear that these targets will be vastly surpassed and far in advance, due to the explosive economic-driven growth of renewables.

The explosive growth of renewables required significant transmission investments, and massive new projects will also be needed in the future. Chile is a long country with widely dispersed renewable resources. Indeed, the renewable potential considered for the Ministry's strategic long-term planning highlights the availability of high-quality solar generation potential concentrated in the north, in contrast with hydro- and wind generation potential in the south (see Fig. 1a). Given high concentration of demand in the center zone where the capital is located, transmission investments to harness the renewable potential widespread across Chile will be significant in the medium- and long-term (see Fig. 1b, c). This trend will intensify given the recently announced plan to decommission all coal-fired power plants by 2040. Coal generation accounted for 38% of total power generation in Chile during 2018, and 872 MW of coal-fired capacity are located in the center zone. The first decommissioning stage comprises 1,047 MW of generation capacity (322 MW of which are located in the center) by 2025, which will be replaced by renewable projects located in the far-north (mostly solar PV) and the south (wind farms).

Recent experiences in Chile highlight the complexities of the planning, permitting and siting process for new transmission systems. Commissioning of a major 500 kV line between the center and the north suffered a 17-month delay (further discussed below). This experience raises concerns regarding the timely development of future expansion, such as the planned HVDC line between the north and the center, much needed for harnessing the solar generation potential. Complexities may result in delays and a development time between 10 and 15 years for such a large HVDC transmission project. Moreover, uncertainty in the expected location of future renewable generation may result in excess transmission toward the north and insufficient transmission toward the south.

Renewable investors in Chile have already suffered the impacts of inadequate transmission capacity and delays of important transmission projects. Figure 2 depicts the evolution since 2017 of hourly locational spot prices in selected nodes of the northern and center zones. Before November 2017, the Chilean power market was composed of two independent power grids: the SING in the north, mainly composed by large mining companies and coal-fired generation, and the SIC in the center and south zones, with a mix of industrial, commercial and household customers as well as thermal and hydro-generation. Over the past decade, renewable generation projects in the northern SIC zone were built far more quickly than the required transmission infrastructure. Price decoupling reveals that transmission congestions between the northern and center SIC provoked curtailment of wind and solar PV generation during daylight hours. The lack of timely transmission capacity meant significant foregone revenues for renewable generators due to both curtailed electricity production and lower spot prices.[1]

[1]The lack of operational flexibility is also a significant contributor to renewable generation curtailment, given the high shares of inflexible coal-fired capacity in the north, as well as gas-fired plants

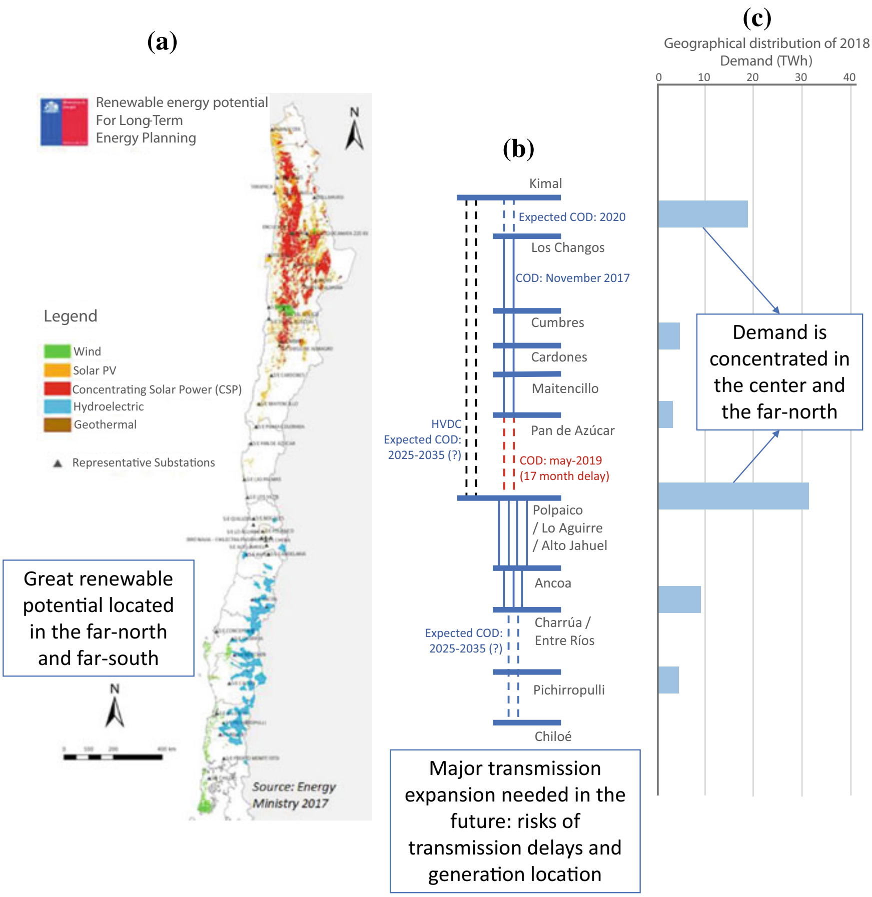

Fig. 1 Location of renewable energy potential across Chile (**a**) main transmission system (**b**) and geographical distribution of demand (**c**). The chart presents a simplified depiction of the main transmission system (500 kV and HVDC) and the geographical distribution of yearly energy demand for 2018, for illustration purposes only. Several substations were grouped or omitted for presentation purposes. HVAC transformers and HVAC/HVDC transformation omitted for illustration. Different zones are grouped for the geographical demand distribution. Commercial Operation Date (COD) provided for new transmission lines is referential, based on the author's experience, to illustrate the potential challenges of new transmission projects. *Source* Own, based on Energy Ministry (2017) and data published by National Electric Coordinator (CEN)

Curtailment fell drastically following the commissioning of the transmission interconnection project between the SIC and the SING in late November 2017, leading to

---

with inflexible LNG supply agreements which are given priority dispatch. However, the single most relevant contributing factor to renewable curtailment in Chile is the lack of adequate transmission capacity.

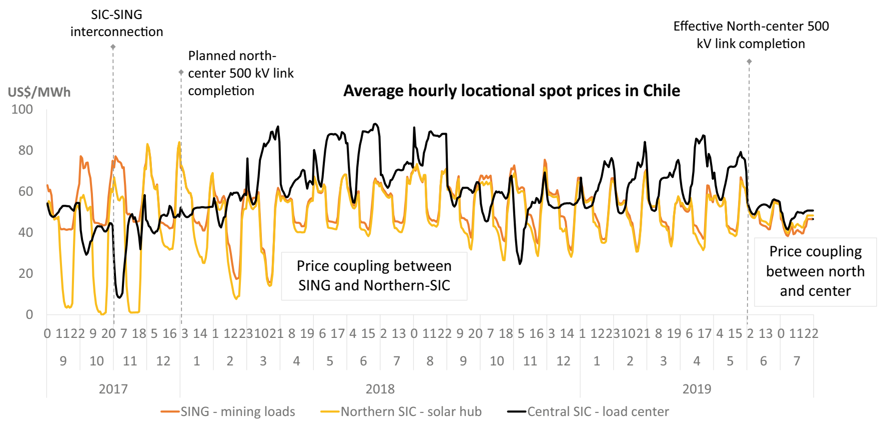

Fig. 2 Average hourly locational spot prices in Chile. The marginal cost of three representative busbars is presented to illustrate price difference across geographic regions of center–northern Chile. SING is represented by Crucero 220 kV, northern SIC by Cardones 220 kV and center SIC by Alto Jahuel 220 kV. For each month, the arithmetic average of hourly marginal costs was calculated across all days of the month. Planned and effective completion dates for transmission expansions are depicted at hour 0 of each month, given that no daily resolution is presented. *Source* Own, based on ISO data (the National Electrical Coordinator, or CEN for its Spanish acronym)

increased price coupling between the SING and the northern SIC. However, decoupling persisted between these northern zones and the center SIC. Although such decoupling would have been solved from February 2018 onwards due to the planned commissioning of a 500 kV link between the north and the center (connected only through 220 kV lines), the last tranche of the 500 kV link was delayed for 17 months, partly due to the complicated right-of-way negotiation process and intense public opposition. Commissioning of the full 500 kV link occurred in May 2019, leading to price coupling across the north and center zones of the interconnected grid in recent months. The prolonged delay of this project meant sustained foregone revenues for renewable generators, mostly due to lower-than-expected prices, rather than curtailment.

To tackle the challenges brought about by the disruption of renewables, as well as wider weaknesses in transmission regulation, the Chilean regulator conducted over the course of two years (2014–2016) a widely participatory process to develop a new legal framework for transmission expansion and operation. The new transmission law was enacted in June 2016, introducing deep reforms to expansion and operation of transmission systems. The key elements of the Chilean transmission law related to the accommodation of renewables can be summarized as follows (Ferreira et al. 2016):

- Governance of power system operations and interconnection procedures was strengthened through increased independence of the ISO. Moreover, the two previously independent ISOs were merged in a single ISO for the interconnected national grid.

- Beyond reliability and least-cost production, a wider set of benefits must be explored to justify transmission expansion plans, including competitive and resiliency benefits.
- Transmission planning must address long-term uncertainty through scenario analysis, incorporating a variety of long-term visions of the evolution of the energy sector to guide transmission planning.
- The planner is explicitly granted the ability to consider spare transmission capacity for possible future developments of supply and demand fundamentals.
- Transmission for renewable hubs can now be proactively developed through centrally planned investment in the required transmission infrastructure. Renewable hubs are conceived as zones with high potential of renewable generation and relatively far from the existing transmission networks, for which proactive transmission expansion may be required to harness the full renewable potential.
- The cost allocation method, based on locational signals and cost sharing between generators and demand, was simplified by transferring costs of the main grid to demand through a simple postage stamp method (with no locational signal), through a 15-year transition period for transferring these costs.
- Some responsibilities of the siting process were transferred from transmission concessionaire companies to the state. While routing of new transmission projects was previously the responsibility of the concessionaire, for complex transmission projects, the authority must now conduct a strip study to determine the spatial route in which the project must be developed, considering a variety of environmental and societal criteria. The resulting strip will be subject to a strategic assessment process and the approval of the Council of Ministries.

The foundation of these reforms ranges from theoretically sound arguments to primarily practical considerations. These theoretical and practical foundations, as well implementation issues that have already emerged, will be further discussed in this chapter.

The rest of the chapter is structured as follows. Section 2 overviews planning and expansion of the main transmission grid to accommodate high levels of renewable generation, from scenario generation to planning studies and the difficulties with approval and siting of new projects. Section 3 analyzes the alternatives for efficiently harnessing renewable generation hubs, discussing the economics of transmission and generation coordination. Section 4 concludes this chapter.

2 The Backbone for Low-Carbon Power Systems: Developing Transmission Grids for High Levels of Renewable Generation

Developing the transmission grid that renewables require is no easy task. At the system level, planning the optimal transmission network is a highly complex engineering and regulatory challenge, which requires dealing with uncertainty and

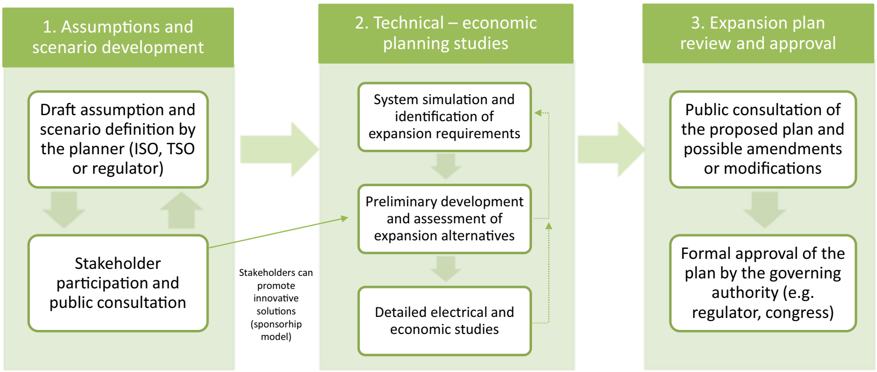

Fig. 3 Generic transmission expansion planning process in practice. *Source* Watts and Rudnick (2014)

multiple objectives (as previously discussed). Moreover, once transmission expansions are defined, their cost must be allocated among market participants, and the works must be financed and successfully completed within reasonable times. However, the development of new transmission lines has become more challenging due to growing environmental and social concerns, yielding longer and more uncertain lead times for new transmission projects due to siting and permitting difficulties. This section will discuss some of the issues related to planning, allocating costs and executing much-needed transmission expansions for the renewable scale-up.

Transmission planning in practice is developed in three stages: assumptions, technical–economic studies and approval process, as depicted in Fig. 3 (Watts and Rudnick 2014). Each of these stages has its own set of challenges, for which a variety of possible solutions have emerged worldwide, as further discussed below.

2.1 *Scenario Generation for Transmission Planning*

In the first stage of the transmission planning process, key assumptions and multiples scenarios are developed and agreed upon by the planner and the stakeholders. The precise definition of assumptions and scenarios shapes the results of the planning process. Therefore, this is a key early participation tool for stakeholders, which they can use to express their interests and expectations of the process, whether it is profit maximization (for generation companies) or sustainability (for communities). Therefore, this process often entails extensive stakeholder participation and public consultation.

Scenarios can be broadly classified under three categories: predictive, explorative and normative (Börjeson et al. 2006). Each scenario type attempts to answer a different kind of question about the future, and thus, different examples exist for transmission planning (see Table 1). The motivation and generation techniques for

Table 1 Scenario typology

Scenario type	Question about the future	Transmission planning example
Predictive	What will happen?	• Short-term baseline scenario based on relatively certain supply and demand evolution
		• What-if analysis and sensitivities of projects delays, load and renewable resource pattern, among others
Explorative	What can happen?	• Diverse and plausible scenarios, generated by quantitative models based on various economic, environmental and technological assumptions
		• Higher and lower estimates of renewable generation integration, demand growth and other key uncertainties
Normative	How can a specific target be reached?	• Goals for renewable generation and fuel diversification
		• Envisioned energy mix in the long-term

Source Own, based on Börjeson et al. (2006)

each of these three scenario types are outlined below, given the diversity of transmission planning approaches and scenario techniques employed across different countries.

Predictive scenarios which attempt to forecast future conditions have historically been the basis for transmission planning, specially under vertically integrated utilities. These scenarios can simplify the representation of uncertainties of relatively low complexity, such as **k**nown and **u**nknown uncertainties (Diebold et al. 2010; Gomory 1995; Velasquez et al. 2016). Predictive or case-driven scenarios are often sensitivities or limited deviations from base case assumptions. Case-driven scenarios describe many possible combinations of outcomes of some set of uncertainties such as winter/ summer peak, generation expansion or load growth rates (Bustamante-Cedeño and Arora 2008; Buygi et al. 2006; Gorenstin et al. 1993; Mejia-Giraldo and McCalley 2014; PJM 2015a).

As previously mentioned, power system operations and planning in the vertically integrated regime have been historically driven by least-cost engineering analyses and computer simulation models (Stoll 1989). Industry restructuring and the introduction of competition make economics and value-based transmission become more important (Buygi et al. 2004; Kirschen and Strbac 2005; Oliveira et al. 2007). This trend has led many countries to devise transmission planning processes primarily around theoretically sound quantitative models for generating and analyzing predictive scenarios. For example, this has been historically the case of PJM's reliability and market efficiency studies for transmission planning.

As the uncertainty and complexity of the power market increase with more competitors and new renewable technologies, **explorative and normative scenarios** become more important for the medium- and long-term. As PJM puts it, for the first ten years of its transmission planning process, uncertainties were limited, and a single set of assumptions was enough for reliability and market efficiency planning. However, market and policy developments in more recent years required PJM to undertake scenario planning (PJM 2017).

Explorative scenarios can be used to represent a broad spectrum of plausible future evolutions of the power system, such as different levels of policy-driven renewable generation. These scenarios ensure internal consistency by analyzing interactions among several uncertainties, and selecting between three and six scenarios to broadly represent plausible uncertainty realizations (Gu and McCalley 2010; Linares 2002; Munoz et al. 2014; National Grid 2015a, b; PJM 2015b; Sanchis et al. 2015; van der Weijde and Hobbs 2012).

In turn, normative scenarios can be used to guide the planning process toward a strategic long-term vision (often the government's vision), such as resource adequacy levels or fuel diversification goals (e.g., for heavily hydro-reliant countries such as Colombia and Peru). These normative scenarios often portray the authority's vision for the future of the power sector. While normative scenarios can be part of the planning process, the set of considered scenarios should also be diverse to represent a wide range of possible futures (Schoemaker 1993).

Contrasting with the quantitative approach for generating predictive scenarios, explorative and normative scenarios are often built by the intuitive or qualitative approach (van Notten et al. 2003). The intuitive approach conceives scenarios as a mean to bound, understand and communicate uncertainty, rather than accurately predicting or forecasting future outcome (Bradfield et al. 2005; Myers and Kitsuse 2000; van der Weijde and Hobbs 2012; Watts and Rudnick 2014). Each scenario should present a trajectory to some future state in a narrative and compelling fashion, outlining the interaction between the most important uncertainties in an internally consistent manner.

The process for strategic scenario definition should be designed for building stakeholder consensus while promoting variety of outcomes and incorporating policy guidance. Various qualitative techniques for intuitive scenario generation have been developed, including surveys, workshops, the think-tank model—back-office scenario development by team of experts—and the Delphi method—based on multiple rounds of expert panel questionnaires (Börjeson et al. 2006). These and other techniques, integrated in a strategic scenario generation process with participation from different individuals (whether experts or not), can achieve a richer variety of future possibilities and help overcome psychological biases (Schoemaker 1993; Tversky and Kahneman 1974).

Transmission planning should draw techniques from both the intuitive and formal approaches to generate scenarios. Quantitative models for developing scenarios are a must for detailed modeling of the power market and transmission expansion plans. However, purely quantitative scenarios can result in future possibilities that are too narrow or lack internal consistency. Qualitative processes allow for more diverse scenarios which are also easier to communicate and discuss among both expert and non-expert stakeholders. A mixed approach is probably best for long-term transmission planning under complex uncertainties. Such an approach was developed by the IPCC to generate its 2000 emissions scenarios, based on a mix of expert consultation, results across different models and elaboration of storylines (IPCC 2000). A similar approach is employed by the European Network of TSOs, whose scenario generation process combines storylines, rounds of stakeholders' participation and quantitative modeling (ENTSO 2018).

It is worth noting that these mixed approaches for scenario generating process go beyond the combination of multiple isolated uncertainties (or qualitative case-driven scenarios). Such a process would qualitatively assess the range of plausible values for each of the individual uncertainties. Then, extreme scenarios are generated based on all the possible combinations of these individual uncertainties. The resulting scenarios should be assessed for internal consistency and plausibility, to eliminate impossible scenarios. Nonetheless, these scenarios would lack the compelling narrative and storyline of the intuitive approach described above. Therefore, scenario generation by combination of uncertainties could be insufficient for long-term strategic transmission planning.

This combinatorial scenario generation process was employed in Chile for the first Long-Term Energy Planning Process (Energy Ministry 2017). The scenario planning process was introduced in 2016 by the new transmission law, to generate long-term energy and electricity scenarios that are later used for transmission planning. The new process was a major success in introducing strategic visions, qualitative techniques and expert panels to scenario generation. Resulting scenarios span a rich set of future possibilities which should yield more robust transmission plans, compared to the relatively simpler scenarios historically used for transmission planning (which only considered supply uncertainties). However, the process fell short of producing compelling and credible storylines for a reduced set of long-term scenarios. These storylines are a core component of participative scenario generation processes developed in USA and Europe.

2.2 Assessing Expansion Projects and Elaborating the Transmission Plan

Once scenarios and assumptions are completed, the second stage of transmission planning proceeds with technical and economic planning studies. These studies are often conducted in an iterative fashion between technical–economic optimization and detailed electrical simulations, given the computational complexity of the transmission expansion problem. This stage involves both the identification of expansion needs (e.g., identifying reliability violations) and the assessment of alternative solutions to these needs, primarily through quantitative modeling. The outcome of this stage is a set of recommended transmission system expansion works and their development schedule, with a general outline of the technical, economic and environmental specifications of the project.

Modeling and optimization techniques for transmission planning are increasingly complex in modern power markets. Rapidly growing renewable generation and other technological disruptions (such as distributed resources) impose the need for increased flexibility in power system operations and planning (Ela et al. 2014; Holttinen et al. 2013; Milligan et al. 2016). Therefore, the evolution of power systems requires enhanced modeling through higher spatial and temporal resolution (Munoz et al. 2015). Moreover, more precise representation of the underlying dynamics of the power market is needed, including scheduling, ancillary services, corrective operational measures, spatial and temporal correlation of renewable resources, weather phenomena and market-based forces (Dillon et al. 2014; Jin et al. 2014; Moreira et al. 2018; Moreno et al. 2013; Munoz et al. 2012, 2015; Neuhoff et al. 2013; Orfanos et al. 2013; Pérez Odeh and Watts 2019; Sauma and Oren 2006; Watts et al. 2016).

Based on these evolving modeling techniques, facilitating the integration of renewables requires the full range of benefits of transmission to be considered in planning studies. Conventional planning methodologies in the integrated utility regime aimed at reliability as high as necessary and design as economical as possible (Schlabbach and Rofalski 2008; Stoll 1989). Economic efficiency benefits beyond production cost savings are also commonly analyzed, including the effect of transmission expansions on market prices, increased competition and market power mitigation (Awad et al. 2006; Sauma and Oren 2006). However, transmission expansion projects simultaneously offer a number of benefits (Joskow 2005), ranging from operational, to environmental and investment benefits. These benefits include enhanced reserve scheduling, alleviation of reliability-must-run dispatch, economic valuation of increased reliability, emissions benefits and fuel diversification (Inzunza 2014). While assessing these benefits is challenging, relying solely on easily quantifiable production cost savings would often lead to the rejection of otherwise beneficial investments (Hou and Pfeifenberger 2012).

Capital-intensive transmission projects of strategic value may seem sub-optimal if these additional benefits are dismissed. A practical example is the transmission interconnection project between the two Chilean power systems (Bustos-Salvagno and Fuentes 2017). Simple production cost analyses estimated net benefits between US$ 0.5 and US$ 1.5 bn (Synex–Mercados 2012), in net present value. Another wider economic assessment of the interconnection project assessed, among others, benefits of increased competition in the contracts market and resiliency against shocks (e.g., fuel disruption and project delays). Such wider economic assessment found benefits from the interconnection project between US$ 3.2 and US$ 9.1 bn, in addition to direct production cost benefits (Bustos-Salvagno and Fuentes 2017; CNE 2013). That is, the economic benefit of these additional assessments is a staggering 2–18 times higher than the benefits suggested by conventional planning studies. As mentioned in the introduction, the interconnection between both power systems was commissioned in November 2017 and ever since it has fostered competition (e.g., allowing generators in the south to compete for the supply of large mining companies) and reduced curtailment of renewable generation due to transmission congestion, among many other benefits.

A key trade-off in transmission planning is the desired level of transmission congestions versus acceptable levels of spare transmission capacity. Under expected future demand growth, spare transmission capacity results due to the fundamental properties of transmission infrastructure. Indeed, lumpy investments preclude small incremental investments for the required capacity in each moment, while economies of scale determine that it is better to build a little bigger to begin with, to accommodate future demand growth (Hirst and Kirby 2001). Therefore, there is a trade-off between congestion risks due to lack of adequate and timely expansions and the risks of capacity underutilization for far too long or even over-investment. Fast-growing economies such as Alberta and Chile tend to emphasize the need of robust planning transmission through spare capacities, to avoid the country-wide economic impacts of transmission congestion due to under-investment and delays. Moreover, the complete elimination of transmission congestions is pursued in some countries, despite it being a sub-optimal planning strategy (Stoft 2006). Alberta's transmission plan focused on achieving an unconstrained system until recent years (AESO 2014; Watts and Rudnick 2014). Transmission planning in Germany has also been historically guided by a copper plate standard aiming at unconstrained power markets, although the possibility of 3% renewable curtailment was introduced to the planning process in 2015 (Von Hirschhausen et al. 2018).

Spare capacity for robustness of transmission expansion plans was one of the key components of the Chilean transmission law. Transmission planning at the time was perceived to inadequately address uncertainty through scenarios of low diversity, short planning horizons and lack of strategic long-term vision. The authority argued that the regulation of the transmission planning process precluded enough spare capacity to be considered, thus resulting in prolonged transmission congestions, price decoupling within the power system and curtailment of renewable generation. Such spare capacity would be a key planning tool under uncertainty, given expectations for high demand growth and long lead times for new transmission projects. Much of the legislative discussion focused on the risks of over-investment due to speculative planning (Baldick and Kahn 1993). Although congress granted the regulator the ability to consider spare transmission capacities for future expected uses, implementation problems emerged relating primarily to the cost allocation reforms that were also introduced, as further discussed below.

When it comes to solutions, however, new wires are not everything. While spare capacities are needed for long-term planning, flexibility is paramount for short- and medium-term horizons. Flexibility can be defined as "*the ability to adapt the planned development of the transmission system, quickly and at a reasonable cost, to any change, foreseen or not, in the conditions that were considered at the time it was planned*" (Latorre et al. 2003). Flexibility encompasses many components of transmission planning, including the following:

- Optimization techniques for balancing robustness and flexibility of expansion plans under uncertainty (Mejia-Giraldo and McCalley 2014).
- Flexible solutions for addressing transmission needs, ranging from operational measures to non-wire investments. Flexible solutions require lower capital investment and lead times than new transmission lines, thus enabling deferral of transmission investments until uncertainty diminishes, as well as management of incremental variations in flow patterns in the meantime (e.g., due to quicker-than-expected completion of expected renewable projects). Solutions include optimization of the existing infrastructure through improved system operation (MIT 2011); repowering (Tejada et al. 2015); transmission switching (Fisher et al. 2008; Khodaei et al. 2010); dynamic line ratings (Douglass and Edris 1996; Fernandez et al. 2016); asset management (Brown and Humphrey 2005; Shahidehpour and Ferrero 2005); flexible equipment such as FACTS, phase shifters and storage (Blanco et al. 2011; Konstantelos and Strbac 2015) and other non-wire solutions such as demand response, energy efficiency and distributed generation solutions analyzed in California (CAISO 2013), Denmark (Weber et al. 2013) and UK (National Grid Plc 2014). Moreover, the proposition of additional solutions by independent project sponsors should be encouraged to foster innovation (Herling et al. 2016).
- Project management of planned capacity additions. More precisely, this includes timing of investments (Garcia et al. 2010), real options approach (Chamorro et al. 2012), decision trees (Buygi et al. 2003; RTE 2014) and staged project development to allow adaptation. Staged development should establish adaptability-enabling milestones for the complete expansion process, from conceptual design to spatial layout and permitting. For example, the UK TSO can recommend pre-construction studies to start outlining projects that could be necessary in the future. Moreover, projects under development can be postponed or even canceled in case of major changes in the market (National Grid Plc 2014).
- The flexibility of the process itself can be improved through higher frequency of the scenario and planning process (at least on a yearly basis for planning). Moreover, projects can be grouped in clusters of similar properties or complexities, to allow for expedited approval processes for the less controversial projects.

One illustrative example of plan flexibility pertains to the interaction of spare capacities and repowering. In its 2013–2014 transmission plan, the Chilean energy regulator (CNE) proposed a 500 kV line to supply the southernmost zone of the power system. A generation company presented a discrepancy against this project to the conflict resolution body of the Chilean power market, the Panel of Experts. The generator argued that the project should be developed in stages by deferring some branches and initially powering the line in 220 kV. In turn, the regulator's arguments included frustration with insufficient expansions from previous transmission planning processes and the need of a long-term vision for harnessing the wind generation potential in the southern zone. After careful analysis, in its Resolution N°3 of 2014, the Panel of Experts accepted the generators' proposal to develop the project in stages, notwithstanding the relative agreement regarding the long-term need of the project. This resolution made it clear that a wider variety of benefits and scenarios should be considered for these kinds of expansion projects to be feasible.

However, the lack of flexibility persisted as one of the weaknesses of the transmission process in Chile. Although the previously mentioned experience motivated profound and positive changes in the transmission law aiming at the long-term development of the market, medium-term transmission expansion was largely left unchanged. Crucially, the regulation did not establish the ability to postpone, modify or cancel complex expansion projects. In its 2017 expansion plan, the first under the recently enacted transmission law, the regulator proposed the biggest transmission project ever in Chile, a massive 1500 km/3000 MW HVDC transmission line with US$ 1.8 bn of referential investment. Such project would connect the north and center zones of the system, enabling the long-term development of solar generation in the north to supply growing demand in the center. Although the need of the project conveyed widespread agreement, the accelerated planning process with incomplete information and insufficient time for comments prompted a discrepancy to the Panel of Experts, this time by a mining company, arguably because the transmission law allocated expansion costs entirely to final customers (with no costs borne by generators). Panel's Resolution N° 7 of 2018 delayed the HVDC line to the 2018 plan for further analysis and specification. Unfortunately, given the inflexibilities of the process, this lengthy conflict resolution process also delayed by several months all the other expansion projects (many of which raised no opposition in the first place). In the 2018 planning process, the regulator finally achieved approval for a smaller 2000 MW HVDC line with US$ 1.3 bn of referential investment.

Given the importance, size and complexity of this HVDC project, staged development might be useful, particularly given the extreme difficulty that is expected from the overall siting process of this project (further discussed below). Moreover, the basic properties of the project are already defined, and the respective right-of-way shall be planned for the smaller approved project. This inflexibility precludes a later decision to build a higher capacity line which requires a wider strip of land, in case the renewable potential turns out to develop faster than expected. The need to incorporate more flexibility in the planning process has already been acknowledged by the authority and is a key part of a transmission planning improvement law currently being prepared by the Ministry.

2.3 Cost Allocation, Plan Approval and Project Development

Governance of the transmission approval and development process is pivotal to the success of the transmission expansion framework for renewable integration. After the optimal transmission network has been planned, such plan is subject to several stages of regulatory approval, administrative permitting and siting processes. Notwithstanding the need for careful planning, difficulties in the approval and development stages can result in severe delays, rerouting and redefinition of new transmission projects. Severe difficulties in this process can result in large opportunity losses for renewable generation and final customers due to curtailment and price decoupling. Moreover, inadequate processes undermine the confidence of new investors on the transmission expansion framework, slowing the pace of renewable generation investment.

A core issue in the transmission approval process is the trade-off between efficiency and simplicity of cost allocation methods. A beneficiaries-pay cost allocation methodology promotes market efficiency. However, application of a beneficiaries-pay rule is difficult for large-scale transmission projects with various benefits spread throughout wide geographic areas and different market participants (Hogan 2011). Socialization of transmission costs is relatively simple in practice, but would reduce the incentives for efficient expansion of the combined generation and transmission infrastructure.

Cost allocation in Chile for the main transmission grid (trunk grid) historically relied on a complex usage-based methodology. Congestion rents are assigned to Transcos, and transmission costs not covered by these congestion rents were shared among generators and loads. For the "common influence area" (defined by engineering criteria as the grid used by both generators and loads across the entire grid), 80% of the costs were allocated to generators and 20% to loads. Allocation between generators and between loads was based on approximate usage factors derived from simulations of the system's operation. Results were highly dependent on hydrological conditions, and the overall cost allocation framework was deemed too complex for new investors to understand and manage.

To facilitate and accelerate renewable investment, the Chilean transmission reform drastically simplified the transmission cost allocation method. After the law, costs of the trunk transmission grid (now called "national" grid) are allocated entirely to final customers through a simple postage stamp methodology. A 15-year transition period was established to gradually transfer transmission costs from generators to final customers for supply contracts signed before enactment of the law. Nonetheless, new generation projects would be automatically exempt from bearing transmission costs of the trunk grid (although generation interconnection costs are still borne by generators). These regulatory changes were expected to facilitate renewable investment by new investors, smaller than incumbent Gencos in Chile. Moreover, allocating costs of the trunk grid to final customers was consistent with the most common international practices (PJM 2010).

The simplification of cost allocation method means that locational and efficiency signals for investment were reduced (Matamala et al. 2019). Locational signals remain at the core of the Chilean market since the power pool still operates on short-run locational marginal prices. The lack of a locational signal in transmission cost allocation may in the long-term reduce the efficiency of the combined generation—transmission investment, incentivizing too much generation away from load centers. However, high-quality renewable resources cannot be transported to more convenient locations near demand centers. Thus, consensus emerged among participants of the transmission law discussion regarding the idea that locational signals in transmission cost allocation are meaningless for the transition to a highly renewable energy mix.

Allocating transmission costs directly to final customers was expected to increase transparency in final customer's bills. This would also reduce the risk premium that generators may be charging their customers due to the uncertainty embedded in transmission tolls, given their strong dependence on hydrological conditions. Indeed, supply contracts in Chile often pass through transmission costs to final customers. Thus, the argument goes, tolls should be directly allocated to final customers, since they end up paying for it anyway (Baldick et al. 2007).

This also increases the risk of overbuilding transmission if demand is too passive in the planning process, compared to generators. Historically, generators have been actively involved in the transmission planning process, arguably because the costs of new transmission projects would be mostly borne and managed by generators. Generators participation thus provided a market-based loop for transmission expansion efficiency. In turn, customers are often deemed to be less interested in the details of their electricity bill and the transmission planning process. However, Chilean experience suggests otherwise, since the new HVDC line planned by the authority was delayed and its capacity reduced due to opposition of large mining customers. Although such level of participation cannot be expected from residential customers, the conflict around the HVDC line highlights the need for final customer participation in early planning stages, with adequate time allowed to review and comment the expansion plan. Moreover, a benefit-based cost allocation procedure for new transmission projects could make issues and opposition to transmission expansion more transparent (Baldick et al. 2007).

After conflicts due to cost allocation are resolved and the expansion plan is approved, the complex permitting and siting process begins. Delays of major transmission expansion projects due to public opposition, permitting and siting processes can have significant impacts on the power market. These delays have proven very difficult to manage since they are largely locational specific, depending on the communities and administrative divisions involved. One related Chilean experience is the Cardones–Polpaico 2×500 kV line, which suffered a delay of 17 months with sizable economic impacts for renewable generators located in the northern zone (solar PV and wind). The delay was partly related to intense public opposition in the center zone, where electricity demand is concentrated. Rights-of-way negotiation was slow in the center zone given the large number of land owners. After negotiations finished, public opposition intensified with a few extreme acts that delayed completion of the last line segments. Public opposition to this transmission project emerged despite its need for renewable generation integration, which has more social support than the thermal generation that renewables replace.

Siting difficulties highlight the need for early stakeholder participation in transmission planning. Policy-makers and TSOs should acknowledge the large body of the literature addressing the underlying factors of public acceptance of new transmission projects, primarily the consensus that concerns of inhabitants and organized stakeholders go well beyond the Not-In-My-Backyard (NIMBY) phenomenon. Easily accessible information and a better representation of a project's impacts—beyond pure economics and cost-based analysis—are thus required (Devine-Wright 2012; Komendantova and Battaglini 2016a; Schmidt and Lilliestam 2015).

Further research is required to propose and compare participative solutions to the transmission siting conundrum (Cohen et al. 2014). Although participation and stakeholder empowerment from the need definition and spatial planning stages are ways of avoiding project delays, participation is project-tailored and does not automatically eliminate conflicts (Späth and Scolobig 2017). Participation is a dynamic process which requires optimal engagement time (not too late and not too early) and addressing new concerns that appear due to increased stakeholder awareness (Komendantova and Battaglini 2016b). While participation is a key means for social acceptance of new lines, some authors argue for participation to become a goal in itself. A siting approach based on an open dialog, with the possibility to co-decide and shape the project's definition, can foster societal acceptance of large interconnection projects (Ciupuliga and Cuppen 2013). Despite growing experience with transmission siting processes and practices around the world, much of the available literature is focused on European countries where one or a few TSOs plan and develop new transmission projects. In the Chilean framework, new transmission projects are planned by the authority and built by a transmission concessionaire. Other country-specific aspects make it difficult to successfully transfer lessons and best practices (Consorcio Centro Cambio Global UC—Centro de Energía U. de Chile y Teco Group 2018).

The Chilean transmission law introduced new instruments for spatial transmission planning and siting with a stronger role of the state as a "*guarantee of social welfare*". Before the law, new transmission projects were auctioned with little information on its route and awarded to the least-cost proposal (Ferreira et al. 2016). A broad consensus emerged in the public discussion of the transmission law, regarding the need of an increased role of the state in route definition of new transmission projects. In the new regime, the state formulates alternative strips with early public participation and a wider set of criteria beyond economic efficiency, including social and environmental sustainability. A strategic environmental assessment is developed in parallel to inform this strip study. The outcome of this process is a strip of land subject to approval by the Sustainability Council of Ministries. After the strip is approved, a public auction is conducted, and the awarded transmission concessionaire will be responsible for detailed route definition and project construction, as well as obtaining environmental and administrative permits (which also require public participation).

Despite broad consensus on the direction of these reforms, effective implementation will be crucial to success of the new transmission siting framework. Recent experiences suggest that new transmission lines will face intense public opposition if the siting process is not implemented effectively. The first strip study should start in 2020 for two tranches of a new 500 kV transmission system in the far-south zone of the Chilean grid, with an estimated length of 421 km. However, potentially conflictive projects will not be subject to this state-led process, given the authorities' criteria for determining project complexity. In fact, a 25 km line in the center-south zone will not be subject to a strip study, despite being more complex from a social–environmental perspective than one of the tranches of the 500-kV southern project. Given the Ministry's methodology, a strip study is not justified for the center-south project given its low technical complexity (in turn due to its low extension), despite its high social–environmental complexity. Hence, in practice, the transmission reform tackled the siting process for large transmission projects without addressing the siting process for smaller projects, which are often located near cities and communities (whereas large projects are often located farther from big cities). Siting of these small transmission projects will continue being managed by a variety of transmission concessionaires according to their own procedures for obtaining environmental and administrative permits.

Another potential weakness of the regulatory framework is the inability to plan a common strip for multiple transmission lines, nor for a possibly larger transmission line in the future. This flexibility is important, for example, for the planned HVDC between the center and northern zones required for scaling-up solar generation in the north. Seeking to ensure its approval, the authority adjusted the HVDC project by lowering its capacity and investment requirements below what was initially considered necessary. A strip study adjusted to the approved capacity will be conducted, probably precluding a larger project to be built in the future in case the approved capacity is later found to be too small to accommodate solar generation. Also, the strip cannot be wider than necessary to accommodate other transmission projects in the future. If poorly managed, this situation could result in two parallel HVDC projects which occupy a land strip much larger than necessary and which are developed in times much longer than necessary.

3 Reaching Out: Transmission for Harnessing Renewable Generation Hubs

Coordination of transmission and renewable generation investment is the key for market efficiency. Such coordination is especially challenging for renewable energy "hubs", or zones with a concentrated high-quality potential for renewable generation, for three reasons.

- First, renewable energy hubs can be located far from main demand centers or the transmission grid, thus requiring new dedicated transmission systems to cover widespread areas in order to harness the renewable potential.
- Second, renewable resources can be dispersed in large geographic areas, where independent connections designed for each possible generation project might be inefficiently costly, leading to less-than-optimal investment in renewable generation. Moreover, such independent connections can have significant socio-environmental impact, due to the multiplicity of transmission lines.
- Third, many smaller generation projects (i.e., less than 20 MW) are unable to finance investment in new dedicated transmission lines required to transport generation for large distances to the main transmission grid. Therefore, less projects than the efficient level would be developed due to the failure to coordinate and share the transmission costs among multiple developers.

Given these difficulties, anticipative and proactive transmission expansion approaches have been proposed. The anticipative approach would anticipate to the development of new generation projects to plan an optimized transmission network. A proactive planner would expand transmission considering the effect of these expansions on competing generators, seeking maximum efficiency by "guiding" generation investment through transmission investments.

Mixed outcomes have resulted from the implementation of these approaches to coordinate renewable generation investment in Texas, Brazil, Australia and recently Chile (Chattopadhyay 2011; Hasan et al. 2013; Madrigal and Stoft 2011; Porrua et al. 2009; Rudnick et al. 2012). The Texas experience with proactive transmission planning and staged coordination of new generation projects has been very successful, achieving integration of over 19 GW of wind generation and reducing curtailment to low, economic levels around 0.5% by 2014, down from 17% in 2009 (Billo 2017). The Brazilian experience with coordination of transmission for renewable projects that participate in supply auctions was also initially successful (Porrua et al. 2009). However, coordinated transmission expansion was later abandoned, partly due to transmission project delays and the difficulties of risk allocation between customers, planners and generators whose construction was uncertain (Bayer et al. 2018). Finally, to this date there have not been major successful experiences in Australia and Chile, despite their efforts to coordinate transmission for clusters or hubs of renewable generation.

However, many issues curb the development of coordinated transmission systems for renewable hubs. First, anticipative and proactive planning is by itself a challenging task, requiring new optimization methodologies and institutional arrangements compared to traditional planning. Second, planning transmission to incentivize optimal generation investment inevitably risks transmission asset stranding, in case some of the new generation projects get canceled. Third, the timing and development times of multiple generation firms can vary widely. Fourth, competing generation firms might be unwilling to trust their direct competitors with commercially sensitive information regarding their generation project portfolios. Moreover, generation firms might be wary of depending on the decisions of their direct competitors, let alone helping them achieve lower transmission costs and shorter time-to-market, since the potential competitive loss may outweigh transmission cost reductions due to coordination.

The coordination between transmission and generation investment for renewable energy hubs will be discussed in further detail below, by using simple examples to illustrate the underlying competitive and market forces. First, coordination between two similar generators by private initiative will be analyzed, highlighting the reasons that curb such private coordination (Sect. 3.1). Second, centralized coordination of transmission interconnection will be analyzed, highlighting the potential risks of such a solution (Sect. 3.2). Third, Sect. 3.3 overviews open access and its practical implications for renewable integration.

3.1 Voluntary Coordination of Two Similar Generators

Consider two similar new generation projects located nearby each other, but far from the main transmission grid (about 50 km). Suppose two alternative connection solutions are available, as depicted in Fig. 4. The first solution ("uncoordinated" solution) would leave the full development of transmission interconnection to generation developers, thus probably resulting in one dedicated interconnection transmission system for each generation project. Instead, the second solution ("coordinated" solution) would optimize the transmission interconnection system considering both generation projects, thus building a bigger common line and two smaller and independent interconnection lines.

The coordinated solution reaps the benefits of scale economies in transmission systems, thus achieving lower overall costs when compared to the uncoordinated interconnection solution. Using standard investment costs for the Chilean transmission systems, the example above would result in a total interconnection cost of MUS$ 24.5 in the uncoordinated solution (two independent transmission lines of MUS$ 12.3 each) and MUS$ 23.1 under a coordinated solution (composed of a common 15.4 MUS$ line and two independent lines that cost MUS$ 3.8 each). Thus, coordination would yield transmission interconnection savings for MUS$ 1.5, or about 6% of transmission interconnection costs, given the lower cost per MW of capacity for bigger transmission lines.

However, strategic considerations may deter a coordinated interconnection solution to be agreed upon and executed by the two generators. The first strategic concern is related to the increased risk that the potential cost saving implies. Consider the "payoff matrix" for both generators under the uncoordinated and coordinated solutions presented in Table 2, depicting the transmission interconnection costs borne by each generator (in each of the four columns), depending on the investment decision taken by the first generator (rows) and by the second generator (columns). In the uncoordinated solution, each generator would pay MUS$ 12.3 for transmission interconnection if (and when) it finally decides to invest, and would pay nothing otherwise.

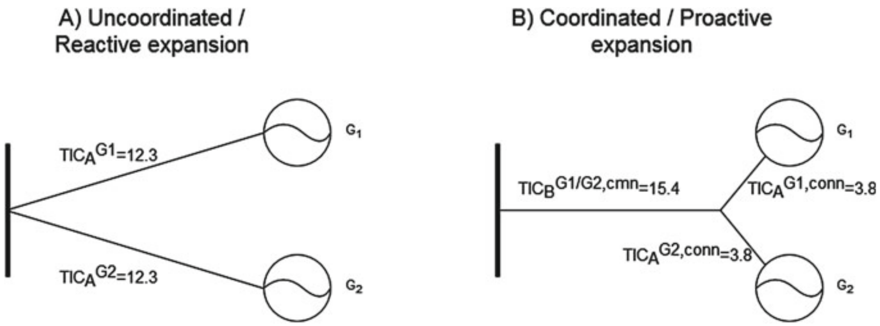

Fig. 4 Uncoordinated and coordinated transmission connection solutions

Table 2 Generators-game payoff matrix under both expansion alternatives

G1\G2	Invest		Not invest	
(A) Uncoordinated expansion				
Invest	−12.3	−12.3	−12.3	0
Not invest	0	−12.3	0	0
(B) Coordinated expansion				
Invest	−11.5	−11.5	−19.2	0
Not invest	0	−19.2	0	0

The outcome for each generator in the uncoordinated solution is independent of the other generator's investment decision and its timing.

In turn, the coordinated solution results in lower interconnection cost of MUS$ 11.5 for each generator, but only if both generators follow through with their pre-commitments to invest in a coordinated transmission interconnection project. However, consider that only G1 decides to invest in the coordinated system, but G2 decides not to participate of the coordinated system (whether because its project is canceled, or because it decides to develop an independent connection). Then G1 would bear the full cost of the common interconnection line (MUS$ 15.4), as well as its independent line (MUS$ 3.8), thus resulting in an interconnection cost of MUS$ 19.2, which is a MUS$ 7 loss with respect to the uncoordinated solution.

Considering that both generators invest in their respective power plants, but can either coordinate transmission or pursue an independent connection, the resulting game is an instance of the well-known stag hunt game (see Table 3). The stag hunt is a common example of coordination failures among individuals. Theoretically, this simple game has two pure Nash equilibrium strategies: both players coordinate or both fail to do so (Fudenberg and Tirole 1991). If both players coordinate, none of them has the incentive to unilaterally change their strategy, since payoffs would be lower. However, this is also true if both players do not coordinate.

Therefore, game theory does not predict a single pure strategy for rational players. In turn, the mixed strategy equilibrium (i.e., where each player has a probability distribution over his set of actions) depends on the probability of coordinating. For this example, coordinating would be better only if the probability that the other generator coordinates is over 90% (due to the large downside risk of building a larger than needed line). The probability of coordination required for it to be the optimal strategy needs to be higher with more players. In theoretical terms, the "both

Table 3 Generators-game payoff matrix if both invest in their power plant and choose whether or not to coordinate transmission

G1\G2	Coordinate	Not coordinate
Coordinate	−11.5, −11.5	−19.2, −12.3
Not coordinate	−12.3, −19.2	−12.3, −12.3

fail to coordinate" equilibrium is said to *risk-dominate* "both coordinate", despite coordination being *payoff dominant* over non-coordination (Harsanyi and Selten 1988).

Of course, if G2 withdraws from the coordinated system, G1 could drop the coordinated solution altogether and develop an independent interconnection instead. Then, the transmission cost of the coordinated solution is always lower than the coordinated expansion (the worst-case cost would be MUS$ 12.3 instead of MUS$ 19.2). Rational generators would thus pursue the coordinated solution first, and fall back to the uncoordinated option should coordination fail. Moreover, the credibility and feasibility of a coordinated solution may increase with enforceable contracts and the establishment of a special independent firm for developing the coordinated transmission project.

However, the risks of project delay can easily outweigh the benefits due to interconnection cost savings. Indeed, this optionality would require the transmission project to be postponed until enough certainty regarding the development of both generation projects is achieved.[2] Waiting for such certainty may significantly delay revenues from the generation project, since the other generator could fail in an advanced stage of project development. While the direct costs associated to the delay may be very small (e.g., restarting interconnection studies and permits), the opportunity costs could be tremendous due to foregone revenue from energy sales (especially if the generation project is committed for supplying a contract with final customers). Another option would be the parallel development of a coordinated and an uncoordinated solution. However, parallelism does not completely eliminate delay risks and would probably undermine confidence on the viability of the coordinated solution.

The importance of time-to-market over minor cost savings, and the properties of the strategic game between both generators described above, could well be enough to impede a coordinated solution to be pursued by competing generators in many real cases. However, other wider commercial considerations come at play against a coordinated solution. Attempting coordination would inevitably mean disclosing confidential information regarding the generator's project portfolio and commercial strategy. Moreover, the coordinated solution could ultimately improve the commercial position of a direct competitor and could thus be negative for a profit-maximizing generator. In the long-term, the portfolio-wide competitive loss due to a couple of additional competing renewable projects can be very small for large companies with several GWs of installed generation capacity. However, a few hundred MWs of additional renewable capacity can result in enormous short-term losses due to curtailment and price decoupling in constrained transmission networks such as the Chilean grid, further reducing incentives for a coordinated connection.

[2]A joint venture between the two generation firms could allow for full certainty by bundling the two generation projects as well as the common transmission system. However, that would not be a case of coordination among different firms. Moreover, joint ventures may be far less likely in zones with many generation projects (instead of only two).

For the reasons outlined above and given the relatively low level of potential cost savings due to coordination (when compared to total project costs and incomes), it seems rather unlikely that generators would voluntarily pursue a coordinated interconnection solution. It is worth noting that the issues with the coordinated interconnection (namely risks of projects' delay and slower time-to-market, risks of higher transmission costs, disclosing commercially sensitive information and helping a direct competitor) are also present in more general cases with multiple generation projects of different technologies and installed capacity. Indeed, while the potential cost savings of a coordinated solution could be higher for many small projects, the potential risks could also increase (with worse possible outcomes), as well as the difficulty of coordinating and establishing trust among many competing firms.

3.2 Centralized Coordination of Two Similar Generators

Transmission cost savings and cost sharing among multiple power plants can be key for developing new generation projects. Unlike thermal power plants, neither the wind nor the sun can be transported to a more convenient location. Given that high-quality renewable potential can be located far from the existing transmission networks, long transmission lines may be required to harness the full potential of the hub. In that case, the higher transmission cost associated to an uncoordinated solution can deter or even preclude altogether the development of some generation projects. The appeal of the coordinated interconnection solution is thus twofold: it lowers overall transmission costs, thus enabling more renewable potential to be harnessed.

Centralized coordination of transmission investment for facilitating renewable generation development is therefore an appealing policy. A coordinated transmission project would be designed, developed and executed with the state's direction. Renewable projects could then use the transmission capacity provided they pay their "fair share" for the coordinated system, so that an appropriate efficiency signal is preserved for the location and volume of renewable projects.

To illustrate the potential benefits of transmission coordination, assume, for the sake of simplicity, that two 200 MW solar PV power plants could be developed in a nearby location far from the main grid. Each power plant requires an investment of MUS$ 200 (consistent with public information of PV projects under development in Chile). Considering a capacity factor of 31% and an average spot price of 50 US$/MWh, each power plant would roughly save MUS$ 27.2 in total system operation costs on a yearly basis, or a present value of MUS$ 231.2 over a 20-year lifespan (with a 10% discount rate).

If coordination between both projects is implemented perfectly, coordination would yield savings of MUS$ 1.5 compared to the uncoordinated solution. However, should one of the projects fail to reach completion and pay for the common transmission infrastructure, the TSP would have to bear the stranded cost of the common line, equal to MUS$ 7.7 (see Table 4).

Table 4 Transmission interconnection costs with Transco-driven coordination

G1	G2	Transco (Tx)					
		Not invest			Invest		
		G1	G2	Tx	G1	G2	Tx
Invest	Invest	−11.5	−11.5	0	−11.5	−11.5	0
	Not invest	−19.2	0	0	−11.5	0	−7.7
Not invest	Invest	0	−19.2	0	0	−11.5	−7.7
	Not invest	0	0	0	0	0	−15.4

If excess costs due to stranded assets are not transferred away from the TSP and generators, and through to final customers or the state, it is unlikely that the coordinated solution is financed and executed. Indeed, if the TSP is allowed to increase charges to the completed generator, then prospective generators would refrain from participating in the coordinated solution, preferring an independent solution instead. If the TSP bears the risks of stranded assets, the project is unlikely to achieve financing due to the significant risks involved, which are not rewarded through higher expected returns.

However, transferring risks away from project developers could ultimately harm system efficiency. While facilitating the development of renewable projects through coordinated or proactive transmission can allow for increased investment in renewable generation, inefficient transmission or generation projects could end up developing at the cost of final customers.

As previously mentioned, centralized coordination could enable increased investment in generation projects which would otherwise be inviable. The benefit of higher and more efficient overall investment is far greater than the benefits due to transmission interconnection cost savings for large, high-quality generation projects which would be developed anyway (i.e., with or without coordination). The potential benefit related to guiding more efficient generation investments has been studied in the literature through proactive transmission planning models. Such models are formulated as sequential strategic games where the transmission planner has perfect information regarding the cost structure of individual generators, thus allowing the planner to determine optimal investment decisions for each generation firm, given the transmission expansion plan under assessment (Sauma and Oren 2006). While these assumptions could be adequate for the long-run planning of the overall transmission system, practitioners may find it difficult to determine optimal investment decisions for private generation firms in particular zones of the system.

Given the uncertainty involved in estimating generator's investment decisions, a probabilistic approach could be more adequate for analyzing the development of renewable hubs. The simplest approach is assuming that building a transmission system for a particular hub increases the probability of generation projects' completion. For example, based on the simple example presented above, consider that one generation project's completion (G1) is absolutely certain (i.e., with or without a coordinated transmission system), while the second-generation project's completion

(G2) is deemed uncertain. Further, assume that the planner estimates a 30% chance that G2 reaches completion if no coordinated system is developed. If a coordinated system is developed, lower interconnection costs would increase the probability that G2 is completed.

In this setting, building the coordinated system would only be beneficial (in expected present value) if the probability of G2's completion increases from 30% without coordination, to over 53%. Instead, if the probability is lower than 53% then, in expected present value, the planner would be better-off leaving transmission interconnection solely to generator developers. This sensitivity to perceived project completion likelihood highlights the risks involved in proactive transmission development for renewable generation hubs.

The general formulation of the related optimization problems would be as follows:

$$\min \sum_{l} \mathrm{CTIC}_l \cdot y_l + \sum_{g} E\left[\mathrm{GIC}_g + \mathrm{GTIC}_g + \mathrm{VC}_g | \{y_l\}_{\forall l}\right]$$

Subject to production, demand, transmission flows and variable nature constraints. Where

y_l	Binary decision variable for investment in coordinated transmission systems.
CTIC_l	Coordinated transmission investment costs, shared among coordinated generators.
GIC_g	Generation investment costs.
GTIC_g	Transmission interconnection costs borne by each generation firm.
VC_g	Total variable costs for each generator of the system.

The model presented above minimizes the total expected investment and operation costs, considering the impact that a centralized coordinated solution has on the likelihood of project completion. Unfortunately, the formulation above is nonlinear, since the probabilities required for calculating expected generation costs depend on the decision variables for coordinated transmission expansion. Nonetheless, for assessing rather small generation hubs, the problem can be solved by comparing the solutions with and without coordination, as depicted above.

The model captures the uncertainty associated with generation project development but fails to appropriately represent the underlying market forces in liberalized power markets, primarily, profit-maximizing generation firms. A more theoretically sound (albeit complicated) model could be posed as a Bayesian game where players (i.e., generators and the transmission planner) have uncertain information regarding the game itself (e.g., regarding the cost structure of each firm and generation project).

3.3 Open Access and Governance of the Transmission System

Open access to the transmission system is a core component of competitive power markets (Hogan 1998, 2002; Hunt 2002; Rudnick et al. 1997). Open access to the transmission grid means open access to dispatch, thus enabling short-run competition among generators and efficient transmission capacity allocation. Moreover, open access allows investment and the entry of new competitors through interconnection of new power plants.

Achieving effective open access in practice can be tricky. Investment in new renewable generation projects is particularly sensitive to the many components of the interconnection process and its regulation. Such components include cost allocation policies for new connections (deep vs. shallow), times and costs of the interconnection process, process standardization, governance and independence of the TSO/ISO, among others (Ellery et al. 2013; Madrigal and Stoft 2011).

For renewable generation in Chile, the scope of open access to dedicated transmission systems is particularly important. Dedicated systems are those that connect a single generation project or large customer to the main transmission grid. As explained above, the usage of the existing transmission lines located near high-quality renewable zones often poses significant benefits for small renewable power plants. These benefits are twofold. First, the power plant would bear lower interconnection costs, since it is usually cheaper to reinforce or expand existing transmission systems (although not always possible depending on the sizes of the new projects), rather than building a new transmission line. Second, the power plant would also face lower construction times and lower delay risks, since right-of-way and many other administrative permits are needed for shorter strips. Furthermore, there are many societal and environmental benefits since less transmission lines are built.

However, lacking appropriate institutions, new renewable project developers can find it hard to connect to these dedicated transmission systems. This was perceived to be the case in Chile by 2015, given the ownership structure and regulation of the transmission system. Transmission ownership in Chile is not solely allocated to a single or few transmission companies. Instead, transmission system ownership is dispersed among transmission, generation and distribution companies and even large customers (mostly mining companies). Furthermore, regulations for open access to dedicated transmission systems were not clear in many respects. Indeed, there was no bylaw regulation for dedicated systems, the regulation allowed some dedicated systems to be exempt from open access and there were no established procedures and referential costs for connection of new projects to different transmission systems.

If not standardized, connection procedures and costs can be discretionally set by the transmission system owner. This gives the owner the power to deter new connections by imposing high connection costs (whether through complicated and lengthy procedures and studies or through excessive tolls). The owner could be compelled to do so, for example, if he plans to develop new projects in the future making use of the existing system, if he wishes to deter entrance of new competitors (for generators) or if he simply wishes to avoid the trouble of multiple connections and toll agreements (for large customers such as mining or manufacturing companies, whose primary business is not electricity). Even if the transmission owner does not wish to deter new connections, different procedures and criteria for connection to each transmission system make it harder for new generators to enter the market.

The Chilean experience suggests that institutions for open access to dedicated transmission systems may need revisiting to allow for the efficient integration of renewable resources. Four lessons from the Chilean experience are outlined next. First of all, regulations must clarify the scope of open access. The best scenario for new renewable generators would be that every transmission system is subject to open access administered by the ISO. This was not the case in Chile, where the lack of open access to some dedicated systems did not seem to be a problem in the past, given the existence of only few market participants, who developed mostly large generation projects with dedicated transmission lines.

Second, the roles and functions regarding open access must be clarified and ideally allocated to a single entity (such as the ISO), provided other opportunities for dispute resolution (with the regulator or a dedicated expert entity, before leaving it to the courts). Connection procedures should be standardized across the power market administered by the ISO, independently of the owner of each individual transmission system. Such procedures should clearly specify the timing and general process for connection, including deadlines for yearly connection windows, in case connection applications are not received and processed all year long. Moreover, the process for determining and allocating Available Transfer Capacity (ATC) should be standardized and publicly available, and the process should also be administered by an independent ISO instead of individual market players, to avoid doubts regarding its fairness.

Third, the criteria applied by the ISO for approving new connections should be as transparent and standardized as possible, seeking to preserve reliability and system security above all, as well as fostering competition. For example, in Chile, the connection of new transmission systems to the main grid was not fully standardized. Procedures allowed for up to one tap-off connection to only one circuit of a transmission line in the main grid. However, when there were two or more connections to a single point of the main grid, new sectioning substations for all the circuits were required, with additional costs borne by the owner of the second or third connection. This standard made it far cheaper for the first-generation project to connect to the main grid. It also placed most of the financial burden of a secure connection on the second- or third-generation projects to connect to the main grid in a given location. With the advent of renewable generation, tap-offs quickly spread throughout the Chilean transmission grid and as of 2019 are still being replaced by fully functioning sectioning substations.

Fourth, property rights should be clearly allocated, and coordination thereof should be the responsibility of the ISO. In Chile, the transmission law and bylaws successfully clarified the scope of open access to electricity transmission infrastructure but failed to clarify property rights and open access to the communication lines bundled within power transmission lines. This led to some delays in the interconnection of new transmission projects and is therefore a key part of the refinement law currently under development by the Energy Ministry.

4 Conclusions

Timely and adequate transmission capacity is key for renewable energy integration. Short-run impacts for investors due to curtailment and market decoupling can be significant. However, the risks of overbuilding transmission should also be managed. A carefully designed and implemented framework for transmission expansion can support long-run efficiency and sustainability in the evolution of power systems. This chapter discussed some of the elements that could improve transmission planning, thus facilitating renewable integration.

A coordination problem between transmission and generation investments arises for harnessing hubs of high renewable potential. Small and geographically dispersed renewable projects could benefit from economies of scale stemming from coordinated transmission expansions. However, economic risks and strategic considerations curb the development of such coordinated transmission solutions. The Texas experience with proactive coordination of wind farms is a major success of transmission–generation coordination for efficient wind farm accommodation. However, mixed experiences have emerged in Brazil, Chile and Australia, given the difficulties associated to planning, coordination and allocation of the costs and risks of proactive transmission investments. Further research and analyses are needed to shed lights on possible solutions to the coordination conundrum. These solutions should aim both at economic efficiency and practical feasibility.

Regarding planning studies, practitioners should resort to the wide variety of optimization models developed to support transmission planning. Quantitative modeling should be a core component of the transmission planning process. Although many optimization models are computationally challenging to solve, incremental improvements of transmission planning modeling should be continually pursued by practitioners. For example, planning could be improved by modeling the temporal and spatial correlation of renewable resources, as well as flexible expansion alternatives such as FACTS and storage. Practitioners should also consider general policy recommendations stemming from sophisticate models which may be difficult to solve directly for real case studies. For example, competitive benefits of transmission should be considered at least approximately, given that competitive equilibrium models might be difficult to calibrate and solve in practice.

The whole process of transmission expansion deals with various uncertainties and complexities due to multiple conflicting criteria. Primarily, quantitative techniques guide the planning process in the short- to medium-term. Mostly, qualitative participatory processes for generating long-term scenarios have emerged worldwide as a primary tool to model and communicate more complex uncertainties. In any case, optimization approaches should be used more often by practitioners to determine the optimal expansion plan. Although academic research has made tremendous advances, many planners rely on simple heuristics for selecting "optimal" projects, not relying on optimization techniques such as stochastic programming, robust optimization and multi-objective optimization. In particular, tremendous uncertainty on the future location and technological mix of renewable generation calls for increased reliance on optimization techniques to guide the transmission planning decision-making process. A simple example is provided by Chile, where both the solar potential of the north and the wind and hydro-potential of the south could develop in the future. The decision of building lines from the center (where demand is concentrated) to the north or to the south ultimately depends on both the qualitative visions regarding plausible futures and the optimality of the expansion plan under various kinds of uncertainties and multiple criteria.

Long-run reliability, efficiency and sustainability of the power sector require a holistic approach to transmission expansion. In this sense, the most complex process within transmission planning is the approval and siting of new overhead transmission lines. Lack of early and effective participation of communities and stakeholders in the decision-making process increases the risks of later delays due to opposition, judicialization and even redefinition of the projects. Transmission siting and therefore the whole expansion process are shaped by a confluence of regulation, technical–economic theory, underlying market fundamentals, social and environmental dynamics and ultimately good governance and institutional capacity to ensure the practical effectiveness of the transmission expansion framework. Convergence of approaches and analyses from all these disciplines is required to facilitate a smooth transition towards the much-needed low-carbon economies of the future.

References

AESO, *AESO 2013 Long-term Transmission Plan* (2014)

M. Awad, S. Broad, K.E. Casey, A.S. Geevarghese, J.C. Miller, A.J. Perez, et al., The California ISO transmission economic assessment methodology (TEAM): principles and application to Path 26. *2006 IEEE Power Engineering Society General Meeting*, 8 p (2006). https://doi.org/10.1109/PES.2006.1709178

R. Baldick, A. Brown, J. Bushnell, S. Tierney, T. Winter, *A national Perspective: On Allocating the Costs of New Transmission Investment: Practice and Principles* (2007). Retrieved from https://hepg.hks.harvard.edu/files/hepg/files/rapp_5-07_v4.pdf

R. Baldick, E. Kahn, Network costs and the regulation of wholesale competition in electric power. J. Regul. Econ. **5**(4), 367–384 (1993). https://doi.org/10.1007/BF01065403

B. Bayer, L. Berthold, B.M.R. de Freitas, The Brazilian experience with auctions for wind power: an assessment of project delays and potential mitigation measures. Energy Policy **122**, 97–117 (2018). https://doi.org/10.1016/j.enpol.2018.07.004

J. Billo, *The Texas Competitive Renewable Energy Zone Process* (2017). Retrieved from https://cleanenergysolutions.org/sites/default/files/documents/jeff-billo_webinar-ercot-crez-process.pdf

G. Blanco, F. Olsina, F. Garces, C. Rehtanz, Real option valuation of FACTS investments based on the least square Monte Carlo method. IEEE Trans. Power Syst. **26**(3), 1389–1398 (2011). https://doi.org/10.1109/TPWRS.2010.2094211

L. Börjeson, M. Höjer, K.-H. Dreborg, T. Ekvall, G. Finnveden, Scenario types and techniques: towards a user's guide. Futures **38**(7), 723–739 (2006). https://doi.org/10.1016/j.futures.2005.12.002

BP, *BP Statistical Review of World Energy 2019* (2019). https://doi.org/10.2307/3324639

R. Bradfield, G. Wright, G. Burt, G. Cairns, K. Van Der Heijden, The origins and evolution of scenario techniques in long range business planning. Futures **37**(8), 795–812 (2005). https://doi.org/10.1016/j.futures.2005.01.003

R.E. Brown, B.G. Humphrey, Asset management for transmission and distribution. IEEE Power Energ. Mag. **3**(3), 39–45 (2005). https://doi.org/10.1109/MPAE.2005.1436499

E. Bustamante-Cedeño, S. Arora, Stochastic and minimum regret formulations for transmission network expansion planning under uncertainties. J. Oper. Res. Soc. **59**(11), 1547–1556 (2008). Retrieved from http://www.jstor.org/stable/20202237

J. Bustos-Salvagno, F. Fuentes, Electricity interconnection in Chile: prices versus costs. Energies **10**(9), 1438 (2017). https://doi.org/10.3390/en10091438

M.O. Buygi, G. Balzer, H.M. Shanechi, M. Shahidehpour, Market-based transmission expansion planning. IEEE Trans. Power Syst. **19**(4), 2060–2067 (2004). https://doi.org/10.1109/TPWRS.2004.836252

M.O. Buygi, H.M. Shanechi, G. Balzer, M. Shahidehpour, Transmission planning approaches in restructured power systems, in *Power Tech Conference Proceedings, 2003 IEEE Bologna*, p. 7, vol. 2 (2003). https://doi.org/10.1109/PTC.2003.1304666

M.O. Buygi, H.M. Shanechi, G. Balzer, M. Shahidehpour, N. Pariz, Network planning in unbundled power systems. IEEE Trans. Power Syst. **21**(3), 1379–1387 (2006). https://doi.org/10.1109/TPWRS.2006.873016

CAISO, *Consideration of Alternatives to Transmission or Conventional Generation to Address Local Needs in the Transmission Planning Process* (2013). Retrieved from https://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf

J.M. Chamorro, L.M. Abadie, R. de Neufville, M. Ilic, Market-based valuation of transmission network expansion. A heuristic application in GB. Energy **44**(1), 302–320 (2012). https://doi.org/10.1016/j.energy.2012.06.028

D. Chattopadhyay, Scale efficient network development to support renewable generation development. IEEE Trans. Sustainab. Energy **2**(3), 329–339 (2011). https://doi.org/10.1109/TSTE.2011.2138173

A.R. Ciupuliga, E. Cuppen, The role of dialogue in fostering acceptance of transmission lines: the case of a France-Spain interconnection project. Energy Policy **60**, 224–233 (2013). https://doi.org/10.1016/J.ENPOL.2013.05.028

CNE, *Impacto Económico y Social de Interconexión SIC-SING* (2013). Retrieved from https://www.cne.cl/wp-content/uploads/2015/07/Impacto-Económico-y-Social-de-Interconexión-SIC-SING.pdf

J.J. Cohen, J. Reichl, M. Schmidthaler, Re-focussing research efforts on the public acceptance of energy infrastructure: a critical review. Energy **76**, 4–9 (2014). https://doi.org/10.1016/J.ENERGY.2013.12.056

Consorcio Centro Cambio Global UC—Centro de Energía U. de Chile y Teco Group, *Estudio para la Implementación del Proceso de Determinación de Franjas Preliminares* (2018). Retrieved from http://franjas.minenergia.cl/sites/default/files/estudio_para_la_implementacion_del_proceso_de_determinacion_de_franjas_preliminares.pdf

P. Devine-Wright, Explaining "NIMBY" objections to a power line: the role of personal, place attachment and project-related factors. Environ. Behav. **45**(6), 761–781 (2012). https://doi.org/10.1177/0013916512440435

F.X. Diebold, N.A. Doherty, R.J. Herring, Introduction, in *The Known, the Unknown, and the Unknowable in Financial Risk Management: Measurement and Theory Advancing Practice*, ed. by F.X. Diebold, N.A. Doherty, R.J. Herring (2010), pp. 1–30. Retrieved from http://www.jstor.org/stable/j.cttq9s3f.4

J. Dillon, D.J. Burke, M.J. O'Malley, A. Tuohy, Should unit commitment be endogenously included in wind power transmission planning optimisation models? IET Renew. Power Gener. **8**(2), 132–140 (2014). https://doi.org/10.1049/iet-rpg.2011.0272

D.A. Douglass, A.-A. Edris, Real-time monitoring and dynamic thermal rating of power transmission circuits. IEEE Trans. Power Delivery **11**(3), 1407–1418 (1996). https://doi.org/10.1109/61.517499

E. Ela, M. Milligan, A. Bloom, A. Botterud, A. Townsend, T. Levin, *Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Generation* (2014)

E. Ellery, A. Brown, E. Crousillat, AF-Mercados EMI, V. Loksha, R. Tan, B. Dilli, *International Experience with Open Access to Power Grids: Synthesis Report* (2013), pp. 1–56. Retrieved from http://documents.worldbank.org/curated/en/2013/11/18699545/international-experience-open-access-power-grids-synthesis-report

Energy Ministry, *Proceso de planificación energética de largo plazo* (2017). Retrieved from http://pelp.minenergia.cl/files/100

ENTSO, *TYNDP 2018: Scenario Report* (2018). Retrieved from https://docstore.entsoe.eu/Documents/TYNDP documents/TYNDP2018/Scenario_Report_2018_Final.pdf

E. Fernandez, I. Albizu, M.T. Bedialauneta, A.J. Mazon, P.T. Leite, Review of dynamic line rating systems for wind power integration. Renew. Sustain. Energy Rev. **53**, 80–92 (2016). https://doi.org/10.1016/J.RSER.2015.07.149

R. Ferreira, H. Rudnick, L. Barroso, The expansion of transmission—the challenges faced in South America. IEEE Power Energy Mag. **14**(4) (2016). Retrieved from http://ieeexplore.ieee.org/document/7491387/

E.B. Fisher, R.P. O'Neill, M.C. Ferris, Optimal transmission switching. IEEE Trans. Power Syst. **23**(3), 1346–1355 (2008). https://doi.org/10.1109/TPWRS.2008.922256

D. Fudenberg, J. Tirole, *Game theory* (The MIT Press, Cambridge, 1991)

R.C. Garcia, J. Contreras, P.F. Correia, J.I. Munoz, Transmission assets investment timing using net present value curves. Energy Policy **38**(1), 598–605 (2010). https://doi.org/10.1016/j.enpol.2009.10.012

R.E. Gomory, The known, the unknown and the unknowable, in *Scientific American* (1995). Retrieved from http://www.scientificamerican.com/article/the-known-the-unknown-and-the-unkno/

B.G. Gorenstin, N.M. Campodonico, J.P. Costa, M.V.F. Pereira, Power system expansion planning under uncertainty. IEEE Trans. Power Syst. **8**(1), 129–136 (1993). https://doi.org/10.1109/59.221258

Y. Gu, J. McCalley, Market-based transmission expansion planning under uncertainty. North Am. Power Sym. (NAPS) **2010**, 1–6 (2010). https://doi.org/10.1109/NAPS.2010.5619975

J.C. Harsanyi, R. Selten, *A General Theory of Equilibrium Selection in Games* (MIT Press, Cambridge, 1988)

K.N. Hasan, T.K. Saha, M. Eghbal, D. Chattopadhyay, Review of transmission schemes and case studies for renewable power integration into the remote grid. Renew. Sustain. Energy Rev. **18**, 568–582 (2013). https://doi.org/10.1016/j.rser.2012.10.045

S. Herling, F. Koza, P. McGlynn, The sponsorship model: competitive construction of transmission facilities in PJM interconnection. IEEE Power Energy Mag. **14**(4) (2016)

E. Hirst, B. Kirby, Key transmission planning issues. Electr. J. **14**(8), 59–70 (2001). https://doi.org/10.1016/S1040-6190(01)00239-1

W.W. Hogan, *Competitive Electricity Markets: A Wholesale Primer* (1998). Retrieved from http://www.hks.harvard.edu/fs/whogan/empr1298.pdf

W.W. Hogan, Electricity Market Restructuring: Reforms of Reforms. J. Regul. Econ. **21**(1), 103–132 (2002). https://doi.org/10.1023/A:1013682825693

W.W. Hogan, *Transmission Benefits and Cost Allocation* (2011). Retrieved from http://www.hks.harvard.edu/fs/whogan/Hogan_Trans_Cost_053111.pdf

H. Holttinen, A. Tuohy, M. Milligan, E. Lannoye, V. Silva, S. Muller, L. Soder, The flexibility workout: managing variable resources and assessing the need for power system modification. IEEE Power Energ. Mag. **11**(6), 53–62 (2013). https://doi.org/10.1109/MPE.2013.2278000

D. Hou, J.P. Pfeifenberger, Transmission's true value: adding up the benefits of infrastructure investments. Public Utilities Fortn. **7** (2012). Retrieved from http://westpointproject.com/wp-content/uploads/2010/10/Transmissions-True-Value2.pdf

S. Hunt, *Making Competition Work in Electricity* (Wiley, New York, 2002)

IEA, *Renewables 2018: Executive Summary* (2018). Retrieved from https://webstore.iea.org/download/summary/2312?fileName=English-Renewables-2018-ES.pdf

Inzunza, A., *CVAR Constrained Planning of Renewable Generation with Consideration of System Inertial Response, Reserve Services and Demand Participation* (Pontificia Universidad Católica de Chile, 2014). Retrieved from http://web.ing.puc.cl/~power/paperspdf/AndresInzunza.pdf

IPCC, *Emissions Scenarios* (2000). Retrieved from https://www.ipcc.ch/site/assets/uploads/2018/03/emissions_scenarios-1.pdf

IPCC, Summary for policymakers, in *Global Warming of 1.5°C. An IPCC Special Report on the Impacts of Global Warming of 1.5°C Above Pre-industrial Levels and Related Global Greenhouse Gas Emission Pathways, in the Context of Strengthening the Global Response to the Threat of Climate Change* ed. by V. Masson-Delmotte, P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, et al. (2018), p. 32. Retrieved from https://www.ipcc.ch/site/assets/uploads/sites/2/2019/05/SR15_SPM_version_report_LR.pdf

S. Jin, A. Botterud, S.M. Ryan, Temporal versus Stochastic Granularity in thermal generation capacity planning with wind power. IEEE Trans. Power Syst. **29**(5), 2033–2041 (2014). https://doi.org/10.1109/TPWRS.2014.2299760

P.L. Joskow, *Patterns of Transmission Investment* (2005). Retrieved from http://economics.mit.edu/files/1174

G. Kavlak, J. McNerney, J.E. Trancik, Evaluating the causes of cost reduction in photovoltaic modules. Energy Policy **123**, 700–710 (2018). https://doi.org/10.1016/J.ENPOL.2018.08.015

A. Khodaei, M. Shahidehpour, S. Kamalinia, Transmission switching in expansion planning. IEEE Trans. Power Syst. **25**(3), 1722–1733 (2010). https://doi.org/10.1109/TPWRS.2009.2039946

D. Kirschen, G. Strbac, *Fundamentals of Power System Economics* (2005). Wiley, New York

N. Komendantova, A. Battaglini, Beyond Decide-Announce-Defend (DAD) and Not-in-My-Backyard (NIMBY) models? Addressing the social and public acceptance of electric transmission lines in Germany. Energy Res. Soc. Sci. **22**, 224–231 (2016a). https://doi.org/10.1016/J.ERSS.2016.10.001

N. Komendantova, A. Battaglini, Social challenges of electricity transmission: grid deployment in Germany, the United Kingdom, and Belgium. IEEE Power Energ. Mag. **14**(4), 79–87 (2016b). https://doi.org/10.1109/MPE.2016.2550399

I. Konstantelos, G. Strbac, Valuation of flexible transmission investment options under uncertainty. IEEE Trans. Power Syst. **30**(2), 1047–1055 (2015). https://doi.org/10.1109/TPWRS.2014.2363364

G. Latorre, R.D. Cruz, J.M. Areiza, A. Villegas, Classification of publications and models on transmission expansion planning. IEEE Trans. Power Syst. **18**(2), 938–946 (2003). https://doi.org/10.1109/TPWRS.2003.811168

P. Linares, Multiple criteria decision making and risk analysis as risk management tools for power systems planning. IEEE Trans. Power Syst. **17**(3), 895–900 (2002). https://doi.org/10.1109/TPWRS.2002.800991

M. Madrigal, S. Stoft, *Transmission Expansion for Renewable Energy Scale-Up Emerging Lessons and Recommendations* (2011). Retrieved from http://siteresources.worldbank.org/EXTENERGY2/Resources/Transmission-Expansion-and-RE.pdf

C. Matamala, R. Moreno, E. Sauma, The value of network investment coordination to reduce environmental externalities when integrating renewables: case on the Chilean transmission network. *Energy Policy* **126**(October 2018), 251–263 (2019). https://doi.org/10.1016/j.enpol.2018.10.065

D. Mejia-Giraldo, J.D. McCalley, Maximizing future flexibility in electric generation portfolios. IEEE Trans. Power Syst. **29**(1), 279–288 (2014). https://doi.org/10.1109/TPWRS.2013.2280840

M. Milligan, B.A. Frew, A. Bloom, E. Ela, A. Botterud, A. Townsend, T. Levin, Wholesale electricity market design with increasing levels of renewable generation: revenue sufficiency and long-term reliability. Electr. J. **29**(2), 26–38 (2016). https://doi.org/10.1016/j.tej.2016.02.005

MIT. *The Future of the Electric Grid* (2011). Retrieved from http://mitei.mit.edu/system/files/Electric_Grid_Full_Report.pdf

A. Moreira, G. Strbac, R. Moreno, A. Street, I. Konstantelos, A five-level MILP model for flexible transmission network planning under uncertainty: a min–max regret approach. IEEE Trans. Power Syst. **33**(1), 486–501 (2018). https://doi.org/10.1109/TPWRS.2017.2710637

R. Moreno, D. Pudjianto, G. Strbac, Transmission network investment with probabilistic security and corrective control. IEEE Trans. Power Syst. **28**(4), 3935–3944 (2013). https://doi.org/10.1109/TPWRS.2013.2257885

C. Munoz, E. Sauma, J. Contreras, J. Aguado, D. La Torre, Impact of high wind power penetration on transmission network expansion planning. IET Gener. Transm. Distrib. **6**(12), 1281–1291 (2012). https://doi.org/10.1049/iet-gtd.2011.0552

F.D. Munoz, B.F. Hobbs, J.L. Ho, S. Kasina, An engineering-economic approach to transmission planning under market and regulatory uncertainties: WECC case study. IEEE Trans. Power Syst. **29**(1), 307–317 (2014). https://doi.org/10.1109/TPWRS.2013.2279654

F.D. Munoz, J.-P. Watson, B.F. Hobbs, Optimizing your options: extracting the full economic value of transmission when planning under uncertainty. Electr. J. **28**(5), 26–38 (2015). https://doi.org/10.1016/j.tej.2015.05.002

D. Myers, A. Kitsuse, Constructing the future in planning: a survey of theories and tools. J. Plan. Educ. Res. **19**(3), 221–231 (2000). https://doi.org/10.1177/0739456X0001900301

National Grid, *Electricity Ten Year Statement 2015* (2015a). Retrieved from http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-Ten-Year-Statement/

National Grid, *Future Energy Scenarios 2015* (2015b). Retrieved from http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=41952

National Grid Plc, *Electricity Ten Year Statement 2014* (2014). Retrieved from https://www.nationalgrideso.com/document/46941/download

K. Neuhoff, J. Barquin, J.W. Bialek, R. Boyd, C.J. Dent, F. Echavarren et al., Renewable electric energy integration: quantifying the value of design of markets for international transmission capacity. Energy Econ. **40**, 760–772 (2013). https://doi.org/10.1016/j.eneco.2013.09.004

G.C. Oliveira, S. Binato, M.V.F. Pereira, Value-based transmission expansion planning of hydrothermal systems under uncertainty. IEEE Trans. Power Syst. **22**(4), 1429–1435 (2007). https://doi.org/10.1109/TPWRS.2007.907161

G.A. Orfanos, P.S. Georgilakis, N.D. Hatziargyriou, Transmission expansion planning of systems with increasing wind power integration. IEEE Trans. Power Syst. **28**(2), 1355–1362 (2013). https://doi.org/10.1109/TPWRS.2012.2214242

R. Pérez Odeh, D. Watts, Impacts of wind and solar spatial diversification on its market value: a case study of the Chilean electricity market. Renew. Sustain. Energy Rev. **111**, 442–461 (2019). https://doi.org/10.1016/J.RSER.2019.01.015

PJM, *A Survey of Transmission Cost Allocation Issues, Methods and Practices* (2010). Retrieved from https://core.ac.uk/download/pdf/21721132.pdf

PJM, *2014 Regional Transmission Expansion Plan Report—Book 1 RTEP in Review* (2015a). Retrieved from http://www.pjm.com/~/media/documents/reports/2014-rtep/2014-rtep-book-1.ashx

PJM, *2014 Regional Transmission Expansion Plan Report—Scenario and Interregional Study Results* (2015b). Retrieved from http://pjm.com/~/media/documents/reports/2014-rtep/2014-rtep-book-4.ashx

PJM, *2017 RTEP Process Scope and Input Assumptions* (2017). Retrieved from https://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en

F. Porrua, R. Chabar, L.M. Thome, L.A. Barroso, M. Pereira, Incorporating large-scale renewable to the transmission grid: technical and regulatory issues. IEEE Power Energy Soc. Gen. Meet. **2009**, 1–7 (2009). https://doi.org/10.1109/PES.2009.5275657

RTE, *Schéma décennal de développement du réseau Édition 2014* (2014). Retrieved from https://www.rte-france.com/sites/default/files/sddr_2014.pdf

H. Rudnick, L.A. Barroso, D. Llarens, D. Watts, R. Ferreira, Flexible connections: solutions and challenges for the integration of renewables in South America. IEEE Power Energ. Mag. **10**(2), 24–36 (2012). https://doi.org/10.1109/MPE.2011.2178300

H. Rudnick, R. Varela, W. Hogan, Evaluation of alternatives for power system coordination and pooling in a competitive environment. IEEE Trans. Power Syst. **12**(2), 605–613 (1997). https://doi.org/10.1109/59.589615

G. Sanchis, B. Betraoui, T. Anderski, E. Peirano, R. Pestana, B. De Clercq et al., The corridors of power: a Pan-European, "Electricity Highway" system for 2050. IEEE Power Energ. Mag. **13**(1), 38–51 (2015). https://doi.org/10.1109/MPE.2014.2363528

E. Sauma, S. Oren, Proactive planning and valuation of transmission investments in restructured electricity markets. J. Regul. Econ. **30**(3), 358–387 (2006). Retrieved from http://econpapers.repec.org/RePEc:kap:regeco:v:30:y:2006:i:3:p:358–387

J. Schlabbach (Jürgen), K.-H. Rofalski, *Power System Engineering: Planning, Design, and Operation of Power Systems and Equipment* (Wiley-VCH, Weinheim, 2008)

P. Schmidt, J. Lilliestam, Reducing or fostering public opposition? A critical reflection on the neutrality of pan-European cost–benefit analysis in electricity transmission planning. Energy Res. Soc. Sci. **10**, 114–122 (2015). https://doi.org/10.1016/j.erss.2015.07.003

P.J.H. Schoemaker, Multiple scenario development: its conceptual and behavioral foundation. Strateg. Manag. J. **14**(3), 193–213 (1993). https://doi.org/10.1002/smj.4250140304

M. Shahidehpour, R. Ferrero, Time management for assets: chronological strategies for power system asset management. IEEE Power Energ. Mag. **3**(3), 32–38 (2005). https://doi.org/10.1109/MPAE.2005.1436498

L. Späth, A. Scolobig, Stakeholder empowerment through participatory planning practices: the case of electricity transmission lines in France and Norway. Energy Res. Soc. Sci. **23**, 189–198 (2017). https://doi.org/10.1016/J.ERSS.2016.10.002

S. Stoft, Transmission investment in a deregulated power market, in *Competitive Electricity Markets and Sustainability*, ed. by F. Lévêque (2006), p. 34. Retrieved from http://stoft.com/metaPage/lib/Stoft-2005-07-Tx-Invest-EU-final.pdf

H.G. Stoll, *Least-Cost Electric Utility Planning* (Wiley-Interscience, New York, 1989)

Synex–Mercados. *Análisis Técnico y Económico de una Interconexión SING–SIC* (2012). Retrieved from https://www.cne.cl/wp-content/uploads/2015/07/Informe-Final-Interconexión-Sing-Sic.pdf

D. Tejada, J. Lopez-Lezama, M.J. Rider, G. Vinasco, Transmission network expansion planning considering repowering and reconfiguration. Int. J. Electr. Power Energy Syst. **69**, 213–221 (2015). https://doi.org/10.1016/j.ijepes.2015.01.008

A. Tversky, D. Kahneman, Judgment under uncertainty: heuristics and biases. Science **185**(4157), 1124–1131 (1974). Retrieved from http://www.jstor.org/stable/1738360

A.H. van der Weijde, B.F. Hobbs, The economics of planning electricity transmission to accommodate renewables: using two-stage optimisation to evaluate flexibility and the cost of disregarding uncertainty. Energy Econ. **34**(6), 2089–2101 (2012). https://doi.org/10.1016/j.eneco.2012.02.015

P.W. van Notten, J. Rotmans, M.B. van Asselt, D.S. Rothman, An updated scenario typology. Futures **35**(5), 423–443 (2003). https://doi.org/10.1016/S0016-3287(02)00090-3

C. Velásquez, *Robust and Efficient Decision Making for Transmission Expansion Planning Under Uncertainty* (2017). Retrieved from http://hrudnick.sitios.ing.uc.cl/paperspdf/ConstantinVelasquez.pdf

C. Velasquez, D. Watts, H. Rudnick, C. Bustos, A framework for transmission expansion planning: a complex problem clouded by uncertainty. IEEE Power Energy Mag. **14**(4) (2016). https://doi.org/10.1109/MPE.2016.2547278

C. Von Hirschhausen, C. Gerbaulet, C. Kemfert, C. Lorenz, P.-Y. Oei, *Energiewende "Made in Germany": Low Carbon Electricity Sector Reform in the European Context* (Springer, Cham, 2018)

D. Watts, N. Oses, R. Pérez, Assessment of wind energy potential in Chile: a project-based regional wind supply function approach. Renew. Energy **96**, 738–755 (2016). https://doi.org/10.1016/j.renene.2016.05.038

D. Watts, H. Rudnick, *Expansión de la Transmisión Informe Final* (2014)

A. Weber, T. Beckers, P. Behr, N. Bieschke, S. Fehner, C. von Hirschhausen, *Long-term Power System Planning in the Context of Changing Policy Objectives—Conceptual Issues and Selected Evidence from Europe* (2013). Retrieved from http://www.sefep.eu/activities/publications-1/SEFEP_gridplanning_June2013.pdf