REPORT on

Renewable Energy and Distributed Generation:

International Case Studies on Technical and Economic Considerations

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Executive summary

This report compiles international case studies, each addressing different technical and economic challenges related to renewable energy generation and detailing the approaches taken by individual countries. Between them the case studies address six broad themes, set out below.

Chapter 1 addresses the issue of connecting renewable energy to the grid, particularly where the generation takes place in remote locations and therefore requires significant investment. In Ontario the Energy Board's reformed regulatory instruments, designed to enable the government's objectives on renewable energy, have led to a high uptake of feed-in tariffs (FITs), a refined connection process and plan, and a system of sharing the costs of connecting renewable generation to the grid among ratepayers. Australia's approach to cross-company cooperation demonstrates the advantages of economies of scale, and reveals several possible solutions to the obstacles to collaboration. This suggests that a broad range of measures is necessary to fully enable the connection of renewable energy to the grid. However, it also demonstrates that the individual situation of each participating company can create barriers to cooperative efforts.

Chapter 2 discusses the impact of wholesale market and system operator arrangements on renewable energy generation. In New England, market allowances have been made for the particular characteristics of renewable generation and are allowing the systems to develop. Also in the USA, the Federal Energy Regulatory Commission has proposed changes to organised energy markets in order to better integrate increasing levels of renewable generation. Energy markets are currently fragmented across national borders in Europe. Steps are being taken to create a single market with the aim of allowing more efficient use of renewable energy sources. There are also problems in the form of early capacity allocation, which does not allow for the characteristics of intermittent renewable sources, as well as a lack of physical interconnection and incompatible regulatory systems between Member States.

Chapter 3 assesses the impact of renewable energy generation on conventional generation due to differing system requirements, particularly with regards to intermittency. In Europe there has been a focus on what this means for the provision of back-up generation capacity, with differing approaches taken by various Member States including: the establishment of capacity markets and payments, the exploration of electricity storage, and the construction of flexible reserve plants. In the USA, the Bonneville Power Administration in the Pacific Northwest has been evaluating methods of reducing hydroelectricity production during high water events in order to avoid overloading the transmission system. However, the reaction to the Bonneville Power Authority's proposals demonstrates that accommodation of renewable sources can create tension with conventional generators. Where a market has been designed for conventional generation, changes will have to be made to resolve these tensions in order for renewable generation to become a significant and efficient part of the energy system.

Chapter 4 explores the legal, financial and socio-economic implications of international renewable energy projects, many of which are positive: optimising natural resources, improved cost-effectiveness, stronger national relationships, financial benefits, skill transference, increased market competition, and back-up capacity. However, there are also legal, financial and socio-economic barriers to establishing cross border projects. An evaluation of the Mediterranean Solar Plan demonstrates that the difficulty once again lies in international cooperation when it comes to finance, certification and regulation.

Chapter 5 discusses the specific challenges related to the promotion of distributed generation from renewable energy by comparing the experiences of Spain and Guatemala with Namibia. In Spain and Guatemala energy markets have been adjusted to provide favourable conditions for distributed renewable generation. In Namibia, however, a new regulatory framework is needed because the energy market is currently not accessible to renewable energy sources (RES), the financial sector is too small to provide subsidies, and there are few RES engineers. Difficulties related to distributed generation can largely be overcome in developed countries, but a lack of infrastructure means this is not always the case for developing countries despite the high potential of renewable sources.

Chapter 6 explores further the challenges faced by some developing countries. China faces barriers, some of which are unique to that country, that impede the efficient use of flexible power production to cope with intermittent and variable output from renewables. In many regions, China's load shape, because of the country's high industrial usage, is relatively flat compared to countries with more residential and commercial electricity consumption. Consequently, historically, China's electric system has needed less load-following and peaking generation, the very kinds of resources that would help respond to renewables' variability.

RES are already an important part of the energy mix in Brazil, although the predominance of hydropower exposes the system to unique risks. As a result, the Brazilian government is looking for solutions to diversify its RES portfolio.

In India, the situation is quite different; the abundance of natural gas and coal makes these resources an attractive option for providing for India's present and future power generation needs. It will be a challenge for India's developers to establish and grow a renewable energy sector that can stand as a viable alternative to coal and natural gas generation to meet India's future demand.

In South Africa the abundance of coal, network congestion, and the lack of a competitive market, is hampering the development of renewable energy generation. In Malawi the development of renewable generation is prevented by the high upfront costs with no financing as well as lack of governmental policy, regulatory framework, and stakeholder coordination. While the potential, ideas and inclination to establish renewable energy generation are all present, the necessary frameworks are not in place. In Algeria, while a regulatory framework for renewables has been created, challenges in implementation still limit investment in renewables and the growth of the RES sector.

These case studies cover a broad range of topics and demonstrate the scale of the challenge. However, they also suggest many potential solutions and effective ways of overcoming obstacles. When it comes to renewable energy generation, where one country is facing difficulties it is often the case that the shared experiences of other countries can help it identify potential solutions. Furthermore, in order to make the most of renewable energy's potential there needs to be increased levels of cooperation, both between companies and industries and internationally. This report highlights areas of mutual interest and demonstrates ways in which countries can work together to improve their own renewable energy generation strategies.

As an example, by considering and comparing the different case studies the following considerations can be provided:

- In developed countries high volumes of intermittent renewable generation starts to affect security and management of the power system, resulting in an increase in operational costs. This spurs debate on the extent to which renewable generators should be responsible for system imbalances and ancillary services to ensure grid stability (e.g. in South Australia, EU Member States and the USA). In developing countries, power sectors are often characterised by insufficient grid infrastructure and less flexibility in terms of power production, load management and storage. Therefore, connecting even a relatively small amount of intermittent generation can exacerbate power system stability and balancing issues. In both scenarios, regulators are faced with similar challenges: to what extent should regulators require renewable generators to bear imbalances risks (e.g. Mediterranean Solar Plan) and to be equipped with devices enhancing their control capabilities (e.g. Mediterranean Solar Plan and China)?

- Electricity markets can help accommodate the integration of growing levels of renewable generation into the power system. Two examples are provided in the report. Firstly, the creation of a single European electricity market and the parallel need to adjust market design rules, which traditionally have been optimised to the needs of national markets and conventional generation. Secondly, the Mediterranean Solar Plan, a supranational scale project helping promote the development of the region's enormous renewable potential. Moreover, in order to facilitate the compliance with EU environmental targets, European legislation envisages cooperation mechanisms to facilitate cross border trade of renewables with non-EU countries which can serve the Mediterranean Solar Plan purposes;

- Energy regulators have to rethink traditional regulatory models and tools (with reference to, for example: planning criteria, cost allocation procedures, business models, etc.) to support large scale deployment of renewable generation. This is reflected in the report, in particular, through the case studies related to Canada and Australia (connecting renewables resources located in remote areas), Namibia, Guatemala and Spain (connecting small scale distributed generation).

Background

The International Confederation of Energy Regulators (ICER) was created at the fourth World Forum on Energy Regulation (WFER) IV, held in Athens in 2009. It is a voluntary framework for cooperation between energy regulators from around the globe. Its aim is to improve public and policy maker awareness and understanding of energy regulation, and play a role in addressing a wide spectrum of socio-economic, environmental and market issues.

Through ICER, energy regulatory issues transcending regional and national boundaries can be addressed through dialogue and cooperation on a global scale. Our membership includes over 200 regulatory authorities and spans six continents.

Since its creation, ICER has endeavoured to build up solid links between Regional Regulatory Associations (RRAs) around the world through its Virtual Working Groups (VWGs) structure. Each VWG works on a specific theme, in order to provide useful and comprehensive material for regulators. The input provided by members of RRAs from all continents makes ICER and its work truly representative of the regulatory community. The VWGs are structured as follows:

VWG1: The Role of Regulators in Guaranteeing Reliability and Security of Supply

VWG2: Climate Change

VWG3: Competitiveness and Affordability

VWG4: Education, Training and Best Practices.

This report is the result of the work of VWG2 during 2011. As with all ICER activities the input provided by RRAs was invaluable for this report. In particular, they provided the wide spectrum of case studies drawn from different parts of the world and therefore different regulatory environments.

Of the 11 RRAs that are members of ICER, seven provided content used in this report:

- The Australian Energy Market Commission (AEMC) and Canada's Energy and Utility Regulators (CAMPUT) provided the majority of Chapter 1;
- The Council of European Energy Regulators (CEER) provided material for Chapters 2 and 3;
- The National Association of Regulatory Utility Commissioners (NARUC) helped to set up Chapters 2 and 3;
- The Association of the Mediterranean Regulators for Electricity and Gas (MEDREG) provided the bulk of Chapter 4;
- The Iberoamerican Association of Energy Regulatory Agencies (ARIAE) and the African Forum for Utility Regulation (AFUR) were involved in producing Chapter 5; and

- Chapter 6 was produced using other case studies from AFUR and several case studies from the Regulatory Assistance Project (RAP).

The drafting of the introduction, conclusion and executive summary was done by members of VWG2 with support from the ICER secretariat.

Introduction

The international growth of renewable energy has been driven by two overarching goals: reducing greenhouse emissions associated with fossil fuel generation, and improving security of supply. There are constantly exciting and potentially fruitful developments in the field. However, this type of generation behaves very differently from conventional generation, and while the technologies are still being established they can be very expensive to set up. Related industries and markets therefore need to adapt their structures and practices in order to fully integrate and enable these new types of energy.

This report assesses international approaches to developing renewable and distributed energy generation, with the aim of revealing the technical and economic challenges facing new renewable projects and the successes and limitations of certain approaches. Case studies from regulatory authorities around the world are used to give an in-depth account of experiences, as well as the thinking behind them.

The majority of the report, Chapters 1-4, focuses on the regulatory challenges to promoting renewable energy.

Chapter 1 addresses the issue of connecting renewable energy to the grid. This is a particular issue because renewable generation often takes place in remote locations far from the existing grid, and so significant investment is required to prevent this becoming a barrier. In Ontario the Energy Board has reformed its regulatory instruments in order to meet the government’s objectives on renewable energy. In Australia the transmission network is a particular concern, and the Australian Energy Market Commission is exploring cross-company cooperation as a means of exploiting economies of scale and to make renewable generation plants more economically feasible.

Certain characteristics of renewable energy require alterations to market arrangements, and this is the focus of Chapter 2.

Energy markets are currently fragmented across national borders in Europe, where steps are being taken to create a single market with the aim of allowing more efficient use of RES.

This report also assesses the domestic measures taken by Germany, Italy, Spain and the UK. In the USA, the Federal Energy Regulatory Commission has proposed changes to organised energy markets in order to better integrate increasing levels of renewable generation.

Chapter 3 assesses the impact of renewable energy generation on conventional generation due to differing system requirements, particularly with regards to intermittency. In Europe there has been a focus on what this means for the provision of back-up generation capacity, with differing approaches taken by various Member States. In the USA, the Bonneville Power Administration in the Pacific Northwest has been evaluating methods of reducing hydroelectricity production in instances of high water levels in order to avoid overloading the transmission system.

There are many benefits to international renewable energy schemes, such as increased market competition and back-up capacity, but there are also legal, financial and socio-economic barriers to establishing cross border projects. These barriers are discussed in Chapter 4. An evaluation of the Mediterranean Solar Plan, which is currently underway, addresses some of these issues and offers potential solutions, as well as a view of the possible benefits.

Chapter 5 discusses the specific challenges related to the promotion of distributed generation from renewable energy. Namibia is looking to develop its renewable energy production in order to supply the rural population with energy. A review of the biomass power project evaluates the barriers to effective distributed generation. In Guatemala and Spain, experience of distributed generation leads to a discussion of: the connection of generation, grid operation, market issues, and the necessary access to information.

The final case studies evaluate the challenges faced by some developing countries and emerging economies. China faces barriers that impede the easy use of flexible power production to accomodate renewables' variability. RES are already an important part of the energy mix in Brazil, although the predominance of hydropower makes it exposed to unique risks. In India, the abundance of natural gas and coal is the main obstacle to the development of a viable renewable energy sector. In South Africa the abundance of coal, network congestion and the lack of a competitive market are hampering the development of renewable energy generation. Although Algeria and Malawi are increasing their generation of solar and wind energy they face economic, governance and skills barriers to taking this further.

These case studies cover a broad range of topics and demonstrate the scale of the challenge. However, they also suggest many potential solutions and effective ways of working. The hope is that knowledge sharing will lead to structures and practices being put in place enable every country to fulfil its goals for renewable energy generation.

1. Connecting renewable energy to the grid

1.1 Introduction

Jurisdictions all over the world have embarked on new energy procurement strategies arising from new climate change policies and obligations. In many instances the relevant authorities have mandated that renewable energy sources (RES), typically wind, photovoltaic, and water based generation, shall comprise specific proportions of the overall energy supply by certain dates. For example, in Australia a renewable energy target has been set for 2020 which corresponds to a tenfold percentage increase in RES. A similar architecture is in place in Ontario, Canada. Ontario's Long Term Energy Plan sees the generation derived from wind, solar and biomass increasing from less than 1% of all generation produced in 2003 to 13% by 2030. - and numerous other jurisdictions.

Implementation of these policies has proven to be challenging from various points of view that will be addressed in this report.

This chapter focuses on the fact that many of the most promising renewable resources, in particular wind generation, are located in remote areas, far from the existing network. This means that significant transmission and distribution costs may be incurred in connecting these sources to the grid. Jurisdictions faced with this problem have tried to develop appropriate regulatory approaches and policies to allocate these costs among market participants. These approaches are outlined in the case studies which follow.

This is an evolutionary process from a regulatory point of view, and endpoints have not yet been reached. In all cases it appears as though the relevant authorities and their regulators continue to develop the tools needed to integrate, and not merely accommodate, significant new renewable generation sources.

The purpose of this section of the report is to outline, through case studies prepared by Canada's Energy and Utility Regulators (CAMPUT) and the Australian Energy Market Commission (AEMC), some of the challenges and issues related to the connection of many more renewable generation sources to the existing grids. Therefore, it will provide an overview of specific measures being taken in the Ontario state and in Australia to address the aforementioned issues relating to grid connection arrangements of renewable energy.

1.2 Connecting remote renewables

In most jurisdictions, renewable resources, especially wind generation resources, can be located in remote areas. The conventional grid has typically been organised to locate generation close to load so that the overall span of the system is limited and concentrated. With the advent of policies mandating the introduction of significant amounts of renewable generation, this approach needed to be amended.

If new renewable generators are solely responsible for the costs of very expensive connections across many kilometres, this form of generation could not succeed. By the same token, it seems unreasonable to burden ratepayers with these costs exclusively.

Regulators have tried to find new approaches which accommodate these competing interests. For example, in Ontario, the regulator has developed a methodology which burdens a renewable generator with only those costs of connection attributable to its specific capacity. The remainder of the cost is borne by all of the ratepayers within the system until such time as additional generators develop their contiguous facilities and connect to the grid. When they do they pay their proportionate share of the connection costs. This enables development to occur in stages and at a cost to generators which is proportional and which can be reasonably financed by the project.

In addition, in Ontario, the generation procurement arm of the government conducts an assessment of the merits of a particular project and its associated connection costs. In this way effective planning occurs, and connections that are genuinely uneconomic can be avoided. The Ontario case study outlines further measures undertaken by the various authorities within that jurisdiction to foster appropriate renewable generation connection.

The Australian authorities are developing various mechanisms which are designed to ensure that appropriate development takes place without undue burden to developers or ratepayers. AEMC is currently engaged in detailed consultations with market participants in an effort to identify the optimal approach to achieve these goals. The various options under consideration are outlined in the corresponding case study.

These themes are explored as well through the balance of the case studies presented in this section. These case studies demonstrate the need for a measured and evolutionary approach to the integration of significant amounts of new renewable generation into conventional grids. It will take time and experience to develop the optimal mechanisms to balance the variety of interests engaged in this process. From a starting point of very demanding renewable generation mandates, regulatory regimes have generally paused to ensure that this development is managed in a responsible and sustainable manner.

1.3 Case study 1: Implications of the Green Energy and Green Economy Act for Ontario (Canada) electricity regulation

Electricity regulation in Ontario by the Ontario Energy Board (OEB) was established in the context of an electricity market where investment in generation was driven by the market and generators competed with one another. The OEB was made responsible for regulating transmission and distribution. The OEB's policies were aimed at ensuring that appropriate levels of investment in these sectors were made to meet the needs of stakeholders and that the costs of such investments were fairly allocated amongst beneficiaries.

In 2009, the Ontario government passed the Green Energy and Green Economy Act. Since then, the energy sector in the province has been undergoing significant change. The objective of this new policy, codified in the legislation, is to create a 'greener' economy and then the conditions for new green jobs that go with it. Under this approach, greater investment in renewable generation is desired and such investment is not limited by or necessarily linked to customer need. The Ontario Power Authority's Feed in Tariff (FIT) program is the driver of that investment.

Ontario Power Authority's FIT program

The Ontario Power Authority (OPA), a provincial government agency, launched a FIT[1] program in September 2009. There was an overwhelming response, with early applications totalling over 15,000 MW in total capacity. This amount of capacity greatly exceeds the current ability of the transmission or distribution systems to connect it. Therefore a lot of transmission and distribution investment will be needed to connect this generation and sustain the momentum of the program. To a large extent the OEB regulates this investment activity.

Regulatory instruments need to be retooled

The OEB has many instruments that influence the connection of renewable generation through its oversight of network rates and investment, through rules governing the allocation of existing connection capability, and through other rules governing the allocation of connection costs.

Over the past year or so these instruments have been amended to meet the mandate created by the policy and the legislation, and to expand the system. What follows is a brief description of the five broad categories of regulatory response to this new environment.

Generally the response can be grouped as: more rational and efficient connection processes for generators; simpler settlement processes for FIT; the shift of costs from generators and sharing them among ratepayers; dealing with distributor owned generation; the encouragement of rational planning and investment. It can be seen that some of these objectives are conflicting.

More rational and efficient connection processes

The OEB has made it easier for generators up to 500 kW to connect to their local distribution system by exempting them from getting a specific allocation of capacity. For larger generators there were a number of cases where generators had been allocated capacity in the past but were not moving forward with their projects. The OEB now requires them to pay a deposit to retain their capacity allocation, this provides an incentive for developers to

[1] A feed-in tariff (FIT) is a regulatory tool that "encourages new renewable energy development by creating a long-term financial incentive to customers who generate renewable electricity, and offering a standardized and streamlined process to do so, easing the entry for new systems. Under a feed-in tariff, a utility is contractually obligated to connect the renewable energy generator to the grid and pay that generator for electricity at a fixed rate for the life of the FIT contract, typically 10-20 years. The goal of a FIT is to create a robust market for renewable energy to lower technology costs and increase development of such resources for the duration of the program, and potentially pave the way for future growth. The design of FITs can vary considerably in how rates are calculated, eligibility of different technologies and resource sizes, and the contract terms." (From NARUC's *Feed-in Tariffs (FIT): Frequently Asked Questions for State Utility Commissioners* 2010, available at http://www.naruc.org/grants/programs.cfm?page=61)

pursue or abandon these projects. Generators with FIT contracts have been exempted from this requirement since the OPA requirements already requires to hold significant deposits attached to the FIT contracts themselves. Finally, the OEB has introduced a new simplified generation licence for FIT generators.

This will reduce the paperwork burden for these generators and avoid duplication with the OPA's own processes.

Simpler settlement arrangements for FIT and microFIT generators

Both the Board and distributors were concerned with how to ensure efficient processing of FIT and microFIT accounts. This was going to be particularly challenging considering that thousands, and potentially tens of thousands of microFIT generators would be connecting to the system, and that the billing and settlement arrangements would vary by the type of connection (e.g., in front of or behind the meter).

The Board has revised its codes so that there is now a single standardised way of setting up these accounts and settling them, regardless of whether they were connected in front of or behind the meter. In both cases, the customer receives their gross amount of electricity production times the applicable price as payment. The customer also pays for their gross electricity consumption at the applicable rate, this rate includes distribution and other charges. This standard approach will greatly simplify the task facing distributors.

The Board also recognised that the generation account required the creation of an appropriate monthly charge to reflect the costs of serving a generation account. A standard charge of $5.25 per month has now been implemented for renewable generators smaller than 10 kW in size.

Shift costs from renewable generators and share fairly among ratepayers

Under the former cost responsibility rules, the Board required generators to pay for the costs associated with connecting their facilities to a local distribution system. This included the costs of upgrading the system itself.

The Board recognised that the FIT program was likely to lead to a large number of generators connecting to distribution systems. However, Ontario's distribution systems were not really built to handle a significant amount of generation. It is going to be necessary for distributors to make substantial investments to accommodate distribution connected renewable generation and make the system 'generator friendly.' The Board decided that it would be best to shift the cost of this system overhaul from individual generators to load customers as a whole.

The Government determined as well that the costs for upgrading the distribution systems should be borne evenly across the province as a general societal benefit. It has charged the Board with the responsibility of ensuring that the cost burden of these additional investments is shared equitably among distribution connected ratepayers across the province. This broad 'socialisation' of these costs shifts liability for these costs from the customers of the specifically impacted distribution systems to customers of the broader system. In doing so the costs burden for any particular customer is obviously substantially reduced.

Deal with distributor owned generation

The new legislation permits electricity distributors to own renewable generation facilities of 10 MW or less within the distribution company, rather than as separate affiliates. The Board has made it clear through its guidelines that while these installations can be operated within the rate-regulated utility, the distributors can't put these generators in their ratebase and the associated accounting treatment for them is as a non-regulated activity. Ratepayers will not be subsidising these installations. Amendments to the Board's codes have been issued to make requirements on generation affiliates more flexible, but also to create an enforceable obligation of equal treatment as between a distributor's own facilities, and those of third parties wishing to connect to that distributor's system.

Encourage rational distribution planning and investment

Network expansion is the key to sustaining investment in the green economy. The scale of the investment required means that network owners need to plan their investments. The need to move quickly must be balanced with the need to make rational investment decisions at a pace that does not create additional costs for customers.

The distribution planning guidelines issued last year provided a framework for the distributors, of which there are 79 in Ontario.

Deferral accounts were established so distributors could book expenditures and also apply for a funding rate adder to create needed cash flow support. Guidelines were also issued to trigger what the Board expected to see in a distribution system plan.

Encourage rational transmission planning and investment

In contrast with distribution system investment, which can happen relatively quickly, transmission investment takes longer to carry out. The government has identified up to 20 additional transmission lines that might be needed in the medium term to connect prospective renewable generation. To address this, the Board has put in place a new process for connecting clusters of renewable resources to the transmission system by encouraging transmitters to establish connections to these clusters rather than leaving this responsibility to the generators themselves. The Board has also adopted an incentive approach to transmission (and distribution) investment to either shift more risk to ratepayers and/or to make provision to offer higher rates of return for 'riskier' projects, or where circumstances otherwise favour such an approach. Finally, the Board approved in August 2010 a competitive process to encourage outside investment in developing major new transmission facilities in Ontario. The Board's measures have made transmission projects undertaken generally more susceptible to competitive processes.

It should also be noted that the Green Energy Act created significant new Conservation and Demand Management (CDM) obligations for distribution utilities. Aggregate CDM targets were established by the Ontario government for the period 2011-14. These targets consist of a peak demand target of 1330 MW persisting at the end of the four year period and 6000

GWh of reduced electricity consumption accumulated over this same timeframe. These aggregate targets were then spread across all 79 electricity distributors and made a licence condition. The Board has a direct role in ensuring that these CDM targets are met and that the utilities follow the rules and requirements that the Board has set out for them to follow in a CDM Code.

Following the roll out of Government's program rolled out, the Board felt that a review of its regulatory approach was necessary to ensure it meets all its objectives,, including protecting the interests of consumers. To that end the Board has embarked on a consultation with the regulated entities, generators and consumers to consider the introduction of regulatory approaches which would require regional planning activities in support of system expansion, a more refined consideration of rate mitigation activities and the pace of change.

Conclusion

As a consequence of the Green Energy and Green Economy Act, a surge of renewable electricity generation is seeking connection to the province's transmission and distribution systems. To accommodate this, the OEB has had to extensively 'rework' its regulatory instruments related to the connection of renewable generation and to the planning and expansion of the transmission and distribution systems. This calibration continues in a very dynamic policy and technical environment.

For example, the prices paid for certain renewable projects under the FIT program have been recently reduced and the Ontario government has now undertaken a complete review of the FIT program to examine program rules and pricing to ensure the program remains successful and sustainable.

In another development, generators whose projects require upgrades to the existing infrastructure may be delayed in their connection to the system until such time as the additional capacity is created according to a more conventional expansion process and timetable. Additionally, the system operator is currently studying the need to make renewable sources genuinely dispatchable in a manner that was not initially contemplated.

The Board expects that through this revised framework, government objectives related to the promotion of renewable energy can be achieved at a lower cost to consumers, with respect to price, reliability and quality of service, than would have otherwise been the case.

1.4 Case study 2: Facilitating connection for renewables in Australia

An emissions trading scheme now looks set to be introduced in Australia by the middle of 2012. Currently, however, the principal climate change policy at a national level is the *Renewable Energy Target* (RET).

The RET requires energy retailers in Australia to source a certain percentage of their energy supply from renewable sources.

Under the scheme each unit of energy (MWh) produced from renewable sources creates a tradeable renewable energy certificate (REC) and energy retailers must surrender their allocated proportion (based on market share) of RECs every year for compliance purposes. Retailers who fail to meet the target must pay a penalty price.

Australia passed legislation in August 2009 which expands the original 2% RET in linear fashion (annual targets) to 20% of energy supply by 2020. This is anticipated to increase renewable generation capacity in the National Electricity Market (NEM) from less than 2000 MW operating currently to potentially 10,000 MW by 2020.

Wind powered generation, given its expected cost trajectory relative to other renewable technologies, is expected to make up the majority of this new investment.

Like elsewhere in the world where substantial carbon reduction policies have been introduced, Australia is grappling with the technical and economic issues of integrating large amounts of renewable generation into its electricity networks. Two issues in particular have attracted policy attention in Australia:

- The extent to which high volumes of intermittent plant will impact on the security and reliability of the network; and
- Whether existing network planning and investment arrangements will be sufficiently responsive to the need for a fundamental shift in the location and type of generation investment to meet climate change policy objectives. The existing network has been built largely to accommodate Australia's extensive coal resources.

In this chapter we will focus on the second point. The impact of intermittency on network reliability and security will be addressed in Chapter 2.

A number of different aspects of the transmission arrangements are currently being examined by the AEMC.[2] These include the pricing and access on transmission networks and the cost-benefit framework which underpins network investment. However, one aspect of the transmission investment arrangements has received particular attention as a possible weak link in achieving climate change policy objectives, namely the framework for connecting generators.

The generator connection arrangements have been under review by the AEMC over the past two years. The evolution of thinking on the generator connection framework and the extent to which this can and should support climate change policies will form the first AEMC case study analysed in this paper.

The role of networks in facilitating achievement of challenging renewable energy targets is an issue which is increasingly occupying the minds of regulators and policy makers around the world. This case study will provide an Australian perspective.

Before examining the first case study in detail a brief overview of the regulatory and market arrangements operating in Australia is provided below.

[2] The AEMC is a national regulatory body which develops the market rules for conduct in energy markets, undertakes reviews and advises Australian governments (both federal and state) on energy policy matters.

Australian market and regulatory framework

Like energy markets in many developed countries around the world, the Australian energy market was deregulated and unbundled in the 1990s. Competitive markets were created for retail energy supply and generation supply, while networks remain tightly regulated with access provided on a non-discriminatory and cost-reflective basis. A National Electricity Market (NEM) was established in 1998 across the states of the eastern seaboard (New South Wales, Victoria, Tasmania, South Australia and Queensland).

The energy markets and networks in Australia are subject to the National Electricity Law (NEL) and National Electricity Rules (NER). The NEL sets out the governance arrangements for the various institutional bodies involved in energy markets, while NER sets out the rules and responsibilities of participants with respect to the operation of the NEM and regulation of networks.

National energy policy is developed by the Ministerial Council on Energy (MCE), which is chaired by the Federal energy minister and has ministerial representation from each of the states and territories.

This reflects the fact that much of energy policy in Australia is still the responsibility of the states. While policies are devised by governments they are implemented through the AEMC, which is responsible for developing and amending the NER and advising the MCE on policy development and market design.

Competition issues are dealt with by the Australian Competition and Consumer Commission (ACCC) who administer the Competition and Consumer Act (CCA). The CCA underpins Australia's competition law framework.

Regulation of networks

Network regulation is set out in the NER. Transmission and distribution networks are owned and operated by Transmission Network Service Providers (TNSPs) and Distribution Network Service Providers (DNSPs). A single TNSP manages the high voltage networks in each Australian state (generally above 200 kV). There can be more than one DNSP in each state. Some TNSPs and DNSPs are government owned and some are private. TNSPs and DNSPs are required to provide non-discriminatory third party access and are also responsible for investing in networks to ensure state based reliability standards are met.[3]

Transmission and distribution frameworks are subject to access and revenue regulation which is monitored and enforced by the Australian Energy Regulator (AER).

The AER determines the revenues that transmission and distribution companies are allowed to earn over a five year time frame as well as the conditions and pricing of access. The AER also approves the planning of and investment in transmission and distribution networks.

[3] For a good discussion on the network regulatory arrangements see AEMC Scoping paper, "Review of the Electricity Revenue and Pricing Rules" November 2005 available at http://www.aemc.gov.au

Transmission pricing and access

The transmission network in Australia is operated on the basis of open access. Open access in this context means that generators and load customers (such as large industrial customers and distribution network service providers) are, subject to the appropriate regulatory approvals and payment of relevant charges, able to access the network on a non-discriminatory basis.[4] In practice, access to the transmission network is determined by generator dispatch offers on a non-firm basis (there is no compensation for generators who are constrained down due to network congestion).

Current transmission charging arrangements operate under a 'limited' causer pays framework, where generators only pay for the specific assets (connection assets) required to connect them to the transmission network, i.e. link capex.

Generators do not incur any additional charges associated with investment in or deeper reinforcement of the transmission network, which may be triggered by, or associated with, their connection to the network. These are funded by consumers through regulated charges.

Transmission investment

TNSPs primary responsibility is to ensure that the transmission network can deliver energy at a minimum N-1 redundancy standard (all consumer demand can be met despite the loss of any single element of the network). They must also ensure transmission investment supports the overall reliability standard, which requires that consumers should not face disruption to their energy supplies more than 0.002% of the time. TNSPs are responsible for investment in the transmission network. However any transmission requirements that relate to connecting to the network are the responsibility of generators (although TNSPs will often construct and operate them). Each investment they undertake for reliability purposes must pass a cost-benefit test, to ensure it is the most efficient option.

The cost-benefit analysis used in the NEM is referred to as the Regulatory Investment Test for Transmission (RIT-T),[5] which also requires extensive consultation with market participants. TNSPs are required to undertake the RIT-T for all investments in the network over five million dollars. The RIT-T assesses the benefits and costs of investing in a particular transmission option against credible alternative options under a range of scenarios. TNSPs are required to choose that investment option that either minimises system costs in meeting demand or maximises total market benefits of the option (compared to the credible options considered).

All relevant benefits and costs are taken into account in an application of the RIT-T. This includes any benefits transmission might bring to expanding the scope for generator competition, or reducing costs incurred in meeting climate change policy objectives (for

[4] See AEMC scoping paper (note 3), note 10, at 39.

[5] Ibid at chapter 6.

example if the investment option allows the dispatch of more low cost renewable generation relative to other possibilities in the market).[6]

Wealth transfers between producers and consumers or different classes of participants are generally excluded from the analysis, and are not considered when determining whether a particular transmission option (or non-network alternative) is chosen or not.

Addressing the coordination failure for RES deployment

In order for Australia to meet challenging climate change objectives, very substantial investment in renewable generation capacity is required. In Australia, as elsewhere in the world, some of the best renewable resources (such as wind, geothermal and solar) are located in areas remote from the existing network, or those areas closer to the network with little or no available transmission capacity. This is because the transmission network has to date largely been developed to accommodate fossil fuel resources, which are typically located in different areas to where the best renewable sites are situated.

In 2008, the AEMC was asked by the Australian government to review energy market frameworks to assess whether they could continue to operate effectively under an expanded RET and potential national emission trading scheme (ETS).[7] While the review found that existing market arrangements were largely robust, it identified networks as a potential weak link in supporting climate change policy objectives.

The key issue of concern was that many of the best renewable resources are located in remote areas with currently little or no transmission capacity. Under existing transmission investment arrangements however, TNSPs are only responsible for investment within the network itself, and only investment within the network itself is paid for by consumers. Transmission lines required to connect remote generators to the network were the responsibility of generators themselves. The upfront costs of such lines for individual or even small groups of generators could be prohibitive however. This in turn could have an adverse effect on investment in renewable generation, potentially undermining long term climate policy objectives. The AEMC was tasked by the MCE to assess this issue and consult on a number of possible ways for reducing the upfront costs or risks associated with privately funded investment in transmission.

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[6] These are both relatively new features of the RIT-T, transmission benefits associated with competition and climate change policies have yet to be used in application of the RIT-T, however an approach for doing so is included in the latest RIT-T guidelines which can be accessed at http://www.aer.gov.au/content/index.phtml?itemId=730920

[7] See AEMC Final Report (2009) "Review of Energy Market Frameworks in Light of Climate Change Policies" available at http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-Energy-Market-Frameworks-in-light-of-Climate-Change-Policies.html

The AEMC commenced consultation on possible options in early 2010[8] and subsequently released a final decision on 30 June 2011.[9]

Five different options were initially released for consultation with the market. The basis for all options was creation of a new type of connection transmission asset referred to as a Scaled Efficient Network Extension (SENE). The SENE concept sought to reduce upfront costs for participants by taking advantage of economies of scale in transmission (and thus lowering unit costs of transmission access)[10] and defraying costs through some form of sharing mechanism.

The various options considered in this consultation differed primarily on the basis of how the costs of the SENE were shared between generators and consumers, and the degree of analysis and planning required to justify the construction of a SENE in the first place.

While five different options were presented for consultation, they essentially boiled down to two key options.

Option 1 required that consumers fund the upfront costs of the SENE, but with full reimbursement from new generators as they connected over time. In contrast, under option 2 'first movers' would bear the upfront cost of the SENE, with subsequent reimbursement from newly connected generators. Differences in planning approaches also underpinned each option.

The broad detail of these two options and the rationale for why the AEMC ultimately settled on the second approach is discussed below.

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[8] AEMC "Options Paper: National Electricity Amendment (Scale Efficient Network extensions) Rule 2010" available at http://www.aemc.gov.au/Electricity/Rule-changes/Open/Scale-Efficient-Network-Extensions.html

[9] AEMC, "Draft Rule Determination, National Electricity Amendment (Scale Efficient Network Extensions) Rule 2011" available at http://www.aemc.gov.au/Media/docs/Draft%20Rule%20Determination-c44e303f-6613-43b9-b3da-af8b0250b04d-0.PDF

[10] Economies of scale mean that the cost of transmission per unit decreases with size. For example, it would generally be more expensive to build separate transmission lines to meet the needs of each individual generator compared to building a single larger line of equivalent capacity to meet the needs of generators collectively. Generators will subsequently face significantly lower transmission costs by taking advantage of scale economies.

Option 1 – consumers fund upfront costs of SENE

Planning

This option commences with a central planning process, managed by Australian Energy Market Operator (AEMO), which identifies zones of high renewable resource potential each year in its national transmission plan (NTP).

Identification of these zones would be supported by an appropriate level of consultation with market participants and TNSPs.

The TNSP with operational responsibility for the zones identified would then be required to undertake indicative planning for possible SENE options out to these zones. Such planning would involve TNSPs developing a number of different SENE options, which varied on the basis of size and configuration and the consequential costs generators would face under each option. The ultimate decision would balance scale efficiencies and the level of demonstrated market interest against the likelihood of the asset becoming stranded (that future generators would not turn up). To help mitigate this risk a key feature of this option is a ‘market interest’ test, which requires that at least 25% of the costs of the SENE are secured in funding upfront. However, TNSPs would also need to undertake detailed modelling to assess prospects for future entry.

The AER would have the power to veto the proposed SENE if it was not satisfied that future forecasts of generation entry were reasonable, or that the ‘market interest’ test (minimum 25%) had been met. Once approved by the AER construction would commence.

Cost allocation

Under option 1 each generator, regardless of when they sought to connect, would face a fixed annual charge over the expected life of the SENE which is set to recover the proportion of the asset they use (usually but not necessarily equal to the generation capacity they connected to the SENE).[11]

Second, given the minimum 25% commitment required from generators, consumers would be required to initially fund upfront a maximum 75% of capacity of the SENE (although less if more generators put their money on the table at the outset). However, the proportion funded by consumers is ultimately reimbursed (in their regulated retail tariffs as new generators connect over time).

Therefore the intention of this option is for generators to fully fund the SENE, but for consumers to bear the upfront risk that not all the capacity constructed becomes fully utilised by generators.

Generators would be entitled to a defined level of transfer capability on the SENE, which means that once the asset is fully subscribed, new generators wishing to connect would

[11] For a detailed explanation see the Options Paper.

need to fund additional capacity on the asset. This intends to replicate the situation of a sole use connection asset, where generators have full rights over that asset.

It is important that generators who pay for their proportion of the SENE can expect to be able to utilise the associated transfer capability at their discretion, and not have this appropriated by others without recompense.

Option 2 - generators (or investors) bear upfront costs of SENE

This option is largely driven by the perspective that consumers should bear no stranding risk, and reflects a more decentralised approach to transmission investment and planning relative to option 1.

This approach represents only an incremental change over and above existing arrangements in Australia, largely focused on better information provision and an obligation on TNSPs to undertake relevant analysis upon request.

The Australian Energy Market Operator (AEMO) does not choose the renewable zones where SENEs should be built, nor are TNSPs compelled to develop SENE options. Rather, generation investors (or some consortium thereof) decide if, when and where a SENE should be developed.

However TNSPs are obligated to undertake, on request, specific planning studies to reveal to the market the potential opportunities for efficiency gains from the coordinated connection of generators in particular areas. The focus of the study is to assist potential investors to make an informed, commercial decision to fund and share the costs of a SENE. Once a study is published, the decisions to fund, construct, operate and connect to a SENE are made by market participants and investors within the existing framework for connections and transmission investment in the NER.

Construction occurs once a generator establishes a connection agreement with the TNSP for access to the SENE. This requires the generator(s) to fund the SENE upfront.

While first mover generators must initially fully fund the SENE, they will have the ability to recover costs of the SENE as other generators connect. The first mover generators therefore take the risk that no further generators are built (in which they will pay for excess capacity) but the incentive to do so is the prospect for significantly lower unit transmission costs if such generators are built.

This approach therefore leads to a very different allocation of costs and risk between customers and generators as compared to the first approach. The first movers pay higher upfront costs, and this cost reduces over time as other generators connect. Conversely, under option 1 the charge is much lower and is fixed upfront for generators. The key point is that the first connecting generators or investors bear the bulk of the stranding risk under the second approach.

Final AEMC decision

After considering the various SENE options outlined in its initial consultation paper (variants of option 1 and 2 discussed here), and submissions from market participants, the AEMC decided to implement option 2. AEMC's rationale is set out in full in its final determination of 30 June 2011.

The determining factor was the AEMC's concern over potential asset stranding. This was considered important for two reasons. First, if generation forecasts do not materialise then a SENE is overbuilt and consumers end up funding excess transmission capacity. Yet they are perhaps least well placed to manage the risks of this occurring. Second, asset stranding provides a subsidy to first mover generators that do happen to connect. They pay a charge substantially below their actual stand-alone costs of connection (they still receive the benefit of the reduction in their transmission charges due to economies of scale). To the extent generators connecting elsewhere in the network have been required to pay their full stand-alone connection costs then this may distort competitive neutrality, possible between competing renewable energy options.

On balance the AEMC considered that the 25% interest test and future generation forecasts under variants of option 1 provided insufficient rigour around appropriately sizing the SENE, which exposed consumers to excessive stranding risk. It was considered that participants or investors, rather than consumers, were likely to have the better information, capability and incentive to weigh the benefits of scale efficiencies versus stranding risk. The key strength of option 2 is that it places the risk of stranding with those best able to manage it: private commercial enterprises.

2. Impact of wholesale market and system operation arrangements on renewable energy generation

Wholesale market arrangements and system operation rules play an important role in promoting the integration of renewable energy. The unique technical characteristics of some renewable technologies, such as variable output, and the fact that generation often consists of numerous small scale projects that may be located far from major demand centres, requires favourable wholesale market design arrangements and system operation rules in order to integrate large volumes of renewables into the system. Depending on how they are adjusted, market arrangements and system operation rules can significantly affect the competitiveness, economic efficiency and operation of RES generators, and therefore might either promote or obstruct its integration.

This chapter analyses the impact of market design arrangements and system operation rules on renewable energy generation. It defines the key areas of market design and system operation and explains their impact on RES generation. The chapter then proceeds with specific case studies on Australia, Europe and the USA which were prepared by AEMC, CEER and NARUC respectively.

The intention of these case studies is to present practical experiences of different countries in their electricity market and system designs to adjust to a growing share of renewable generation. ICER believes this will allow for the intellectual exchange of ideas and policy measures with regards to market design and system operation aspects of renewable integration.

2.1 Wholesale market arrangements

Wholesale market design refers to how generation is offered to the market and traded within it. This concerns issues such as gate closure times (GCTs), responsibility for balancing and forecasting[12] and cross border capacity allocation. All these aspects of market design should be taken into consideration as a whole rather than on an individual basis.

Gate closure times

To begin with, it is important to consider the impact of GCT on renewable generation. GCT refers to the last moment in which market players are able to trade electricity or inform the balancing-responsible party (BRP) of their position before real time delivery without affecting their balancing position (where this is relevant). For the purpose of this work, we will refer to the GCT as the intraday gate closure rather than the day-ahead gate closure where there is a difference between the two.

[12] Depending on the forecasting method this can be regarded as either market design or system operation, but for the purpose of simplicity we address forecasting issues as a whole in the ‘wholesale market arrangements’ section of the introduction.

The time of gate closure is particularly important for wind generation, as it can be difficult to forecast ouput at the day-ahead or further out stages. The closer to the real time the GCT is, the easier it is to forecast variable RES generation outputs precisely.

For example, the day-ahead forecast error in Germany is over 20%, but decreases significantly closer to real time.[13] Short GCTs bring mutual benefits for both the system and generators as it reduces the possibility of system imbalance, thereby allowing generators to avoid imbalance charges and reduce their operational costs. In countries where power is traded cross border, close to real time and harmonised GCTs would facilitate trade and promote competition.

Cross border capacity allocation

Another aspect of market design that is important to renewable generation and can promote its further integration in interconnected market areas is cross border capacity allocation, e.g. the way in which capacity on an interconnector between two adjacent price areas is allocated. Available interconnector capacity is usually allocated within different timeframes on three markets: forward, day-ahead and intraday. In general, the biggest share of capacity is allocated on a long term basis and the remaining capacity is made available for the day-ahead trade. Intraday markets usually only offer unused capacity from day-ahead and forward markets.

Several cross border capacity allocation methods exist. For long term allocation, either bilateral trading or competitive auctions can be used. For day-ahead and intraday markets, capacity is mainly allocated using two different methods: e.g. explicit or implicit auctions. In an explicit auction the transmission capacity on an interconnector is sold to the market separately from where electricity is auctioned.

Conversely, in implicit auctions the transmission capacity between price areas is made available to the spot price mechanism in addition to bid/offers per area.

The resulting prices per area reflect both the cost of energy in each internal price area and the cost of congestion. Implicit auctions ensure that electricity flows from the surplus areas (low price areas) towards the deficit areas (high price areas), leading to price convergence.[14]

Cross border capacity allocation is of particular importance to all market participants, not just renewable generators. Efficient capacity allocation methods allow for better use of existing cross border infrastructure (e.g. by reducing congestion) and promote integration of adjacent energy markets, thus creating more trading opportunities. This results in increased competition and market efficiency with more accurate and transparent prices resulting, ultimately benefitting end consumers.

[13] Weber (2009), "Adequate intraday market design to enable the integration of wind energy into the European power systems".

[14] For more detailed descriptions please refer to: http://www.nordpoolspot.com/PowerMaket/The-Nordic-model-for-a-liberalised-power-market/Implicit-auction/

Optimal cross border capacity allocation can also help to mitigate volume fluctuations caused by variable wind and solar patterns. This is particularly relevant to markets with high levels of renewable energy penetration as it allows either party to export their surplus or to import their deficit into the system. Thus efficient cross border capacity allocation can help to promote renewable energy integration beyond domestic borders.

However, when creating cross border capacity allocation mechanisms the specific characteristics of renewable energy generation must be given special consideration to allow renewable generators to effectively participate in cross border trading.

Balancing obligations on renewable energy generation and the role of the Transmission Service Operator (TSO) in balancing

In order to maintain security and quality of the supply in the system, since electricity cannot be easily stored, electricity supply must equal demand within the operational period. Market participants should be incentivised and provided with the means to be balanced.

Balancing for some renewable technologies, such as wind and solar photovoltaics (PV), is more complicated than for conventional generators, given the difficulty in forecasting their outputs far from real time. Unless the system provides renewable generators with efficient tools to balance, renewable generators are more prone to incurring imbalance charges, which negatively affects their competitiveness. In addition, large levels of renewable generation that are unable to balance effectively would pose an operational risk to the system, as it would be more likely to be out of balance.

In general renewable generators are either obliged to balance their positions, as are all other market participants, or are exempted from balancing obligations.

In the latter case, the transmission system operator (TSO) takes care of any imbalances caused by renewable generators and socialises the costs incurred. This option requires strong incentives for the TSO to operate the system and its reserve capacity in an efficient way in order to avoid incurring high balancing costs. It also requires a centralised approach to forecasting (see below).

Forecasting non-programmable renewable energy generation

Forecasting is an essential tool that helps renewable generators assess meteorological conditions and predict their outputs accurately. It benefits markets by reducing costs and improving operational security.

A study conducted in the USA shows that the cost-benefit ratio of forecasting can be 1:100.[15] Accurate forecasting is indeed essential for systems with high levels of renewable energy penetration as it reduces overall system tendency towards imbalance due to variable renewable generation.

[15] Quoted in European Wind Energy Association (EWEA) (2010), "Powering Europe: wind energy and the electricity grid", p.71.

In practice, forecasting can be done in a decentralised manner, e.g. by renewable generators themselves or by using a centralised approach. In the latter case either the market offers centralised forecasting services by collecting weather forecasts and aggregating all wind/solar plants' data or forecasting is done at a system level (by the TSO) as an input to the balancing market and imbalance costs are paid for by consumers.

2.2 System Operation

System operation rules define how the system is operated by the TSO. With the share of renewable generation growing, it becomes increasingly important to readjust system operation rules in order to be able to adapt to the changing nature of electricity generation and the specific characteristics of renewable generation. In particular this concerns system security as RES generation poses a challenge to system balancing by TSOs.

Technical requirements of TSO for connecting and managing renewable energy generation

In order to connect to the system, any form of generation connecting to a transmission (or distribution) network will be required to meet certain technical criteria. It is essential to have such connection criteria to ensure the operational security of the network and that the performance of the generator in response to varying conditions can be foreseen.

The growing levels of large variable generation being connected to electricity systems across the globe presents challenges to system operation.

For instance, intermittent generation can hardly be modulated alongside the system load curve; such generation sources are often located in dispersed areas far from load centres, thereby increasing interconnection costs.

Furthermore, older intermittent generation may not have low voltage ride-through capabilities. When large amounts of intermittent power are injected in semi-isolated systems with low levels of reserve capacity generation (typically large hydro, pump storage and open cycle gas-fired turbines), measures must be taken to integrate large scale intermittent power integration safely. Even in densely meshed networks, large, irregular intermittent power intakes may induce large scale loop flows that are difficult to anticipate. Such flows can create significant volatility in otherwise easily predictable cross border flows. Grid connection rules must also be adjusted to the unique characteristics of renewable generation to enable renewable generators to compete in the market with conventional generation.

In this light, grid connection requirements for all large scale renewable generation resources should take into account specific technical characteristics and define operational rules for renewable generators regarding balancing and reconnection after tripping in order to ensure stable system operation.

Priority of dispatch of renewable generation

Another important aspect of system operation is the dispatch of electricity from generation units. This concerns the method and the order in which electricity is dispatched to the system by generators. In general, the dispatch can either be centralised (e.g. controlled by the TSO) or decentralised (self-dispatch). In centralised dispatch a 'merit order' (e.g. the price optimisation process, whereby plants with the lowest short-run marginal costs dispatch first) is usually established to determine the priority of generators' dispatch. In this case the TSO assumes responsibility for balancing the system. A decentralised approach places primary responsibility for dispatching on the grid users and therefore requires an effective imbalance settlement mechanism. Self-dispatching is used, for example, in Great Britain. This system will be described in Case Study 4 (The integration of renewable energy in Europe).

It is important to ensure that renewable energy generators have access to the system and can compete on an equal footing with conventional generation. There are several ways to achieve this objective. In systems with a centralised approach, renewable generators could be given a priority to dispatch ahead of conventional generation. As an alternative, when a merit order is established, generators would be given a fair competitive advantage as their short-run marginal costs are usually the lowest. In a decentralised approach, self-dispatch could be utilised. Again, access to the grid is determined by price signals (e.g. by the 'merit order'). For renewables to be able to compete, this requires short GCTs and good forecasting techniques to help variable renewable generation stay in balance and avoid incurring imbalance charges.

Provision of network/system services by renewable energy installations

System services such as reserve capacity, frequency response, black start process and balancing are necessary for maintaining system stability and operational security.

Initially, variable renewable generators were not required to provide system services. However, as more conventional generation units, such as coal and nuclear power plants, are retired, in the long run TSOs will inevitably have to rely on renewable generators to provide system services.

Providing system services is more complicated for variable renewable generators; however, improvements in forecasting techniques would increase the reliability of the system services which they provide. Nevertheless, some renewable generators are already able to provide a number of system services, such as black start services, electricity storage (to address intermittency) and frequency response.

2.3 Security and reliability issues

The following examples will outline some of the technical stresses placed on conventional grids by renewable generation sources and the measures which have been adopted to try to mitigate them.

A number of jurisdictions have attempted to develop forecasting methodologies to allow grid operators to have a much more precise idea of how much renewable generated electricity will be entering the grid and when. This information can be crucial, not just from a market operation point of view, but also to allow the system operator to minimise unstable and insecure conditions on the grid.

Some regulators and system operators have required the renewable generators to adhere to a suite of market rules which would require them to play a much more conventional role in overall market operation and supply through the bid process, dispatch, and control or constraint. In the early stages of new renewable generation deployment it was unclear how issues such as dispatch, constraint, and some of the cost consequences associated with full market participation would be applied to the renewable generation sector; this perception is now changing.

Some regulators and system operators also noted that introducing significant new renewable generation can destabilise the transmission system. The conventional fossil fuel generator is an important source of reactive power and contributes significantly to maintaining voltage stability.

As more and more wind generation replaces conventional generation, the stabilising effect can be lost unless additional reactive power equipment such as a static var compensator (SVC) is added to the grid. Some new wind generators have such capability but earlier ones do not. To mitigate this problem, some regulators have enhanced the technical requirements of wind generation.

2.4 Conclusion

All in all, market design and system operation arrangements are of particular importance to renewable energy integration. In order to accommodate large volumes of RES generation these arrangements should be adjusted to address the specific technical characteristics of renewable energy. As briefly outlined above, there are number of ways to adjust market design and system operation arrangements to enable large scale integration of renewable energy generation. These practices differ from market to market according to the specific circumstances of the market. The following part of the report presents several approaches to market design and system operation that are affecting wholesale market design and system operation. The case studies prepared by AEMC, CEER and NARUC will set out major issues in Australia, Europe and the USA and describe how they are being addressed.

2.5 Case study 3: Intergrating renewables in South Australia

One of the issues that has attracted considerable policy attention in Australia is the extent to which high volumes of intermittent generation will impact on the security and reliability of the network.

The issue has been of principal concern to the government of South Australia. South Australia already has on a regional basis one of the highest concentrations of wind powered generation anywhere in the world (about 17%). This compares with approximately 2% elsewhere in the National Electricity Market (NEM). South Australia is also relatively thinly connected to the rest of the NEM, so it presents a good case study for assessing the impacts of a high volume of wind generation on the transmission network.

The National Electricity Market

The NEM operates as a sealed bid multi-round auction, with dispatch of generators based on the prices offered.[16] Generators sell their energy into the NEM in competition with other generators, based on their price/volume offers, while retailers purchase energy on behalf of consumers. The process of supply and demand matching is centrally coordinated by a system operator, the Australian Energy Market Operator (AEMO).

AEMO uses a variety of forecasting tools to determine the level of demand for every dispatch interval in the NEM and then uses the supply curve of generator offers, stacked in order of price, to meet demand.

Offers are submitted every five minutes of every day and spot prices are determined half hourly (the average of six five minute prices). Initial offers for dispatch are usually made by 12:30 pm the day before. These are then matched to a day-ahead forecast of demand by AEMO to provide a preliminary view of supply and demand outcomes and associate prices. However, generators can then subsequently change their offers right up until five minutes before actual dispatch.

There is a market price cap of A$12,500 MWh (A$ - Australian dollars) and a price floor of -A$1000MWh. AEMO also has responsibilities for managing power system security and supply reliability, coordinating national transmission planning and developing the market.

Current NEM arrangements

High penetrations of intermittent renewable generation such as wind can impose significant impacts on the transmission system. However, the NEM has some inherent strengths and flexibility in managing such fluctuations. It is an electricity only market operating under a bid-based security constrained dispatch, which co-optimises the costs of meeting demand and maintaining system frequency.

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[16] See “An introduction to Australia’s National Electricity Market” published by AEMO for more detail, available at http://www.aemo.com.au/corporate

Market prices are calculated every five minutes, which allows generators to respond quickly to market signals to correct imbalances caused by intermittency (for example gas and hydro generation). Thus the flexibility required in meeting the challenges of intermittent generation is in large part met through the five by five minute energy market itself.

AEMO also procures a range of system 'balancing services for managing variations within five minute operational timeframes. This is done through a set of Frequency Control Ancillary Services (FCAS) markets that operate in parallel to the primary market for energy. FCAS maintain the frequency of the electricity system within required limits (the Australian standard is 50 Hz) by ensuring that total generation matches total load in real time.

There are separate markets for FCAS depending on the type of balancing service offered and the different time frames over which particular generators can or are willing to respond to provide these services. Small frequency fluctuations are handled through 'regulation' FCAS and large frequency disturbances, with the potential to threaten system security, are handled through 'contingency' FCAS. If insufficient FCAS services are available, AEMO manages dispatch processes to constrain generation and network flows to ensure power system continues to operate in a secure manner.

The intermittent nature of wind powered generation primarily affects the need for regulation services required to manage small frequency deviations around 50 Hz. These services are generally procured from generators with Automatic Generation Control (AGC) capability. This capability (often a feature of large baseload thermal generators) allows frequency fluctuations to be corrected in real time. Under the current 'causer pays' cost allocation arrangements in the NEM the cost of regulation FCAS are split between generators and customers, and wind generators are required to fund these costs based on their contribution to frequency deviations.

Recent NEM reforms

There have been some important recent developments in NEM dispatch arrangements to accommodate increasing levels of wind generation.

In particular, in 2008 the NER were changed to allow wind generators to be integrated into the NEM dispatch process. This allows them to be controlled by AEMO when constraints bind, and importantly, also allows their contribution to the need for balancing services to be recognised in subsequent cost allocation.

A further critical reform from a national perspective was the implementation of a new centralised wind energy forecasting system in the NEM in 2008, which is continually being refined. This forecasting system uses a combination of real time measurements, historical information, weather forecasts, terrain data, and turbine availability to forecast and publish wind generation from five minutes ahead to up to two years ahead (60 minute resolution), with capability for identifying daily wind patterns for individual wind farms.[17]

[17] For a description see http://www.aemo.com.au/corporate/0057-0030.pdf

South Australia

Despite the more general reforms for handling intermittency in the NEM outlined above, the South Australian government was concerned that the much higher penetration of wind generation in its state relative to other states in Australia could potentially affect network security. It commissioned a study by the state Electricity Supply Industry Planning Council (ESIPC) in 2004 to assess this risk and possible options for managing it.[18]

ESIPC identified two principal impacts that were not well addressed under current arrangements. First, the voltage on the electrical network must be maintained within specified tolerances, which can be managed through the reactive power capability of generators. ESIPC found that more conventional forms of wind generation, compared with fossil fuel generation, did not have sufficient capability to provide reactive power, potentially threatening system security under high levels of penetration. Second, because wind generators are generally of small size they provide little system inertia.

Consequently large levels of wind penetration can lower the level of inertia in the system, which increases the impacts of frequency fluctuations and the costs of FCAS required for managing it.[19]

The concern raised by ESIPC is that once the penetration of wind farms reaches certain levels and over time displaces existing generation capacity this increases the costs of regulation FCAS, in particular, as well as leading to an overall reduction in voltage support provided to the network. The prospect of wind generation substantially increasing regulation FCAS costs over time is now an issue of more general concern in the NEM, and is currently being investigated by the national market operator AEMO. Fortunately Australia operates markets for FCAS which should help keep these costs down from a total system perspective (that is, as the value of such services increase, this should attract new entry for the provision of such services). Currently FCAS make up only a few per cent of total energy costs in the NEM. However, under 'causer pays' arrangements which operate in the NEM, these costs would fall disproportionately on wind generators. Thus while any increase in FCAS costs is likely to remain manageable from a system wide perspective, they could be much more significant from the perspective of renewable generators (and be seen as a future barrier to entry).

Strengthening connection standards through special license conditions

ESIPC suggested that many of the issues identified above could be addressed through strengthening of generator technical standards in South Australia. For example, wind generation can be fitted with reactive power equipment such as SVC and other control equipment to: significantly improve their ability to produce or absorb reactive power when

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[18] Energy Supply Industry Planning Council, "Wind report to ESCOSA" April 2005, available at: http://www.escosa.sa.gov.au/Projects/17/2005-wind-generation-licensing.aspx

[19] The inertia of available generation capacity provides resistance necessary to maintain system frequency after power system disturbances.

required; smooth their level of output (reducing variability); and ride through system faults to help manage the impacts of lower system inertia. Moreover, wind generation technologies are evolving rapidly around the world and many of the newer variable speed wind generators coming onto the market, such as doubly fed induction generators (DFIGs), are able to provide some of these capabilities without the addition of specialised equipment.[20]

Generator technical standards in the NEM are typically developed and enforced at a national level. To date these have not required intermittent generators to have the same level of technical capability as other larger conventional generators because of their generally much smaller size and volume within the NEM more generally. With increasing penetration levels in some states, primarily South Australia, as well ever increasing size of wind turbines, this is now becoming a more important issue. However with widely varying penetration levels among different states of the NEM, there has been little push to impose higher technical standards, and thus additional costs, on renewable generators at a national level.

States are responsible for licensing energy market participants, and the South Australian government sought this route to circumvent national legislative change process. It introduced a number of new technical requirements for generators, on the basis of ESIPC recommendations, as a condition for obtaining a new generator licence in 2005. These were reviewed and subsequently reaffirmed in 2010[21] and require renewable generators to:

- Have the ability to remain connected to the system and ride through faults; and
- Be able to smooth short term fluctuations in output; and absorb and produce reactive power.

These standards are now considered to be consistent with global best practice. However, at this stage they only apply to new wind generation connecting in South Australia. It is likely that connection standards elsewhere in the NEM will also come under review as wind penetration levels increase in other states.

2.6 Case study 4: The integration of renewable energy in Europe

These are enshrined in a set of measures known as the Climate Action and renewable energy package (or Green Package)[22] which sets CO_2 reduction targets across all sectors of the economy and energy efficiency targets, and requires Member States to meet 20% of Europe's energy needs from RES by 2020.

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[20] Impact of Large Scale Wind Power on Power System Stability. Ch. Eping, J. Stenzel, M. Poller, H. Muller. DIgSILENT Consulting available at: http://www.digsilent.de/Consulting/Publications/PaperGlasgow_DIgSILENT.pdf

[21] Essential Services Commission of SA, "Licence Conditions for Wind Generators – Final Decision", May 2010, available on www.escosa.sa.gov.au

[22] The 'Climate and Energy package' was agreed by the European Parliament and Council in December 2008 and became law in June 2009. More information is available here: http://ec.europa.eu/clima/policies/package/index_en.htm

Integrating the growing number of intermittent and distributed generation sources into existing electricity networks and markets in a technically sound and cost-effective way is challenging. This is primarily because power flows in networks can become difficult to predict and control as many intermittent and distributed installations feed into the system. The EU targets will have a significant impact on Europe's generation mix, and potentially on wholesale market arrangements and grids.

The implications of these targets are all the more far-reaching because the EU's electricity and gas markets are fragmented along national lines or clusters of Member States. Interconnections between Member States are often too limited to allow electricity to flow seamlessly across the EU. As surplus RES are often located in areas that are away from high demand centres, this fragmentation limits the levels of renewable energy that Member States can accommodate. It also reduces the extent to which countries can contribute beyond their borders.

Therefore, reaching the environmental targets set out in the Green Package would be eased by the creation of a single European electricity market, and the construction of a pan-European electricity grid. A truly integrated market would facilitate optimal trade and allow electricity flows from areas of surplus such as the North Sea.

Creating such an integrated market is the aim of a set of EU laws called the Third Internal Energy Package (Third Package),[23] which was adopted in 2009. The Third Package builds on a series of previous reforms aimed at integrating and liberalising the European national energy markets that started in the early nineties.

It gives powers to European energy regulators and TSOs to draft the operating rules that will lead to the integration of the national electricity and gas markets and enable them to accommodate growing levels of renewable energy generation.

This part of the report will present the European context and highlight the main regulatory obstacles to the integration of electricity from RES (and in particular from wind) in the EU, and present the solutions that are being devised at European level. It will also provide case studies to describe measures that European regulators have adopted at national level to address issues that are not regulated by the Third Package and remain under the responsibility of Member States.

The case studies will focus on the impact of renewable generation on market arrangements and on conventional generation capacity, and present the solutions that are being devised in Germany, Italy, Spain and the UK.

[23] Information on the Third Package is available here:
http://ec.europa.eu/energy/gas_electricity/third_legislative_package_en.htm

The European Union context

The Green Package requires EU Member States to reduce their greenhouse gas emissions by 20% below 1990 levels, improve their energy efficiency beyond a business as usual projection by 20%, and produce 20% of its gross final energy consumption from RES by 2020.[24] The renewable energy target covers electricity, heating and cooling. It is expected that Member States will need to double their share of electricity from renewable sources to 30% in order to reach the overall target.

The target has been broken down into national targets, determined using a methodology that included a flat rate increase in generation from RES of 5.5% for each member state and an additional increase based on each member state's GDP per head.

These national targets vary from 10% for Malta to 49% for Sweden. Some Member States, such as Cyprus, Luxembourg, Malta and the UK are facing a greater challenge than others, because they currently produce a very low share of their energy from renewable sources and have accepted ambitious targets that reflect their renewable energy generation potential and relatively high GDP per head. The targets take into account the effects of energy efficiency and energy saving measures in the period 2010-20 expressed in terms of gross final energy consumption.

The Green Package proposes several measures to ensure that Member States reach their targets. For example, member states must provide either for priority or guaranteed access to the grid system, and priority of dispatch for electricity produced from RES, subject to requirements relating to the maintenance of the reliability and safety of the grid.

They can statistically transfer an amount of non-renewable energy to another member state in exchange for an equivalent amount of renewable energy, set up joint projects for the production of electricity and heating from renewable sources, and purchase renewable energy from countries outside the EU.

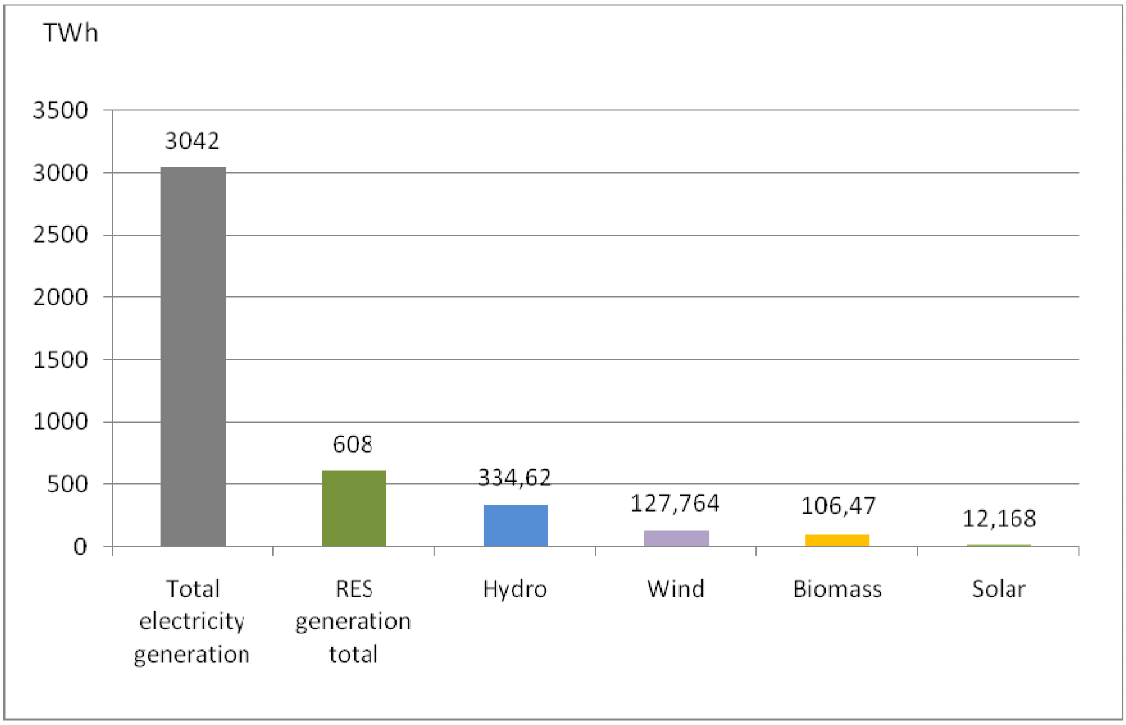
To ensure traceability and authenticity of renewable generation, member states are also obliged to guarantee the origin of electricity, heating and cooling produced from RES.

In 2009 around 19.9% (608 TWh) of the total net electricity generation came from RES. Hydro power contributed the largest share with 11.6% of the total EU generation. The generation from intermittent wind and solar power accounted for 4.2% and 0.4% respectively. Biomass contributed a 3.5% share.

Figure 1: EU27 electricity generation mix by energy sources in 2009

[24] Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources. Available at: http://eurlex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0016:0062:EN:PDF

For a general overview of the Green Package see also: http://ec.europa.eu/clima/policies/brief/eu/package_en.htm



Source: European Commission Joint Research Centre, Renewable Energy Snapshots 2010

Wind energy represents the greatest share of new renewable generation being developed in the EU over the past 10 years, and it is projected to retain this position for the next few years. In 2009, wind power alone accounted for 39% of all new European energy capacity installed.[25] The development of solar power has also shown some promising progress. In 2009, photovoltaic accounted for 17% of all new capacity installed in Europe, exceeding the amount of new generation produced through all conventional energy sources other than gas.[26]

According to the latest projections, Europe is on track to achieve the 20% energy consumption from RES target. It is estimated that 20.7% of energy consumption and 34% of electricity demand in Europe will be met by RES. In addition, the European Commission expects 64% of new energy capacity installed in the decade from 2011-20 to come from renewables. Wind power would account for 41% of all new installations.[27]

Obstacles to integration of renewables

The European market is fragmented, both along national borders and around clusters of member states. The current market lacks both physical interconnection and a harmonised

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[25] "Wind in power 2009: European statistics", EWEA. Available at: http://www.renewableenergyfocus.com/_virtual/article-downloads/Full%202009%20stats%20from%20EWEA_a7092.pdf

[26] Source: http://www.rethinking2050.eu/fileadmin/documents/ReThinking2050_full_version_final.pdf

[27] Source: 'EU energy trends to 2030', European Commission

regulatory regime across the continent. Increasing the share of renewable energy beyond the 2020 targets will be eased by the creation of a fully liberalised and integrated internal European electricity and gas market.

The existing market design rules across Europe have been optimised to the needs of conventional generation. This means that the way electricity is traded domestically and cross border does not always take specific account of RES. This is particularly evident when one looks at capacity allocation, network arrangements and grid connection rules.

Currently, most of the capacity allocation in Europe takes place in day-ahead and forward markets. As a result, variable renewable generation is at a disadvantage as it is not possible to predict its output accurately a day-ahead and even less further in advance. In addition, GCTs in around half of the EU27 are still more than 5 hours before real time delivery (see Graph 2). Because renewable energy generators cannot predict their outputs accurately far in advance, could expose them to high imbalance risks.

Differences in GCTs across Europe, which vary from 24 hours to 1 hour, could also prevent generators from trading electricity cross border. Even if there were interconnector capacity available within the intra-day timeframe, substantial differences in the timings of gate closure times in two adjacent control areas (Member States) could make trading complicated for the renewable energy generators. Currently, there is very little capacity available intra-day and differences in non-harmonised GCTs could significantly reduce cross border trading options for generators (including RES) on an intra-day stage. The example of Italy and France, two adjacent member states whose intra-day market periods differ in length substantially, illustrates the point. The country with a shorter GCT and a longer intraday market (France in this case) could not always transport its surplus electricity cross border (to Italy in this case) due to different timings as the adjacent market with a shorter intra-day period could be already closed.

Figure 2: Time between closure of forward market and real time delivery across Europe

Source: C09-SDE-14-02a, 'Regulatory aspects of the integration of wind generation in European electricity markets,' CEER public consultation, 2009

The network arrangements across Europe vary largely amongst Member States and were not developed to accommodate high levels of renewable generation.

In most Member States there are no tailor made grid connection rules setting out specific operational requirements for renewable generation, for example on behaviour during system disturbances, reconnection following outages or provision of system services.

This lack of harmonised rules that cater for the specific characteristics of intermittent renewable generation can result in insecure, uncoordinated and sub-optimal system operation.

This risk is being further exacerbated by the growing levels of (intermittent) generation connected directly to distribution networks.

A major blackout in November 2006, which affected more than 15 million European households,[28] highlighted some of the limits of the existing system:

- TSOs operate the system closer and closer to its limits due to significant difficulties in building new overhead lines;
- There is poor coordination among national TSOs and among TSOs and DSOs; and
- In some Member States dispatchers have only a limited range of action available to for handling grid congestions.

[28] https://www.entsoe.eu/fileadmin/user_upload/_library/publications/ce/otherreports/Final-Report-20070130.pdf

The current practices of TSOs need to be updated and a new approach to system operation must be developed. This new approach ought to take into account the specific characteristics of renewable energy and distributed generation so that TSOs would be aware of these generators in the system (in particular those connected to the distribution networks). In addition, the system should allow TSOs to use renewable energy and distributed generation to provide system services during both normal and disturbed system operation, when it is economically efficient to do so.

Grid connection and use of system charges are not specifically designed for renewable generation and therefore also hinder integration of renewables. In many cases charging methodologies are only cost-reflective for conventional generation and do not take into account the variable nature of renewable generation. As a result, renewable generators have to pay for capacity based on their maximum generating capacity rather than for the transmission capacity they actually use. Only four regulatory regimes in Europe distinguish variable generators and have separate charging methodologies developed for renewable energy.[29] This lack of attention to specific characteristics of renewable generation results in higher costs of its outputs, and therefore reduces its competitiveness against conventional generation.

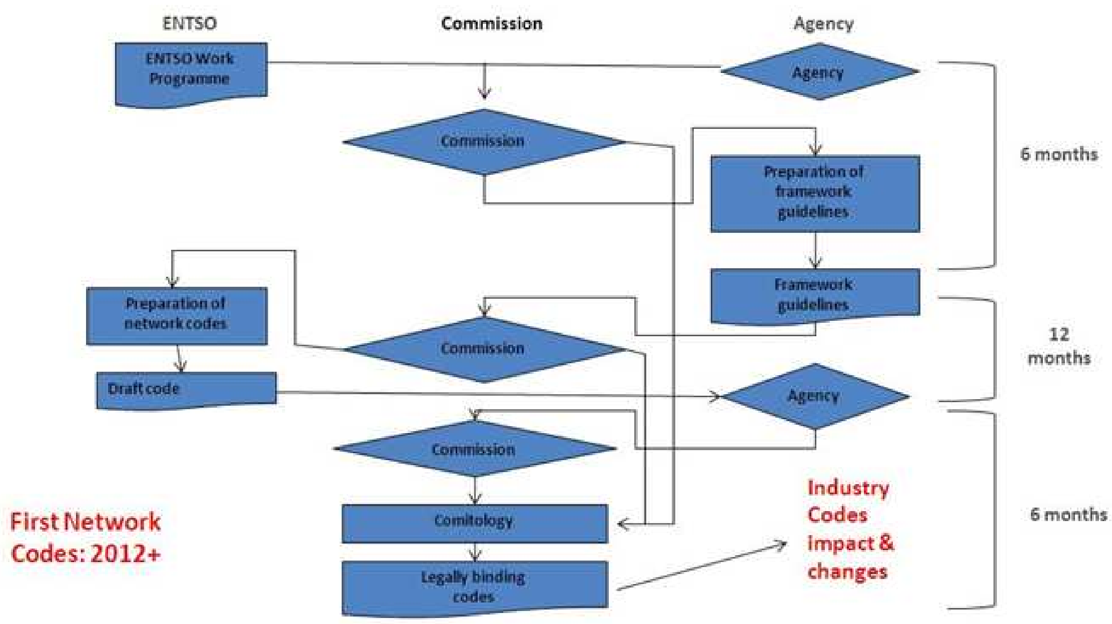
Hence, the existing charging methodologies across Europe should be transparent and cost-reflective to ensure that there is no undue discrimination against specific types of generation. System charges should also provide sufficient incentives for generation in choosing where to locate and to guarantee an appropriate balance of risk and cost to the various market players.

Solutions included in the Third Package

The Third Package sets out measures to address many of the issues mentioned above. Although its remit goes beyond accommodating the increasing share of renewable energy, it tackles regulatory obstacles that are either directly or indirectly hindering the integration of RES. The Package will harmonise regulation on all key aspects of electricity (and gas) markets and network arrangements, such as grid connection, capacity allocation and congestion management through European framework guidelines and legally-binding network codes. The framework guidelines, which will not be legally binding, will set out high level harmonised requirements, whereas the network codes will specify in more detail the requirements of the framework guidelines. The newly created European Agency for the Cooperation of Energy Regulators (ACER) will draft the framework guidelines. The European TSO organisations for electricity (ENTSO-E) and for gas (ENTSO-G) will propose draft network codes to the EU institutions which will develop them into legally binding codes.

[29] C09-SDE-14-02a, ‘Regulatory aspects of the integration of wind generation in European electricity markets,’ CEER public consultation, 2009

Figure 3: Framework guidelines/network codes approval process[30]



Source: Ofgem

On 20 July 2011 ACER[31] adopted and submitted to the Commission the framework guidelines on Electricity Grid Connections. The framework guidelines are based on European Regulators for Gas and Electricity Group's (ERGEG's) Pilot Framework Guideline on Grid Connection, adopted on 7 December 2010 and on the related initial impact assessment.

Grid connection covers all issues to establish and to maintain a physical connection between the transmission and/or distribution grid and the grid customers. They require subsequent network codes to develop minimum standards for all grid users, providing a framework to maintain system security, availability and the proper functioning of the electricity market from a technical point of view.

The framework guidelines also acknowledge the growing share of variable renewable generation. As a result, it requires grid connection network code(s) to outline grid connection rules for specific grid users, which include renewable and distributed generators. Regarding variable generation, the guidelines establish standardised and flexible connection requirements for large scale variable generation to mitigate the specific problems affecting

[30] Commission stands for the European Commission, a European Union institution that proposes European legislation to the Member States and the European Parliament, is responsible for ensuring EU law is applied throughout all Member States and for the daily running of European policies and funds.

[31] Agency stands for ACER, the Agency for the Cooperation of Energy Regulators

system stability. With respect to distributed generation, the guidelines ask network codes to define standardised, broad and non-discriminatory technical requirements, concerning bi-directional flows and changed patterns of flows between transmission and distribution. These codes will ensure distributed generation connections are developed in a consistent and efficient way across the EU.

These two measures should provide clearer rules defining renewable energy and distributed generators' behaviour in the system. They should significantly reduce the system operation risk caused by growing amounts of renewable energy generation. In addition, the framework guidelines require the related grid connection network code to set out procedures and requirements for the exchange of information between TSOs and DSOs. This should ensure that TSOs are aware of levels of renewable and distributed generation connected directly to the distribution networks, and therefore further increase the security of system operation.

Other framework guidelines, e.g. Capacity Allocation and Congestion Management (CACM), System Operation or Balancing, tackle a number of market design issues and cross border trade in general.

The guidelines provide for harmonised capacity allocation mechanisms across Europe that should introduce more efficient use of cross border interconnections to reduce congestion. For the day-ahead time-frame, the CACM framework guidelines require the subsequent CACM network code(s) to establish capacity allocation mechanism based on implicit auctions.[32]

Regarding forward markets, network codes will set out a Use-It-Or-Sell-It mechanism that will allow the freeing of unused capacity for day-ahead trading. The framework guidelines also acknowledge the growing share of renewable energy and require the subsequent network code to establish an efficient intra-day market mechanism that uses implicit auctions for capacity allocation. This creates scope for further integration of RES as it provides for conditions to trade as close to real time as possible. Overall, these measures should facilitate electricity trade across Europe and provide for a more favourable intraday trade market for renewable integration.

More framework guidelines and network codes will have to be developed to fully integrate and harmonise the European energy market. The guidelines and codes yet to be developed will cover the remaining key market and network design areas such as data exchange and settlement, interoperability, transmission tariffs, transparency etc.[33] However, these measures will take some time to develop and implement. The full set of network codes are expected to be finalised by 2014. In order to become legally binding these codes will then

[32] Implicit auction – an auction at a power-exchange whereby capacity is implicitly sold together with a volume of electricity traded via interconnector.

[33] For full list of electricity FGs, please refer to: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_ACTIVITIES/Input_to_Framework_Guidelines/Electricity

have to be approved by the European Commission and the Member States.[34] Therefore, although coordinated action is being taken to harmonise the European market and support integration of renewable energy, in the interim, Member States will have to tackle the challenges mentioned above at a national level.

2.7 National solutions

We have produced two case studies to compare challenges and solutions adopted by some member states at national level to address issues that are not, or not yet, covered by European legislation. We have identified two main areas:

- The implications of variable renewable generation for market design, including the balancing market; and
- Initiatives undertaken by national regulators to provide back-up generation capacity.

In this chapter we will focus on the first point. Initiatives undertaken by national regulators to provide back-up generation capacity will be addressed in Chapter 3.

The implications of market design and system operation arrangements on renewable energy in Europe

Current market arrangements were created mainly to accommodate generation from conventional sources. The increasing deployment of renewables will inevitably cause challenges to the system. Therefore, the market design will need to change significantly in order to adjust to a significant change in generation mix. This section presents an overview of practices adopted by the national regulatory authorities of Germany, Italy, Spain and UK with respect to:

- GCT arrangements to accommodate renewable energy;
- cross border capacity allocation (in particular with reference to intra-day markets);
- balancing obligations on renewable energy and the role of the TSO in balancing;
- centralised or decentralised systems to forecast non-programmable renewable energy generation;
- provision of network/system services by renewable energy installations in order to react to both changing meteorological and grid conditions; and
- TSO's orders to reduce wind production.

[34] The Framework Guidelines and the network codes will be approved through the so-called " comitology process", a legislative procedure involving the European Commission, the Member States and, to a lesser extent the European Parliament, which is designed to set out and approve EU-wide implementing legislation. For more information see: http://www.eurofound.europa.eu/areas/industrialrelations/dictionary/definitions/comitology.htm

Gate closure time arrangements to accommodate renewable energy

In April 2005, **Great Britain** introduced the British Electricity Trading and Transmission Arrangements (BETTA) in England, Wales and Scotland.[35]

This relates to bilateral trading between generators, suppliers, traders and customers. Electricity is traded in half-hourly blocks which could also help renewable generators as they only have to forecast generation for a short period of time.

Since 2002 Great Britain has had one of the shortest GCT in Europe, one hour ahead of real time.

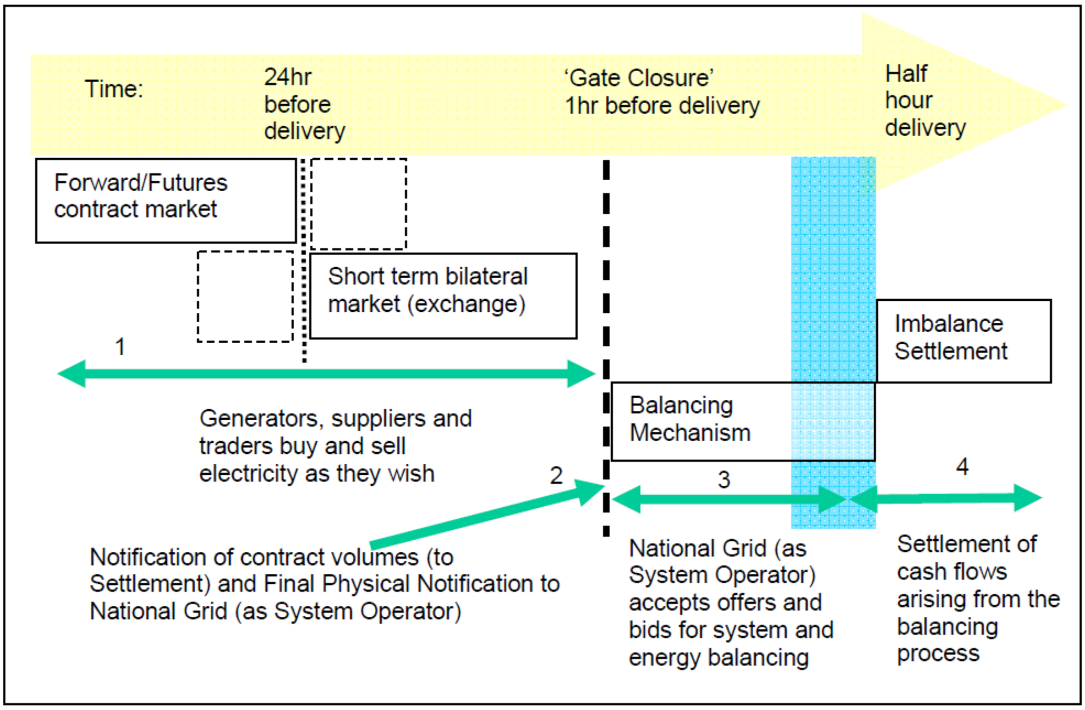
This enables wind generators to forecast their outputs closer to real time; they are therefore more likely to be able to meet their forecast generation levels.

Generators are then less exposed to imbalance risks, as they can have a more accurate forecast of what they will generate in one hour's time compared to the 3.5 hour gate closure previously used.

Figure 4 shows the current electricity market arrangements in GB. Under BETTA, generators need to submit their Initial Physical Notifications (IPNs) at 11am at the day-ahead stage to inform National Grid of planned net physical flows onto and/or from the system. Bids and offers, and Final Physical Notifications (FPNs) are accepted up until one hour before delivery, which is when the balancing mechanism starts to operate.

[35] Northern Ireland has separate arrangements and is not part of Great Britain. The Central Design Authority is responsible for coordinating and supporting the overall design of Retail Market Arrangements in Northern Ireland. More information on BETTA is available here: http://www.nationalgrid.com/uk/sys_09/default.asp?action=mnch10_2.htm&Node=SYS&Snode=10_2&E=Y

Figure 4: Gate closure system in the UK



In **Germany** the GCT for the day-ahead market at the principal energy exchange in the country is at 12:00 pm (CET). At this time a daily auction takes place. The results of the auction are made available from 12:40 pm.

The GCT for the intraday market is 45 minutes before the beginning of the delivery. The electricity of the intraday market is traded continuously, with no auctions taking place. Starting at 3:00 pm on the current day, all hours of the following day can be traded on the intraday market. Orders on the day-ahead and intraday market can be made for individual hours or blocks. In September 2011 it was decided to introduce 15 minute products on the intraday market.

On 1 December 2010 the TSOs shortened the time required for the notification of power supply through their networks from 45 to 15 minutes.

This new arrangement is seen as a precondition for a better integration of renewables in the electricity markets.

GCT arrangements in place in **Italy** for the day-ahead and intra-day market are summarised in the following table.

Table 1: Gate closure time arrangements in Italy

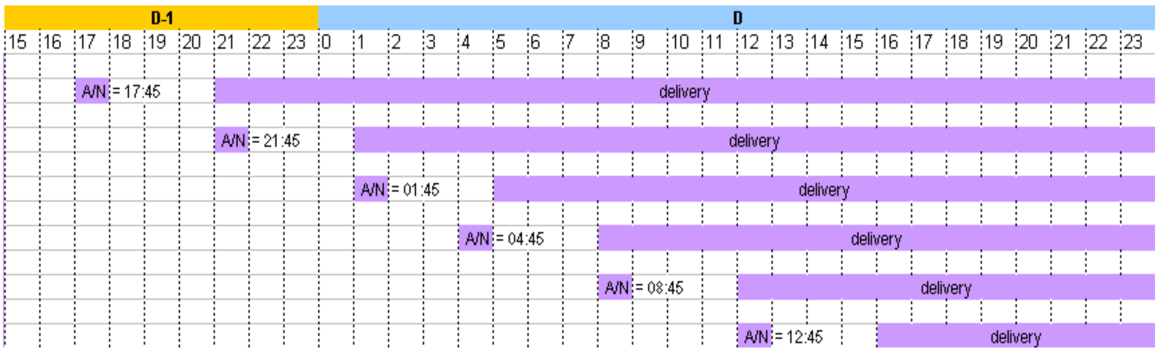
	Session	Closing (time, date)	Tradable hours in the delivery day (D)
Day-ahead market		09:00, D-1	00:00 – 24:00
Intra-day market	Session 1	12:30, D-1	00:00 – 24:00
	Session 2	15:30, D-1	00:00 – 24:00
	Session 3	07:30, D	12:00 – 24:00
	Session 4	11:30, D	16:00 – 24:00

There are no special GCT provisions to accommodate intermittent generation. This is mainly due to the existence of exceptions to market provisions which are allowed on dispatching and balancing rules. These will be described in the following sections.

In **Spain**, the day-ahead GCT of the Iberian Electricity Market (MIBEL) is at 10.00 am. A proposal is currently under discussion to move the closure of the MIBEL to 12.00 pm in order to pave the way for market coupling with Central West Europe.

After day-ahead gate closure, the generators (and buyers) can adjust their programs in the intraday markets. MIBEL holds six intraday auctions (approximately one every four hours) where energy is negotiated for delivery starting 3 hours and 15 minutes after the closure of each auction (and delivery closing in the same day).

Figure 5: Gate closure time arrangements in Spain



This means in practice that intermittent renewable energy generators can update their programs a maximum of seven hours before delivery (there is one auction every four hours and the delivery starts 3 hours and 15 minutes after each auction). Although seven hours allow for relatively precise forecasts for solar and wind generators, it would be desirable to have intraday GCT near to the real time in order to adjust the wind and solar power production.

Cross border capacity allocation (in particular with reference to intra-day markets)

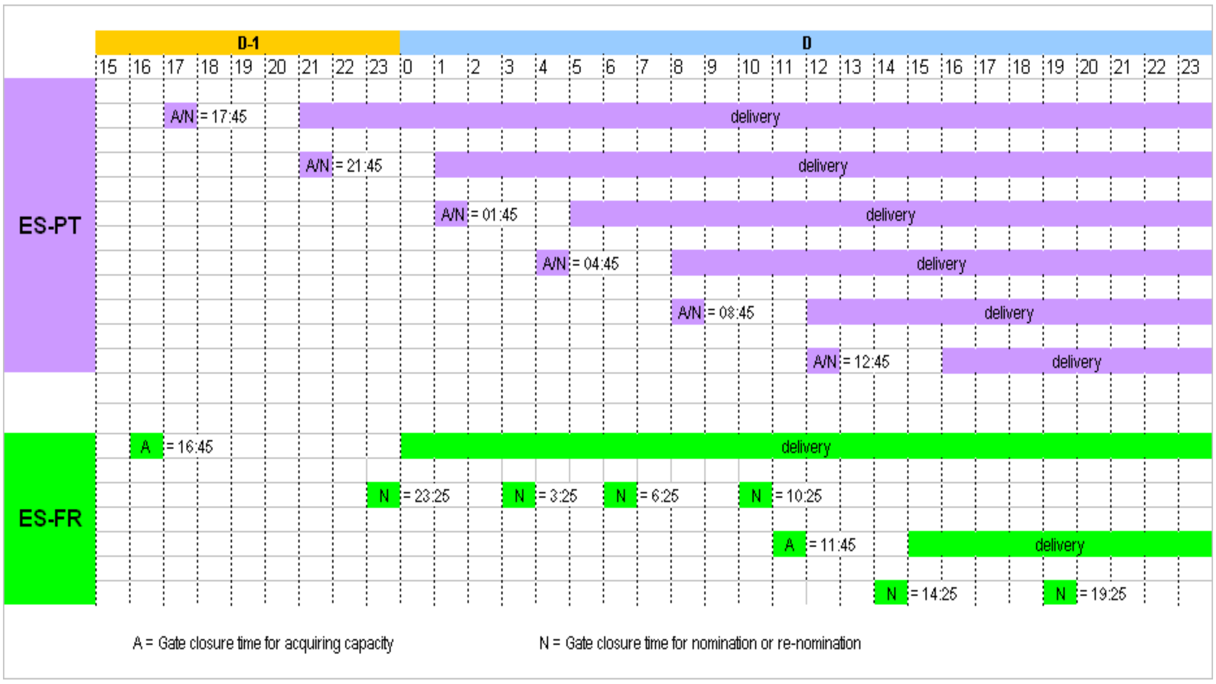
In **Spain** cross border capacity allocation procedures are in place with respect to interconnections with Portugal and France.

Market splitting operates on the Spain Portugal interconnection. It is implemented in the day-ahead market and through the six intraday implicit auctions. Regarding the Spain-France interconnection, there are currently one day-ahead explicit auction and two intraday explicit auctions (Table 2). GCT for cross border capacity allocations between Spain and adjacent countries are reported in Figure 6.

Table 2: Cross border capacity allocation between Spain and adjacent countries

	Number of intraday auctions	Number of intraday nomination deadlines	Compensation for curtailments of allocated capacities	Compensation for curtailments of nominated capacities
France – Spain Spain – France	2	6	Held capacities physically firm	Nominated capacities physically firm
Portugal – Spain Spain – Portugal	6 (implicit)	6 (implicit)	NAp. Programmed exchanges physically firm	NAp. Programmed exchanges physically firm

Figure 6: Gate closure times for cross border capacity allocations between Spain and adjacent countries



It has been observed that explicit auctions do not represent an efficient mechanism on these interconnectors. Explicit auctions result in a loss of social welfare which could be avoided through the additional implementation of implicit allocation.[36]

Auctions on both interconnections allow increasing evenues for cross border capacity allocated within the day (as in the day-ahead stage).

In **Germany,** there are no standardised GCTs for cross border capacity allocations between Germany and all adjacent countries; instead there are different GCTs for each cross border capacity allocation.

Balancing obligations on renewable energy generators and the role of the TSO in balancing

Balancing obligations on renewable energy largely differ among countries. In **Italy**, electricity produced from renewable sources, has priority dispatch.

They run immediately after the so-called ‘must-run units’. This means that, under normal system operations and as far as there is sufficient load demand at the national level, renewable power must be dispatched.

[36] See regional reports on interconnections use and management: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI/South-West/Final%20docs

The TSO[37] can require wind generators to reduce the instant power production in two situations: when the demand/load is low or null (with respect of the priority dispatch principle) and for system security reasons. The percentage of wind power over the base load demand is very low. Therefore the first case does not really happen and dispatching orders to reduce production are limited to planned grid operation and management activities or to very special situations related to system security (e.g. real time orders due to physical limits of the network).

At present, intermittent generation does not have any obligation concerning balancing. The costs sustained by the system to purchase ancillary services related to wind unbalances are fully socialised. Due to the reasons mentioned above wind power producers have no market signals in respect to any delivery program.

In **Great Britain**, generators self-despatch their plants rather than being centrally despatched by the System Operator. This means that generators have control over the amount that they generate as they tell the TSO the amount of electricity they are going to produce. There are incentives for generators to balance their own position if they choose to participate in the Balancing Mechanism. Participation in this mechanism involves submitting 'offers' (proposed trades to increase generation or decrease demand) and/or 'bids' (proposed trades to decrease generation or increase demand). The mechanism operates on a 'pay as bid' basis.

The generators also submit the price at which they are willing to reduce/increase their output (e.g. the price at which it would be cheaper to pay not to produce electricity as they have already sold the electricity regardless of what they produce).

The self-despatch mechanism avoids shutting down intermittent renewable generation for frequency adjustment reasons.

Due to low generation price, this is deemed to be uneconomical; a low load factor for generation from renewables is another reason why this would not be beneficial to renewables. Generators who do not meet their Final Physical Notification (the amount they wish to generate) can be penalised through imbalance settlement (cash-out).

Cash out costs are borne by those parties responsible for the imbalance of the system. This can be either paid at the System Buy Price (SBP) or sold at the System Sell Price (SSP) depending on whether electricity is being bought from or sold to the system. If a party helps the system by being imbalanced in the opposite direction to the system (e.g. generating

[37] Since 2005, the reunification of ownership and management of the national transmission grid has come into effect. TERNA SpA, the Italian TSO, owns almost all the national transmission grid, manages the transmission network and owns the necessary dispatching equipment. TERNA's main functions are those of a typical TSO. These include: i) responsibility for the energy dispatching and real time balancing of the electricity supply-demand, ii) security of the electricity delivery system, iii) managing of import-export interconnection lines, iv) grid connection of generating plants and consumers and v) responsibility for transmission network maintenance and development.

more when the system needs more) then the imbalance prices is the market price, thus more benign. The high variability and unpredictability of renewable generation means they could be more exposed to being penalised in the cash-out stage for not meeting their forecasted levels of generation, than in the case of conventional generation.

The UK government is currently contemplating a review of the cash out prices mechanisms to ensure that the cost of balancing the system is fully reflected in the cash out price. The costs that National Grid (the TSO) incurs when balancing the system are not currently fully reflected in the cash out price. Strengthening the imbalance signal through cash out reform will make the imbalance charge more severe. This encourages market parties to make more effort to balance their positions before gate closure. This, in turn, pushes up the spot price of wholesale electricity, which should ultimately be reflected in the forward markets. Forward prices are used by developers in investment appraisals, so higher forward prices increases the incentive for investment in generation – but not specifically in renewables. This approach could be more damaging for renewables, as it will make imbalance more expensive.

There are four options for reform that have been listed in the Electricity Market Reform consultation document. The first option is changing to a single cash-out price or one with a fixed spread between buy and sell. The second option is moving to more marginal pricing from the current ‘pay as bid’ scheme and making the imbalance price the average of the most expensive 500MWh of balancing actions. The third option is having more effective allocation of reserve contract costs; the costs associated with the SO purchasing Short Term Operating Reserve (STOR) are allocated using the previous year’s reserve usage for that moment. The plan would be to make these costs more closely aligned to the periods in which the reserve is actually used to enhance cost reflectivity. Finally, putting a price on currently non-costed SO actions. This would involve compensating customers for involuntary voltage reductions and power cuts and including these costs in the cash out price so these actions are properly reflected.

In **Germany**, according to legislative provisions, grid system operators must purchase, transmit, distribute and pay for electricity generated from RES. There is no restriction on building renewable installations (e.g. there is no limit on the renewable generation capacity that can be installed each year). Therefore all renewable installations have to be connected to the grid by the grid system operators, and renewable electricity may be fed into the grid at any time. There are no special balancing obligations on renewable energy.

Renewable energy installations are subject to feed-in management under very strict conditions. For example, renewable energy installations whose capacity exceeds 100 kW have to be provided with technical or operational facilities to reduce output by remote means in the event of grid overload.

Grid system operators are entitled to take technical control over renewable energy installations connected to their grid system with a capacity of over 100 kW if the grid capacity risks being overloaded on account of that electricity.

In light of the increasing number of renewable energy installations connected to the grid, these provisions are meant to support the safety of the network managed by the grid system operators.

In **Spain**, renewable generators are subject to the same balancing obligations as conventional forms of generation. Otherwise, large scale renewable deployment would not be possible due to operational risks linked to unpredictability of power output in the grid. Renewable generators must be incentivised (obliged) to be balanced.

Systems to forecast non-programmable renewable energy generation

In order to reduce unbalancing, the goal to improve forecasts of intermittent renewable power, including wind, can be pursued either by putting incentives, penalties and costs on generators, or by adopting a system level approach.

Wind generators may participate in the **Italian** electricity market pool only, selling the electricity they are going to deliver by presenting their production schedule for the following day. The gate closure of the day-ahead market in Italy is at 9:00 am. Therefore, the last chance wind generators have to communicate their binding schedule is very far from the time of delivery and this significantly affects the reliability of their possible forecasting.

Moreover, wind generators – as well as other intermittent renewable generators - are not responsible for their imbalances (imbalance charge applied to them equals the day-ahead market price) as the relevant cost is fully socialised. Yet, according to recently introduced legislation, they will be incentivised to invest in forecast tools as they can earn a bonus when their real production is in line with their injection schedule.

The TSO, instead, responsible for real time balancing, needs to assess in advance the total demand of the system and also the wind generators' output - together with the binding schedules deriving by the markets - and is able to perform this kind of analysis close to real time in order to balance the system.

So the directive adopted by the Italian regulator has been intended to minimise the system costs of wind unbalances by introducing an incentive (and penalty) scheme to push the TSO, who, unlike generators may operate close to real time, to perform better and better forecasts.

With a better forecast, in fact, the TSO may minimise the reserve capacity procured in the Ancillary Services Market[38] and the need for redispatching.

At present the wind generation forecast performed by the TSO is produced by means of neural networks applied directly to a number of selected plants and then extended to all the other ones.

In order to increase the reliability of production schedule presented by small wind generators, the state owned company (GSE) is required to forecast power production of intermittent renewable generating units (up to 10 MVA) at market zone level in order to prepare the injection programs for energy bidding in the day-ahead market. GSE is expected to implement a project for enhancing its forecasting activities that will provide the TSO with more reliable schedules.

In **Spain**, a weather forecast centre managed by the TSO has been created to deal with the uncertainty of renewable energy flows. The centre operates in a centralised way, and coordinates with 23 centres that provide real time information every 12 seconds. This data is processed to anticipate possible incidences that could appear regarding renewable energy so as to ensure supply reliability of the system. The availability of an efficient and well-functioning processing centre is particularly important for Spain due to its low levels of interconnection (which means that the system needs to be very well balanced, like an island).

Since 2010 **German** TSOs play a role as 'marketer' for electricity from renewable sources, in addition to their traditional activities. TSOs have to market all electricity produced by renewable energy installations for which electricity feed-in tariffs are paid. Marketing of this electricity means that the TSOs have to sell, themselves or jointly, all renewable electricity on the day-ahead or intra-day spot market of an electricity exchange. They have no discretion to decide when or if to sell the electricity. To cover the difference between their revenues and expenditures from 'marketer' activities (they are obliged to purchase all renewable electricity which receives a feed-in tariff) TSOs can claim the so called EEG-surcharge[39] from the utility companies.

[38] In Italy there is a specific market (Ancillary Services Market – MSD in Italian) where the TSO procures the resources that it requires for managing, operating, monitoring and controlling the power system (relief of intra-zonal congestions, creation of energy reserve, real-time balancing). In this market, the TSO acts as a central counterparty and accepted offers/bids are valued at the offered price (pay as bid). The Ancillary Services Market consists of a scheduling stage (ex-ante MSD with a gate closure at 5 p.m. D-1) and of the Balancing Market (MB). The MB takes place in five sessions (each starting at 11 p.m. D-1 and closing 1,5 hours before delivery). In order to select offers/bids presented by the operators at the scheduling stage in the Ancillary Services Market, the TSO carries out a number of programming activities; in particular it projects the wind output at market zone level on an hourly basis with respect to wind farms with nominal power higher than 10 MVA.

[39] EEG stands for Renewable Energy Sources Act. The EEG surcharge is passed on by the utility companies (suppliers) to final consumers to recover the costs for supporting the development of RES through feed-in tariffs.

The role as a marketer of renewable electricity is not typical for the TSOs. It is a pilot project based on a change of the German nationwide equalisation scheme which took place in 2010 and will be reviewed in light of experience. The Federal Network Agency (Bundesnetzagentur) had to create a report with suggestions to transfer the task of marketing to third parties by 31 December 2011. Therefore was is not yet clear if the TSOs will keep the role as a marketer of renewable electricity permanently.

At present, in Germany there is no centralised system to forecast non-programmable renewable generation. This function is carried out by several providers who offer short- and long term forecasts.

Some providers offer specialised weather forecasts relevant to the production of renewable electricity. For example, a specific branch of the meteorological service specialises in forecasting wind in certain regions to enable the optimisation of the forecast of wind generation in those areas.

TSOs develop their own forecasts based on the forecasts of several providers. A meta-forecast is developed by combining short and long term forecasts. TSOs' forecasts are published on the internet for the following:

- A day-ahead forecast of the expected wind generation is published on the transparency platform of the European Energy Exchange (the German power exchange);
- An online projection of the real wind generation (based on the current electricity feed-in); and
- A day-ahead forecast of the expected wind and solar generation and an online projection of the actual feed-in from wind and solar installations on a common internet page.

In **Great Britain**, the TSO forecasts likely levels of wind generation using historical outturn data and detailed local wind forecasts for 'visible wind farms' (ones with operational metering). There are six forecasts for the day (see Table 3) and each day 13 values are given, from 21:00 on the current day to 21:00 two days ahead. They calculate this from five wind speed forecasts per day that they receive from two forecasting companies. Elexon is responsible for the balancing and settlement code (BSC) for the GB network. It has detailed information on its website about GB electricity generation.[40]

[40] http://www.bmreports.com/bsp/bsp_home.htm

Table 3: British TSO forecasting schedule

Forecasts received		03:47	04:20	08:16	16:20	20:16
Forecast times	00:00	05:00	08:00	12:00	17:00	21:00

In GB, the grid code gives the legal framework for the TSO (National Grid) to obtain data from wind farms. There are several thresholds for this: England and Wales >50MW, South Scotland >30MW and North Scotland >10MW. Thresholds are lower for Scotland as a lot of GB wind generation comes from Scotland, due to higher wind speeds, and so it is important for the TSO to get more detailed information in order to produce more accurate generation forecasts. There is however embedded wind generation that connects to the distribution network and can be somewhat invisible to the TSO. This aspect makes the errors in National Grid's demand forecasts higher as it effectively lowers demand.

In the coming months there will be a shift to a new system. The new forecasting system uses three models: physical, statistical and an artificial neural network (learning algorithm). The physical model uses parameters of a new wind farm and is the basis for wind generation forecasting. After six to nine months it is possible to create a statistical model of a wind farm's generation. Only after one year of data can the TSO start training up an artificial neural network that uses past data to form new forecasts that should be more accurate than previous ones. All models still run together to generate three outputs for each forecast period. The previous few days of performance decides which model is used in the final generation forecast. This will be fully integrated into operational systems which will be able to analyse and refine the model's performance. Another advantage is that the new system gives probabilistic rather than deterministic forecasts (the old system gave the latter). This means that the TSO has probabilities of the generation being within a certain range.

The new system is being put into operation and there will be a period when the new and old systems will run in parallel, in order to extensively test the new system. Following this the connections to other operational systems will be enabled to allow forecasts from the new system to be made available.

Provision of network/system services by renewable energy installations in order to react to both changing meteorological and grid conditions

The **Italian** TSO did not require system services from wind power generators in the mid-1990s, when the first commercial wind installations were installed. This was due to a lack of technical solutions and to the low amount of wind energy produced. In subsequent years, in Italy as in many other countries, a technical debate emerged between the TSO and DSOs on one side and the wind industry and generators on the other. The discussion led to the publication, in 2004, of a national non-binding technical standard.[41]

Then, in 2005, due to the rising rate of wind plant installations, combined with the lack and slow development of the necessary transmission and distribution grids, the Italian regulator launched a consultation process regarding the evolution of priority access. Grid services have been investigated within this framework. The Italian regulator requested the TSO to carry out a survey to identify:

- the share of wind power installed in some market areas (Sardinia, Sicily and Central-South Italy) as a percentage of the base load and grid capacity; and
- the costs and timing to upgrade wind power turbines in order to enable the provision of grid services.

The survey covered 4, 490 MW of installed capacity, 116 plants and 48 producers; 18 stakeholders responded to the consultation. The results of the survey are summarised below:

Table 4: Results of a survey on network/system services provided by wind installations in Italy

	Upgrade costs for existing wind installations		**Time needed to implement the upgrade**	
	*Maximum (€/MW)**	*Average (€/MW)**	*Maximum (Months)*	*Average (Months)*
Power output modulation	7,984	4,318	18	9
Automatic remote cut-off system (operated by TSO)	8,133	3,794	18	7
Fault ride-through capability (LVRT)	38,754	25,176	12	5
Regulation of active power	1,250	1,000	3	2
Regulation of reactive power	26,738	5,374	18	5
Total	**82,859**	**39,662**		

* In 2007 prices

[41] Norma CEI 11/32.

Source: Italian Authority for Electricity and Gas

The survey highlighted the TSO's needs concerning grid services that should be required from existing and planned wind plants. It also emerged that only a few of the oldest wind plants could be upgraded with new grid service technologies: this range goes from 80% for the fault ride-through capability to almost 100% for the power output modulation.

Meanwhile, the TSO grid code was upgraded to include grid service requirements which should be applied to new installations made since mid-2008. In particular, the Italian regulator allowed grid operators (such as the TSO) to require new wind plants to provide some ancillary services for the benefit of the electrical system. These services could include power output modulation, cut-in power ramp control, fault ride-through capability and regulation of active and reactive power.

The debate over the upgrade of existing installations is still ongoing and mostly concerns cost allocation. These existing installations were set up at a time when wind generators were not required to provide grid services. The Italian regulator aims to find an efficient solution to upgrade wind plants when necessary and technically feasible. Costs will mainly be borne by final consumers, except for a small proportion (5% of the total amount) which will be borne directly by the TSO.

In **Spain**, non-programmable renewable energy providers can only participate in network services by decreasing their production when needed for operational security. Wind generators with more than 10 MW of installed capacity and solar PV generators with more than 2 MW of installed capacity are required to have immunity against voltage dips. Moreover, all renewable energy generators with more than 10 MW of installed capacity must follow reactive power instructions from the TSO in real time.

In **Germany** new wind generation units (commissioned after 30 March 2011) have to fulfil certain technical standards which allow the wind generation units to support the voltage and frequency stability. If these wind generation units do not fulfil the standards they will not receive a feed-in tariff.

TSO's orders to reduce wind production

As the penetration rate of wind produced electricity grows, the need for decision making tools becomes particularly relevant as TSOs have to bear considerable additional costs to balance the system. At the same time, the transmission infrastructure is often unfit to cope with the substantial increase in wind generation which we are witnessing in many Member States. As a result, under some circumstances TSOs are unable to accept all the power generated by wind turbines and have to request a reduction in wind production.

In **Italy**, since 2009 TSOs have made a significant number of requests to wind generators to control and reduce their wind production, in spite of the priority despatch principle in place for renewable sources. These requests came mainly from the lack of grid infrastructure where the wind blows. Estimates show that, for the above reasons, wind production losses in 2010 amounted to around 130-140 GWh, corresponding to about 2% of the annual wind power production.

In order to tackle this critical issue, the Italian regulator required the SO to develop a computational system to determine the amount of energy which wind farms avoided generating in order to respect dispatching orders from the TSO. On this basis, the TSO refunds wind generators for the electricity they were unable to produce. The cost of the refund is passed through to consumers. The generators can apply for the refund if they respect a 'reliability index' which measures the ability of the generator to respect dispatching orders by the TSO. The refunds amounted to about €10m in 2010.

Conclusions

These examples demonstrate that individual Member States are making progress on adapting market arrangements to better integrate renewable energy generation. Although the approaches taken are in each instance fine-tuned to suit each country's individual situation, lessons can be learned from and by each Member State. This will lead to a more homogenous approach, which in turn enables the creation of a single European energy market.

2.8 Case study 5: The integration of renewable energy in New England (USA)

In the USA the decision to impose renewable energy requirements and goals is left to individual states.

Approximately 36 states currently have some form of renewable energy requirement or goal, with policies varying considerably by state.[42] In general, such states require their utilities to ensure that a percentage of the utility's load is met through new renewable energy.

The utilities are then responsible for either building renewable generators or purchasing renewable power (or renewable energy credits) from merchant generators.

In several areas of the USA the purchase and dispatch of electricity is done through a regional market. Typically, a group of states will participate in a common, regional market; however, a handful of larger states (such as California, Texas and New York) have markets that coincide with the political boundaries of the state. Although resource decisions are made by the individual states, the Federal Energy Regulatory Commission (FERC) is responsible for ensuring that wholesale purchases of electricity in the USA are just and reasonable and not unduly discriminatory. As a result of this statutory charge, FERC plays an important role in electricity markets and the integration of renewable energy into these markets.

The following case study focuses on the Independent System Operator of New England (ISO-NE), which is responsible for the electricity markets in the six state New England region of the USA, and also touches on a recent proposed rule by FERC that would establish specific requirements for variable generators. ISO-NE operates three forms of markets:

- **An energy market that includes both day-ahead and real time markets**. The day-ahead market produces financially binding obligations to deliver electricity at a single

[42] Database of State Incentives for Renewables and Efficiency. Available at: http://www.dsireusa.org/summarymaps/index.cfm?ee=1&RE=1 (RPS Policies).

clearing price; it is a financial forward market rather than a physical delivery market. The real time market is used to meet actual load and reflects the need on the system at any given hour. To the extent that the day-ahead market does not provide sufficient resources to meet requirements, the real time market provides additional resources that are paid through a single clearing price.

Renewable generators can bid into either market, but due to the inability to dispatch, the majority of variable generation units (such as solar and wind) do not bid into the day-ahead market and only bid into the real time market.

- **A forward capacity market** where generation resources, energy efficiency and demand response providers offer forward bids into the market to provide capacity. Renewable generation units can bid into the forward capacity market, but variable generation units are de-rated (compared to the nameplate capacity) because these units cannot commit to producing power when called upon. Additionally, the capacity rating of variable generation, for the purposes of the forward capacity market, takes into account the likely coincidence of the generator's output with peak load (for example, solar generation would receive a higher capacity rating than wind generation).
- **An ancillary services market**, which addresses reliability products such as voltage support and regulation services.

Currently, intermittent generation constitutes approximately 1.5% of the total resources available in ISO-NE, and these resources are not so much integrated into the markets as accommodated by the markets.

In recognition of the increased emphasis on renewable generation by policymakers, ISO-NE recently commissioned a report to examine the potential issues associated with increased penetration of wind resources in the New England grid. The New England Wind Integration Study was issued in December 2010, and identifies issues that arise when a greater number of variable resources, such as wind, are connected to the New England grid. However, the report does not attempt to resolve these issues.

In addition, FERC recently issued a notice of proposed rulemaking on Integration of Variable Energy Resources. It is intended to address issues associated with integrating variable generation into electricity markets. Specifically, FERC proposes to require:

- intra-hour transmission scheduling;
- variable generators to provide meteorological and operational data to transmission providers for the purpose of improved power production forecasting; and
- ancillary markets to provide generator regulation and frequency response services to address issues associated with balancing variable generation units.

The following case study will focus on existing market design and system operation arrangements in the New England area. The aspects of these arrangements covered in the case study broadly match the ones presented in the CEER case study above so that situations in the USA and Europe can be compared.

Gate closure time arrangements to accommodate renewable energy

The ISO-NE day-ahead market closes at 12:00 the day before the operating day. The real time market closes for dispatchable transactions at 12:00 the day before the operating day, and for self-scheduled transactions 60 minutes prior to the hour.

The FERC is proposing a rule that would require ISO-NE and other transmission operators to offer intra-hourly transmission scheduling. In proposing the rule, FERC notes that the scheduling protocols were developed at a time when the vast majority of generators could be easily scheduled. FERC has preliminarily concluded that hourly transmission scheduling protocols are no longer just and reasonable and may be unduly discriminatory. In particular, FERC states that the existing protocols "expose transmission customers to excessive or unduly discriminatory generator imbalance charges and are insufficient to provide system operators with the flexibility to manage their systems effectively and efficiently." FERC proposes to require protocols that allow scheduling at intervals of 15 minutes.

State cross border capacity allocation

Within the ISO-NE market, the location of the generator does not matter. For all practical purposes there is no distinction between states, and there are no cross border capacity allocation issues. Day-ahead markets in adjacent regional markets operate independent of each other: accordingly, the gate closure and clearing times differ from one market to another. There have not been any proposals to harmonise the gate closure times across the regions.

Balancing obligations on renewable energy generators and the role of the TSO in balancing

ISO-NE utilises a regulation market to address balancing issues; individual generators are not responsible for their own imbalances. However, the interconnection process typically requires that variable generators incorporate ramping procedures to minimise the potential impact on the electric system.

ISO-NE has a regulation market that consists of generators and other sources that can increase or decrease their output every four seconds to balance supply levels with the second-to-second variations in demand and to assist in maintaining frequency levels. The regulation clearing price is calculated in real time and is based on the regulation offer of the highest priced generator providing the service.

ISO-NE includes ten and 30 minute operating reserve requirements. ISO-NE operating procedures require that sufficient reserve capacity be available within ten minutes to meet the largest single system contingency and 25-50% of these reserves must be synchronised to the power system (spinning reserves). The amount of 30 minute reserve capacity is determined by the amount of capacity needed to meet half of the second largest contingency.

ISO-NE has not yet altered the reserves due to increased renewable resources. However, the recent Wind Integration Study concluded that the need for additional reserves varies as a function of wind generation. Therefore, it would be advantageous to have a process for scheduling reserves day-ahead or several hours ahead, based on forecasted hourly wind generation. It may be inefficient to schedule additional reserves using the existing "schedule" approach, by hour of day and season of year, since that may result in carrying excessive reserves for most hours of the year. The process for developing and implementing a day-ahead reserves scheduling process may involve considerable effort.

Systems to forecast non programmable renewable energy generation

The ISO-NE forecast system is currently intended to forecast necessary load, and is not designed to address expected production from variable generators. The New England Wind Integration Study concluded that with higher levels of wind penetration more accurate intra-day and day-ahead wind power forecasts will be required. In addition it noted that additional tools to forecast wind ramping would also be necessary to ensure SOs can prepare for volatile wind situations.

The Wind Integration Study recommends that ISO-NE forecast wind availability on a day-ahead basis to ensure that conventional generation is not overcommitted and the reserve margin is not larger than necessary. The study further recommends that intra-day forecasting be performed to reduce dispatch inefficiencies. Finally, the study suggests that ISO-NE publish the day-ahead wind forecast alongside the day-ahead load forecast to contribute to overall market efficiency.

The FERC proposed rule would require intermittent renewable generators to provide site-specific meteorological data that includes the following information as a minimum: temperature, wind speed, wind direction and atmospheric pressure for wind generation; and temperature, atmospheric pressure and cloud cover for solar generation. The generators would be responsible for providing the forecasting data to the regional transmission organisation, although the frequency with which the data must be sent has not yet been determined.

The implications of priority dispatch of renewable energy resources

Rather than prioritise dispatch of renewable energy resources, ISO-NE dispatches resources based on economic efficiency, with the lowest-priced resource dispatched first. However, ISO-NE allows variable generators to 'self-schedule'; i.e., the unit does not need to bid into the market but simply provides power into the market whenever it operates and receives the clearing price that is available for that time period.

Provision of network/system services by renewable energy installations in order to react to both changing meteorological and grid conditions

Currently, there is no requirement for variable generators to provide grid services in the electricity market. However, the interconnection requirements for variable generators typically require control measures related to ramping output. The FERC proposal on ancillary services would require that all generators either:

- take service under a Generator Regulation and Frequency Response Service tariff; or
- demonstrate that they have satisfied their regulation service obligation through dynamically scheduling their generation to another balancing authority area; or
- by self-supplying regulation reserve capacity from generation or non-generation resources.

Technical requirements of TSOs for connecting and managing renewable energy generation

Although variable generation units typically require different protection schemes than dispatchable units, ISO-NE does not have different requirements for studying the interconnection of renewable units, and does not give preferential treatment to renewable generation units with respect to the timing of interconnection review.

There is no proposal at the moment to impose additional requirements on renewable units, other than the proposal to require variable renewable units to provide meteorological data to the regional transmission organisation.

3. The impact of renewable energy generation on conventional generation

There are a number of fundamental differences between renewable and traditional generation that affect how these resources interact in an integrated system. As national energy strategies and international compacts increasingly encourage investment in renewable generation, the interaction between these types of generation will inherently change the way system operators plan for and manage electricity grids. In this chapter we will take a closer look at the interplay between conventional and renewable energy generation to explore the emerging challenges and solutions arising from relatively large scale integration of renewable energy into a given interconnected electric power system.

3.1 System planning

One of the biggest differences between traditional energy technologies and some renewable energy generation is the intermittency of the resource. As explained in Chapters 1 and 2 the variable and seasonal nature of more abundant RES creates new challenges to system operators in ensuring stability of the grid.

Renewable energy, such as solar, wind, biomass, riverine and wave generation, is highly dependent on weather and tied to natural cycles, such as seasons or droughts. The variability of renewable resources continues to present a challenge for system planning. These challenges include: reliability meeting demand, implementing national and international initiatives to adhere to renewable energy quotas, preserving an economically sustainable and/or market-based electricity sector, and maintaining the stability and security of the electricity system.

For example, in many cases natural gas units are the resources that are most likely to be displaced by intermittent generation sources such as wind. The majority of such units can be dispatched quickly, with minimal start-up requirements, and are necessary for adequate system operation during times when wind is not available. However, as the number of hours that natural gas units operate declines, it is likely that there will need to be some method of ensuring that the units are provided adequate compensation so that they can be available when needed.

3.2 Ancillary services

Conventional generation technologies such as coal-fired, large hydropower and nuclear facilities provide large scale, generally stable generation able to supply baseload electricity demand. These baseload resources are complemented by scalable and dispatchable technologies such as natural gas turbines that are able to provide services during peak demand and in urban load pockets. They can be automatically ramped up or down to provide instantaneous response to ancillary services including frequency regulation, reactive power and voltage control for the overall stability of the power system.

SOs depend on the predictability and dispatchability of conventional resources to schedule adequate primary and secondary frequency control reserves. Due to their variable nature, generation facilities reliant on solar and wind cannot meet the demands for ancillary services of the overall system.

Thus conventional generators must operate with increased capacity margins to enable the integration of variable renewable generation. In addition, a 2011 study by Lawrence Berkeley National Laboratory concludes that in the USA a combination of several factors has led to declining quality of frequency control in conventional energy.[43] These factors include increased operation of generation facilities at peak efficiency.

This is further compounded by the fact that while secondary frequency balancing services are compensated via existing policies, crucial instantaneous reserve capability provided by conventional generation facilities, such as coal, is currently not. While renewables do not necessarily play a role in this trend, increasing integration of renewable energy may exacerbate the problem and/or increase the vulnerability of the grid to frequency disruptions. Current policies/regulations in many countries may not account for emerging challenges presented by the interaction between conventional generation, evolving in and of itself, and the increasing integration of renewable energy. Therefore, many countries are taking steps to adapt their policies and regulation framework.

In considering the changing face of the electricity sector, policy makers and regulators must also take in to account the rapidly developing technology landscape in the search for solutions. Frequency regulation challenges posed by the variability and lack of dispatchability of some renewable generation can potentially be addressed by energy storage options, both at the generation and distribution levels. The Independent System Operator of New England (ISO-NE), discussed in Chapter 2, has initiated a pilot program under which storage can participate in the regulation market provided that the storage unit can respond within four seconds to automatic generation control and is sized between one and five MWs. Advanced metering technologies and ‘smart’ transmission systems are also potential tools for managing electricity supply and demand.

The below case studies from CEER and NARUC exemplify the policy challenges of balancing: economic, environmental, legal and political interests, in planning for and viably operating an electricity system with increasing amounts of renewable energy. The examples provided approach the issue of the impact of renewable energy on conventional generation from both a policy and technical standpoint and provide insight on how electricity policies need to adapt to meet new challenges presented by renewable energy integration.

[43] Lawrence Berkeley National Laboratory. “Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation. 2011.
www.ferc.gov/industries/electric/.../frequencyresponsemetrics-report.pdf

3.3 Case study 6: How to provide back-up generation capacity in Europe

TSOs and utilities are required to keep some of their available generation resources in standby mode or to operate in such a way as to allow them to respond to grid emergencies and changes in grid frequency in an appropriate manner.

In a context where wind and, in general, non-programmable energy sources represent a larger share in the electricity generation mix, there may be a significant impact on existing conventional capacity in terms, for example, of lower operating hours or increased start-up costs. As wind and solar powered electricity increases supply variability, some countries are looking at the need for flexible supplies with capacity markets or capacity payments to ensure enough capacity is available.

In 2009, the **Italian** regulator presented a proposal to introduce a generation capacity market which is planned to enter into operation in 2012. This was in anticipation of the expected increase in wind (and other non-programmable) power capacity and the need to maintain security of supply and generation adequacy standards.

The proposal will require the TSO to define a long term capacity target, which includes the expected demand of electricity and an adequate reserve margin. The target will be based on the Value of Lost Load (VOLL) and the Loss of Load Expectation (LOLE).

The TSO should then organise a capacity market through auctioning procedures whose costs should be allocated to withdrawing market operators, depending on their contribution to the peak load.

Generators will be incentivised to enter long term agreements with the TSO for providing their capacity under an option contract. They will receive a premium paid by the TSO and in exchange will have to pay the TSO the difference between the market price and the strike price of the standard contract. The strike price will be defined with reference to the variable cost of a peak plant, while the premium will result from the auctioning process.

In **France**, recent studies on peak load management underlined several market design failures. Peak load generators seem to be facing difficulties covering their fixed costs, and the energy-only model may be unable to deliver the correct price signals to stimulate the necessary generation investments. This is reflected by the €3000 per MWh market price cap being reached only once in ten years for a four period.

In 2010, France passed a law to reform the organisation of electricity markets and tariffs. As the need for additional capacities is increasingly important as we approach the 2015 horizon (3 GW), the French energy ministry is calling for the development of a capacity obligation mechanism to ensure generation adequacy. It will require an obligation on suppliers to have capacity contracts/certificates with respect to the projected peak load demand of their portfolio, and should probably include a forward term. Special attention should be paid to the development of a level playing field for demand response.

Defining French future market design is an ongoing process. Implementation decrees are likely to have restructured the market design by 2012.

In **Spain**, there is a growing objection by conventional technology to the increasing renewable energy penetration, especially from coal and CCGT power plants. This is because renewable energy goes before them in the merit order, adding to the current demand decrease and the overinvestment in CCGT technology. These plants can't operate a sufficient number of hours to recover their investment costs.

At the same time there is an increasing need for back-up generation capacity to balance intermittent renewable generation. Spain has introduced capacity payments mechanisms, which require compliance with specific availability requirements that make the capital costs of new investments in conventional energy generation viable.

Conventional generation with installed capacity over 50 MW are eligible to receive capacity payments if their annual average available capacity is equal (or above) 90% of the net installed generation capacity during the periods of peak demand. New and existing generators are eligible during the first ten years after installation. Specifically:

- Generators installed before 2007 receive €20.00 per MW per year for ten years since installation.
- Generators installed after 2007 receive a capacity payment per for ten years. This is computed as follows:
    - If the coverage index[44] is lower than 1.1 the capacity payment amounts to €28.00 per MW per year.
- If the coverage index is equal or higher than 1.1 the capacity payment is lower than in the previous case, and amounts to: [193.000 - (150.000 x coverage index)] € per MW per year.

Spain is also looking at opportunities to develop additional back-up generation capacity through electricity storage. Although no special incentives to develop electricity storages exist so far, 'ad hoc' incentives for specific projects are available. This is the case, for instance, for mixed wind and pumping generation, where the regulator proposes to the government a tailor-made incentive for the generator.

In **Germany**, the unlimited feed-in tariffs payments for renewable generation oblige conventional generation units to be more flexible in order to remain economically viable.

The impact of a large penetration of wind generation on conventional capacity has not been fully investigated in the German context. However, some useful considerations have been developed concerning the participation in the control energy market. The renewable energy installations would be in competition with conventional capacities. The implication being that some conventional capacities would no longer be economically feasible if the price for control energy falls as a result of the rising number of participants in the control energy market. But so far in Germany only renewable energy installations for which the feed-in tariff

[44] Coverage index is the generation capacity available in the system / maximum demand in the system.

is not claimed (but could be claimed) can participate in the control energy market. With respect to wind generators, it is not clear whether they are reliable enough to offer positive secondary and tertiary control. Renewable energy installations which receive a feed-in tariff are not allowed to participate at the control energy market.

In Germany there are no direct incentives to develop electricity storages. However pump storage stations and other storage facilities are exempted from paying network charges for the electricity drawn from the network for ten to 20 years. The requirements for the exemptions were expanded in 2011.

In **Great Britain**, the Department of Energy and Climate Change has launched a consultation to deliver fundamental reforms to the electricity market to ensure the UK has secure, affordable, low carbon supplies of electricity over the long term. These reforms are still ongoing. Among these reforms, the Government foresees the introduction of capacity payments to ensure back-up capacity is available at peak times. In particular, targeted payments are meant to encourage security of supply through the construction of flexible reserve plants or demand reduction measures. The intention of the proposed mechanisms is to ensure there remains an adequate safety cushion of capacity as the amount of intermittent and inflexible low-carbon generation increases.

3.4 Case study 7: Wind integration in the Bonneville Power Administration balancing area

The Bonneville Power Authority (BPA) is facing new challenges in its responsibilities to match electricity supply with demand within its balancing area. The combination of high wind output and high water levels during the spring season within the Federal Columbia River Power System (FCRPS) can create, and indeed have created, temporary oversupply of electricity. In the absence of commensurate demand (or transmission capacity to move supplies to load centres), this oversupply compels BPA to choose from a list of second best options to reduce electricity production. These options are the centre of a large and growing controversy among energy players in the Northwest.

Hydroelectricity provides more than 60% of Washington’s electricity and more than 40% in Oregon.[45] Most of the hydroelectricity in the Pacific Northwest region is generated in the FCRPS and marketed by the BPA, which sells electricity to Washington, Oregon, Idaho and Western Montana. It provides about 35% of the region’s electricity.[46]

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[45] *See* Washington Department of Commerce, “2009 Washington State Electric Utility Fuel Mix.” www.commerce.wa.gov/site/539/default.aspx (accessed June 3, 2011); *and* Pacific Northwest Utilities Conference Committee, “Oregon Fuel Mix 2005 for Electric Utilities.” http://www.pnucc.org/documents/OregonFuelMix.pdf (accessed June 3, 2011).

[46] Bonneville Power Authority, “Federal Columbia River Power System,” http://www.bpa.gov/power/pg/fcrps_brochure_17x11.pdf (accessed April 19, 2011).

BPA also controls approximately 75% of the high voltage transmission capacity in the region (called the Federal Columbia River Transmission System or FCRTS), which serves approximately 385 transmission customers.[47]

BPA is subject to FERC requirements to allow independent electricity generators open access to the transmission system.[48] Other state and federal policies also bear directly upon BPA's operations. For example, the Clean Water Act and the Endangered Species Act, as well as state water quality laws, obligate BPA to maintain within the Columbia River system water conditions that allow threatened or endangered fish species to survive and reproduce.[49]

State water quality laws differ; in the case of over-generation from dams, the difference of concern is that of the total maximum daily load of total dissolved gas (TDG).

In a spill event, elevated levels of TDG occur immediately downstream of dams when water plunges downward through a dam's spillway instead of through its turbines. The resulting gas super saturation causes gas bubble trauma in fish and, at high levels or for extended periods of time, is fatal.[50] The nationwide water quality standard adopted by the US Environmental Protection Agency for maximum TDG is 110% relative to ambient barometric pressure.[51] However, Oregon and Washington have issued exemptions to this standard to increase the amount of spill over dams to aid juvenile fish migrating to the ocean. The Washington Department of Ecology limits TDG in these circumstances to 115% at dams' forebays,[52] while Oregon law will allow up to 120% under certain conditions.[53]

In addition, state renewable portfolio standards such as those enacted by Oregon, California and Washington are driving changes in the resource mix that relies on the transmission

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[47] Bonneville Power Authority, "BPA Fast Facts" at 1 (2009).

[48] Federal Energy Regulatory Commission Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," (1996).

[49] See US Fish & Wildlife Service, Species Reports, Listing and Occurrences for Washington. Environmental Conservation Online System, http://ecos.fws.gov/tess_public/pub/stateListingAndOccurrenceIndividual.jsp?state=WA&s8fid=112761032792&s8fid=112762573902 (accessed April 27, 2011).

[50] Pacific Northwest National Laboratory, "Total Dissolved Gas Effects on Incubating Chum Salmon Below Bonneville Dam," at O-1 (January 2009).

[51] Washington Department of Ecology, "Standard Operating Procedure for Monitoring Total Dissolved Gas in Freshwater," Version 1.0 (2007), http://www.ecy.wa.gov/programs/eap/qa/docs/ECY_EAP_SOP_002MonitoringTotalDissolvedGas.pdf (accessed May 12, 2011).

[52] Washington Department of Ecology. "Total Dissolved Gas on the Columbia and Snake Rivers,"

http://www.ecy.wa.gov/programs/wq/tmdl/ColumbiaRvr/ColumbiaTDG.html (accessed May 13, 2011).

[53] Oregon Department of Environmental Quality, "TDG Overview," http://www.nwd-wc.usace.army.mil/tmt/wqnew/tgg/2011_meeting/ODEQ_TDG_overview.pdf (accessed May 13, 2011).

system operated by BPA. These standards have resulted in enormous growth in electricity production from wind in the region. Several states in the Pacific Northwest region have established renewable standards that heavily influence the mix of new generating resources within the FCRTS. Oregon requires large utilities to produce 25% of their electric load from renewable resources by 2025.[54] In Washington, large utilities must produce 15% of their electric load from non-hydro renewable resources by 2020.[55]

California requires its three major utilities to produce 33% of their total electric load from renewables by 2020.[56] All of these renewables requirements allow utilities to use renewable energy credits to meet all or a portion of the total renewable resource target for a particular deadline.

According to the Western Renewable Energy Generation Information System (WREGIS), the organisation responsible for tracking and verifying renewable energy production in the Western Electricity Coordinating Council coverage area, more megawatt hours of new renewable generating capacity came from wind than from any other resource in 2010.[57] In Washington, the areas with the highest wind generating potential are located within the Columbia River watershed.[58] Most of the windiest areas in the northern part of Oregon also fall within the watershed.[59] Because state renewable requirements will continue to drive utility acquisitions of wind resources, the problem of balancing variable wind output with high water conditions during the spring will likely become increasingly challenging.

BPA management of the June 2010 high water event

In the spring of 2010, a dry winter heralded low spring river flows throughout the Columbia River system. According to BPA, its ecological management of the FCRPS at that time focused on ensuring river flows and spill were high enough to allow juvenile salmon to migrate safely to the Pacific Ocean.[60] However, in early June 2010, storms caused

[54] ORS 469A. See http://www.oregon.gov/ENERGY/RENEW/RPS_Summary.shtml (accessed April 29, 2011).

[55] Revised Code of Washington 19.285.040.

[56] CA Executive Order S-21-09 at 2 (2009).

[57] Western Renewable Energy Generation Information System, "WREGIS Annual Report 2010," http://www.wregis.org/uploads/files/816/WREGIS%202010%20Annual%20Report.pdf (accessed April 29, 2011).

[58] See the National Renewable Energy Laboratory, "Washington – Annual Average Wind Speed at 80 m," (map) http://www.windpoweringamerica.gov/images/windmaps/wa_80m.jpg and the Washington Department of Ecology "Columbia River Basin," (map), http://www.ecy.wa.gov/programs/wr/cri/Images/crb-shd.pdf (accessed April 29, 2011).

[59] See the National Renewable Energy Laboratory, "Oregon – Annual Average Wind Speed at 80 m," (map) http://www.windpoweringamerica.gov/images/windmaps/or_80m.jpg and the Washington Department of Ecology "Columbia River Basin," (map), http://www.ecy.wa.gov/programs/wr/cri/Images/crb-shd.pdf (accessed April 29, 2011).

[60] Bonneville Power Administration. "Columbia River High-Water Operations, June 1-14, 2010," at 2 (September 2010).

unseasonably heavy precipitation and the resulting runoff, combined with high winds generating ever more electricity from wind farm development proliferating in the region, resulted in a temporary electricity oversupply which grew close to surpassing loads and causing system instability.

In response, BPA shifted the focus of its ecological management toward reducing spill to keep TDG levels low enough to comply with Washington law.[61] BPA developed a series of strategies and operational modifications to maintain system reliability while preventing unlawful TDG levels across the FCRPS infrastructure.

Historically, BPA has sold surplus power at very low rates to operators of thermal generating plants (coal, oil, natural gas etc.) in the Northwest and California.

During the high wind/high water event in June 2010, BPA also took additional steps to minimise TDG levels while providing other system services. These steps included:

- cancelling non-essential hydroelectric generating unit outages;
- seeking extra water storage in a large reservoir on the lower Columbia River;
- shaping generation from several dams into the times of heaviest electric load; and
- reducing the amount of water held behind dams for use in balancing wind power entering the system.[62]

While BPA managed the FCRPS such that no statutory obligations were violated, it did not sell all the power available in the system at that time, spilling about 1000 MW in the month of June and approaching 120% TDG super-saturation on parts of the system.[63]

BPA administrator's record of decision

Above average water years on the Columbia are relatively rare. The most recent year before 2010 was 1999, at a time when generation from wind in the region occurred at very low levels relative to today.[64]

After the events in June 2010 and in anticipation of recurring high wind/high water events in future years, BPA released Administrator's Draft Record of Decision on Environmental Redispatch and Negative Pricing Policy, (Draft ROD) in February 2011. In the document the agency outlined its proposal for managing the FCRPS in specific circumstances of high

[61] Bonneville Power Administration. "Columbia River High-Water Operations, June 1-14, 2010," at 2 (September 2010).

[62] Bonneville Power Administration. "Columbia River High-Water Operations, June 1-14, 2010," at 6 (September 2010).

[63] Bonneville Power Administration. "Administrator's Draft Record of Decision on Environmental Redispatch and Negative Pricing Policy," at 15 (February 18, 2011).

[64] Bonneville Power Administration. "Columbia River High-Water Operations, June 1-14, 2010," at 12 (September 2010).

water. It proposed that BPA would not pay negative prices to encourage generators to replace production with federal hydropower.[65]

Many of the mitigating steps taken by BPA during the 2010 event were included in the Draft ROD. BPA also referenced the option to reduce balancing reserves through the adoption of intra-hour scheduling.

The Draft ROD stated that thermal generators usually find it economical to displace their generation with low or no cost hydropower. Conversely, wind power projects have the economic incentive to operate as much as possible in order to qualify for Production Tax Credits (PTCs) and Renewable Energy Credits.

BPA's Draft ROD redispatch protocol would replace thermal generation with hydropower, and then redispatch or completely displace generation from variable resources that do not receive Production Tax Credits, and finally redispatch or displace generation from variable resources that are eligible for Production Tax Credits.[66]

Stakeholder responses to draft record of decision on environmental redispatch and negative pricing policy

Investor owned electric utilities in the region submitted extensive comments on BPA's Draft ROD on the environmental redispatch protocol.[67] Generally these comments opposed the Draft ROD, citing concerns that the proposed redispatch would unfairly curtail non Federal generators in favour of Federal ones, and that the negative pricing policy would ignore true market conditions, in which revenues received by renewable generators through renewable tax credits and renewable energy credits sales allow renewable generators to operate profitably even under negative pricing conditions.[68]

It was argued that the negative pricing policy would, in fact, be very costly for wind generators because it would prevent them from receiving state and federal production tax credits and from selling renewable energy credits that they would have generated in the absence of curtailment.[69]

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[65] Bonneville Power Administration. "Administrator's Draft Record of Decision on Environmental Redispatch and Negative Pricing Policy (February 18, 2011). http://www.bpa.gov/corporate/AgencyTopics/ColumbiaRiverHighWaterMgmnt/Draft%20ROD%20ERNP.pdf (accessed April 26, 2011).

[66] Bonneville Power Administration. "Administrator's Draft Record of Decision on Environmental Redispatch and Negative Pricing Policy," at 22 (February 18, 2011).

[67] Puget Sound Energy, PacifiCorp, Avista, and Portland General Electric Company submitted comments on the BPA Environmental Redispatch and Negative Pricing Policy. http://www.bpa.gov/applications/publiccomments/CommentList.aspx?ID=121 (accessed April 28, 2011).

[68] See comments of PacifiCorp at 3 and 4 (March 11, 2011).

[69] See comments of PacifiCorp at 1 (March 11, 2011) and comments of Puget Sound Energy (ERP110033) at 5 (March 11, 2011).

Finally, the possibility was raised that a BPA curtailment of wind generation during environmental redispatch events might further impact utilities economically by impeding utility compliance with the renewable energy standards.[70]

Noncompliance carries penalties for utilities in Oregon, Washington, and California, commensurate with the shortfall from the target.[71]

Consumer owned utilities tended to support the Draft ROD. For example, the Cowlitz County Public Utility District (Cowlitz) strongly supported the Draft ROD. Cowlitz stated that BPA's proposal to first redispatch thermal generators that do not have reliability requirements, then variable energy resources (VERs) that do not receive Production Tax Creditss, and finally, all remaining VERs, is the "most economically rational" approach. Cowlitz commented that if BPA were to curtail all generators on a pro-rata basis "unnecessary economic damage will be incurred," because least-cost generation would be curtailed at the same levels as more expensive generation.[72] Snohomish Public Utility District (Snohomish) stated that it supported the ROD conceptually, but it requested that BPA "redispatch all VERs proportionately, irrespective of a project's eligibility for Production Tax Credits."[73] Snohomish has three contracts for wind generation for which it also receives the associated renewable energy credits. Production Tax Credits earned from the projects belong to the wind developers with whom Snohomish has contracted, and Snohomish commented that it would be heavily impacted by BPA's proposal to redispatch VERs that do not receive production tax credits.[74]

Advocates for renewable energy and fish protection both generally opposed BPA's Draft ROD. A coalition of fish protection advocates, Save Our Wild Salmon, argued that the approach described in the Draft ROD would create an unnecessary adversarial relationship between wind development and environmental protection in the region.[75] Comments submitted by the Renewable Northwest Project (RNP) on behalf of over fifty member organisations (some of which submitted additional comments separately) echoed this comment.

[70] See comments of Puget Sound Energy at note 64.

[71] See California Public Utilities Commission. "Compliance, Penalties, and Flexibility." *www.cpuc.ca.gov*. 25 Nov. 2009. Web. 29 Apr. 2011. http://www.cpuc.ca.gov/PUC/energy/Renewables/FAQs/02ComplianceAndFlexibility.html; Oregon Public Utilities Commission, "Oregon RPS and Related Policy and Legislative Package Outline," at 1 (October 5, 2006); and Washington Utilities and Transportation Commission, "Renewable Energy and Conservation Initiative," http://www.utc.wa.gov/regulatedIndustries/utilities/energy/Pages/renewableEnergyAndConservationInitiative.aspx (accessed April 29, 2011).

[72] Comments of Cowlitz County Public Utility District at 1 (March 11, 2011).

[73] Comments of Snohomish Public Utility District at 2 (March 11, 2011).

[74] Comments of Snohomish Public Utility District at 2 (March 11, 2011).

[75] Comments of Save Our Wild Salmon at 1 (March 11, 2011).

They rejected BPA's characterization of its proposed redispatch plan as 'environmental'. RNP, along with other commenters, argued that the additional spill allowable under Oregon's TDG standard would eliminate "between 16% and 100% of the [environmental redispatch] situations" and that TDG levels in excess of Washington's 115% standard are not actually harmful to fish during discreet over-generation events.[76]

Independent wind power developers strongly opposed the Draft ROD. Iberdrola Renewables Inc. (Iberdrola) submitted extensive comments in which it stated that BPA "proposes to unilaterally curtail wind generation, take firm transmission service from wind generators, and use that transmission to serve such generators' customers with Bonneville's hydropower instead." Iberdrola characterised the Draft ROD as "a bold attempt to shift Federal system costs to wind generators in a manner that violates Bonneville's statutory mandates, unduly discriminates against wind generators, breaches transmission and power contracts, and is rife with regulatory and operational problems."[77] Iberdrola then argued that the Draft ROD is inconsistent with a wide swath of federal laws and requirements, along with the FERC prohibition of market manipulation, BPA's own Large Generator Interconnection Agreement, Small Generator Interconnection Agreement, Open Access Transmission Tariff and the terms and conditions of BPA's existing power purchase agreements.[78]

Conclusion: BPA's next steps

BPA released the Administrator's Final Record of Decision "BPA's Interim Environmental Redispatch and Negative Pricing Policies" (Interim ROD) on 13 May 2011, after several months of discussion with stakeholders.[79] The Interim ROD built on the framework set out in the Draft ROD on the Environmental Redispatch protocol. Notably around the idea that BPA would first replace thermal generation with federal hydropower, then redispatch variable energy resources not receiving Production Tax Credits, and finally redispatch all other VERs.[80]

In the Interim ROD, BPA issued extensive responses to opposing arguments presented by wind power producers and other parties in comments on the Draft ROD. For instance, regarding interconnection agreements, BPA stated that all generators interconnected to the

[76] Comments of Renewable Northwest Project at 2 (March 11, 2011).

[77] Comments of Iberdrola Renewables, Inc. at 2 (March 11, 2011).

[78] Iberdrola cited the following specifically: the Pacific Northwest Consumer Power Preference Act; the Pacific Northwest Electric Power Planning and Conservation Act; and the Federal Columbia River Transmission System Act. See comments of Iberdrola Renewables, Inc. at 5-24 (March 11, 2011).

[79] See Bonneville Power Administration, "BPA's Interim Environmental Redispatch and Negative Pricing Policies," (May 2011). See also Bonneville Power Administration, "Transmission Services Business Practice: Environmental Redispatch, Version 1," April 11, 2011. Bonneville Power Administration.

[80] "Administrator's Final Record of Decision on Interim Environmental Redispatch and Negative Pricing Policy," at 16 (May 13, 2011).

FCRTS or within BPA's Balancing Authority Area have the obligation to reduce generation when ordered to do so by BPA.

All generators with an interconnection agreement with BPA, such as Large Generator Interconnection Agreements, Small Generator Interconnection Agreements, Balancing Authority Service Agreements, and other generation interconnection agreements, must follow BPA's Dispatch Orders. These interconnection agreements specifically provide that generators are required to follow all Dispatch Orders issued by BPA, such as an order to reduce generation during an Environmental Redispatch.[81]

Regarding its Open Access Transmission Tariff, BPA stated that Environmental Redispatch does not affect transmission customers' transmission rights because BPA will still make all the agreed-upon energy deliveries. BPA stated that it will continue to explore amendments to the tariff to "specifically delineate the effect of BPA's environmental and related statutory obligations (...) to be absolutely clear regarding the terms and conditions of transmission service"[82] even though BPA also states that it will not be 'curtailing' a transmission schedule per se because it will substitute federal hydropower to "ensure that all transmission schedules are met."[83]

Of the many issues and concerns raised about BPA's ROD on Environmental Redispatch, none argued that BPA does not face complex competing interests in its operations. Unsurprisingly, comments reflected the financial and political positions of each stakeholder. BPA implemented the environmental redispatch protocol on 18 May 2011, and the Interim ROD will be in effect through 30 March 2012.[84] In the meantime, questions about the legality of BPA's ROD have been raised.

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[81] "Administrator's Final Record of Decision on Interim Environmental Redispatch and Negative Pricing Policy," at 16 (May 13, 2011).

[82] "Administrator's Final Record of Decision on Interim Environmental Redispatch and Negative Pricing Policy," at 18 (May 13, 2011).

[83] "Administrator's Final Record of Decision on Interim Environmental Redispatch and Negative Pricing Policy," at 43 (May 13, 2011).

[84] Bonneville Power Administration, www.bpa.gov, "Oversupply," http://www.bpa.gov/corporate/AgencyTopics/ColumbiaRiverHighWaterMgmnt/ (accessed June 3, 2011).

4. Legal, financial and socio-economic implications of undertaking renewable energy projects on an international scale

4.1 Introduction

This chapter addresses renewable energy projects that are developed on an international scale. It provides broad overview of theoretical issues pertaining to such projects and then continues with a detailed case study on the Mediterranean Solar plan that was developed by MEDREG.

To begin with, renewable energy projects undertaken on an international scale have distinct aspects involved with their promotion. For instance, as they have a supranational coverage, successful completion of such projects requires significant coordination between the governments and investors involved.

Indeed, large international scale projects can bring significant benefits to all involved parties. To illustrate, international projects can promote integration of renewable energy to a much greater extent than domestic projects. Interconnectedness and market synchronisation between project countries can help to mitigate the problems of intermittency associated with renewable generation and enable higher levels of renewable penetration. Commercially, the increased levels of market interconnectedness that international projects demand can also provide generators (both renewable and conventional) with more opportunities to trade, and therefore benefit consumers through increased levels of competition.

On the other hand, large scale international projects sometimes face greater challenges than domestic projects. As not one, but a number of countries are involved, such projects require strong unity and coordination between countries in order to attract investors.

4.2 Some barriers for supranational scale projects

There are several possible barriers to developing supranational-scale projects, including:

1) Insufficient information and expertise in renewable technologies.

Renewable development demands complex technology. Potentially, many countries do not have enough skilled personnel who can install, operate and maintain renewable energy technologies as developers often lack sufficient technical, financial and business skills.

2) Low investment levels for renewable projects

The ability to develop and commission renewable generation projects is highly contingent upon each country's economic evolution and political situation. The economic crises suffered by some countries over the past few years have impacted the development of appropriate renewable energy policies or even the improvement of existing policy designed to address conventional energy technologies.

This social and political situation, as well as the lack of economic security, creates uncertainty for possible investors over return on projects with high upfront costs. Renewable energy systems require more investment cost per kW than conventional energy sources. Development of renewable generation plants requires higher amounts of financing for the same capacity installation, and therefore the cost of capital is a more significant issue for renewable energy investments than it is for conventional energy projects. In some countries poorly developed financial markets, products and institutions, as well as high credit and economic risks, are strong barriers to renewable projects.

3) Insufficient network capacity

Some renewable technologies are intermittent and need back-up energy; wind energy for example cannot cover demand peaks or respond to an increase in demand without being accompanied by other sources of electricity. This makes systems with high levels of renewable penetration more difficult to manage for the TSO.

In some countries, network capacity is insufficient to manage new generation connecting to a grid, which therefore creates an extra barrier to new projects.

4) Legislative and regulatory framework undeveloped or without stability

Developing countries have implemented legislation to try and incentivise, and support the exploitation of natural resources as sources of primary energy. Nevertheless, in most cases this legislation does not tend to be stable, which in practice means that the progress of projects is slow and difficult. Unclear guidelines for authorisation procedures, subjective (rather than objective) and opaque procedures for grid connection, and long authorisation periods to obtain permission for grid connection are examples of some barriers to developing renewable projects.

5) Lack of experience in promotion mechanisms

Many countries have no previous experience in renewable energy promotion policies. This might be an additional difficulty at the early stages of project implementation.

4.3 Some mechanisms to promote international scale projects

There are, however, mechanisms to remove or at least mitigate these barriers and to promote renewable projects on an international scale, such as:

1) Guarantee of regulatory stability

The stability of regulation is a basic starting point to promoting renewable projects. National and foreign private investors will be interested in investing in new facilities if there is low regulatory risk. The experience in many industrialised countries shows that stability in regulation of electricity generation is a very important aspect for new investments.

Furthermore, reducing the risk is a key phase in reducing the premium demanded for capital markets. Regulation has to offer sufficient guarantees to ensure that economic incentives are stable and predictable during the entire life of a facility.

2) Defining specific national targets/objectives

Defining national renewable energy targets in national legislation is a key point for each project member. Targets have to be ambitious but realistic, and they must be in accordance with the economic, social and physical features of the country and the possible evolution of the energy prices. The high and volatile price of oil seen in recent years should encourage governments to consider other ways of generating electricity that reduce foreign dependence. It is also important to define the targets, taking into account other national priorities as tourism, industry development, employment etc.

Increasing cross border levels of interconnection and the promotion of international electricity markets will help to achieve the targets.

3) Development of network development plans

To achieve a desired level of renewable energy development, and to combine these targets with the guarantee of supply, it is necessary to build an adequate electricity network infrastructure. A minimum level of network development should be defined through mandatory planning. The development of RES will increase the need for stronger grids and interconnectors.

In the development plans it is necessary to take into account that the network has to connect customers to the location of renewable resources.

4) Accessing and integrating renewable energy

It is important to develop interconnection procedures for renewable facilities. Non-discriminatory access rules and priority of dispatch should also be established.

Members should ensure that network operators in their territory guarantee the transmission and distribution of electricity produced from renewable projects. They should also provide for non-discriminatory connection to the grid system by RES. TSOs should give dispatch priority with market based balance responsibility to generating installations using RES, although compliance with a security of supply guarantee is also necessary to ensure that load requirements are met.

5) Collaboration programs between members

Developing mechanisms to foster collaboration regarding the promotion of renewable energy could be a way to remove certain barriers. Collaboration between different countries is a key means of promoting efficient industries and solving research and development issues.

6) Definition of promotion mechanisms

Transparent and stable national legislation is important in any mechanisms used to promote renewable energy. In addition, the mechanisms should be open and flexible so as to adapt to the economy's evolution, but there should be sufficient stability to support investments in renewable energy resources.

It is also important that support schemes are introduced as a mechanism for promoting renewable energy policy; such schemes could take the form of investment support and operating support. In order to provide the necessary support, it is important that there is sufficient economic information regarding the technologies that are being supported. This information would include investment costs, average operating costs and income taken from real facilities started up during the preceding period.

7) External financing

Finally, developing countries must have external financing to increase their renewable capacity. There are a number of sources of external financing, and it is necessary to optimise all possibilities to advance in the renewable deployment.

4.4 Case study 8: The Mediterranean Solar Plan

Introduction

The Mediterranean Solar Plan (MSP) is one of the key projects proposed in the Union for the Mediterranean (UfM).

- The prime objective is the development of a sustainable energy future in the Mediterranean region: more precisely, to install 20 GW of RES (RES) in southern Mediterranean countries by 2020.
- Other targets include the promotion of energy efficiency in the Mediterranean countries and the implementation and reinforcement of necessary interconnection infrastructure to support renewable resources.

All partners cooperating within the MSP shall support all initiatives aimed at creating favourable framework conditions, with a particular focus on the following aspects:

1) Regulatory framework

The MSP will pay specific attention to the creation of a regulatory framework that avoids uncertainty and is favourable to investments in the renewable energy sector.

2) Know-how and technology transfer

The MSP will foster and encourage the development of national capacity and transferring of the technology to the developing countries.

3) Electricity transmission

The MSP will contribute to identifying and promoting electrical interconnections. These interconnections are absolutely vital to enable power plants to export part of their production to other countries. Special attention will be given to the improvement of north-south interconnections in order to make possible the export of green electricity from Mediterranean countries to EU countries.

4) Political support

The governments of all Mediterranean countries should be involved and offer political support and facilitate the cooperation and coordination between countries.

Cross border capacity allocation

One of the measures of the success of the MSP targets is the active reinforcement of the existing interconnections along with the planning of new ones. The objectives for new renewable generation are very demanding and the constraints on the interconnections will be one of the problems to face. These constraints should be solved by means of reciprocal, market coupling based mechanisms such as:

- **Explicit auctions:** different time basis (yearly, monthly, daily, etc.); managed (where possible) from a coordinated platform based on common trading rules and shared operational standards; and
- **Implicit auctions:** provided that competitive wholesale markets are already in place on each interconnector's end, these should take place under progressively more efficient schemes, perhaps loose and tight volume coupling first, price coupling eventually.

The so-called HVDC (High Voltage Direct Current) 'super-grid' approach, devised to channel massive energy flows southwards from off-shore wind farms spreading over both North and Baltic Seas, could be therefore twinned, in a mirror image like way, by a corresponding northwards 'super grid' carrying sun power from Maghreb across the Mediterranean Sea.

Balancing obligations on renewable energy and the Role of the TSO in balancing

As indicated previously, renewable resources can be more difficult for the network SOs to manage than conventional technologies due to problems of intermittency and the need for back-up energy. SOs must consider challenges associated with:

- **Predictability:** the timing of the generation output of some of technologies cannot be accurately predicted;
- **Operation:** some of RES technologies are not easy to manage; and
- **Slow response time**.

In some countries involved in the MSP the network capacity is not strong enough to manage this new renewable energy, thus creating an extra barrier to new projects. One of the ways to manage this difficulty is to subject renewable generators to the same balancing obligation as conventional forms of generation. Renewable generators must be incentivised (obliged) to be balanced. The TSO is in charge of balancing. It achieves this through several balancing markets (e.g. secondary, tertiary, deviations) where the TSO operates as a 'single buyer'.

Technical requirements of TSOs for connecting and managing renewable generation

One of the risks in the implementation of the MSP is that the grid's security could be in danger. As the penetration rate of facilities using renewable energies rises, intermittency may become more of an issue which in turn will affect security of supply.

This is why requirements and incentives should be set to promote the provision of ancillary services and quality enhancements by renewable resources. These requirements and incentives can include:

- The obligatory assignment of generating facilities to control centres connected to the grid operator, and the ability to receive real time orders;
- The setting of economic incentives to control the generation and absorption of reactive power as an indirect means of controlling voltage. Large renewable generators must also be required to follow reactive power instructions from the TSO in real time;
- The obligation of some technologies to support voltage dips; e.g. that they are capable of remaining connected to the grid should its voltage fall whilst contributing, like other technologies, to the problem's resolution and to the grid's security and stability. This obligation can be mandatory for wind, solar and other technology, taking the technical possibilities into account; and
- The entitlement to voluntarily take part in other additional ancillary services.

Renewable energy access regulation and grid integration

It is important to develop connection procedures for renewable facilities. Non-discriminatory access rules and priority dispatch have to be established for electricity from renewable sources.

Members shall ensure that network operators in their territory guarantee the transmission and distribution of electricity produced from renewable energy. They shall also provide for non-discriminatory connection to the grid system of electricity produced from renewable energy. TSOs shall give dispatch priority with market based balance responsibility to generating installations using RES, always complying with the security of supply guarantee.

International rules shall clearly define any technical specifications which must be met by renewable equipment and systems in order to be connected to the grid and to benefit from support schemes. In order for TSOs to guarantee the security and the adequacy of the power systems installations, new generators which are connected to the grid will have to comply with the grid codes and technical specifications.

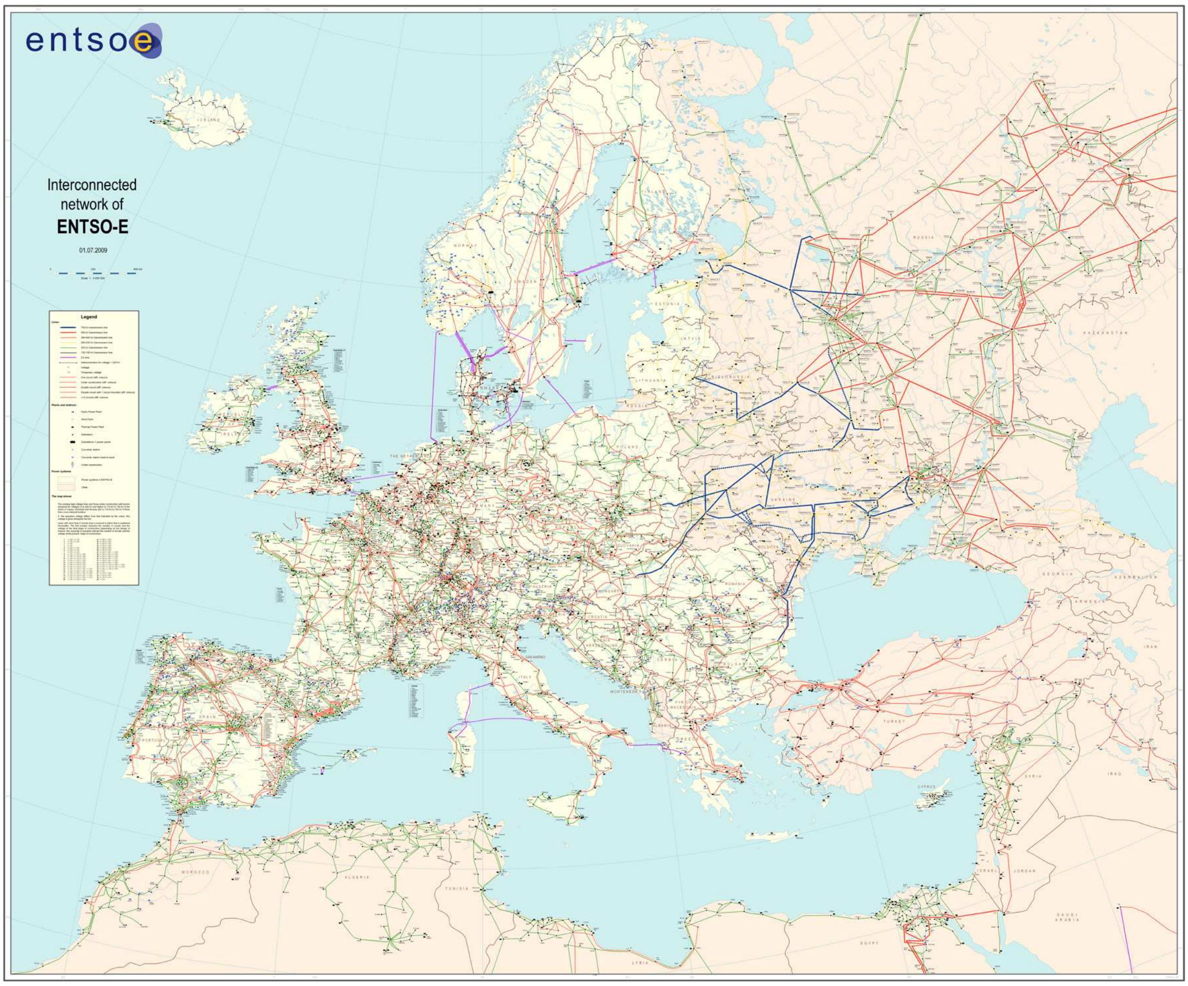
Transmission network development

The development of electricity produced from RES will increase the need for stronger grids and interconnection points.

To achieve the level of renewable penetration identified in the MSP targets, and to combine these targets with a guaranteed supply, it is necessary to create a strong network. A minimum network development therefore has to be developed in mandatory planning. In the development plans it is necessary to take into account that the network has to connect customers to the location of renewable resources. The advance in international grid interconnections and the promotion of international electricity markets will also help to achieve the targets. As a first step, it is necessary to identify the main links between the different regions involved. These links include the following interconnections:

- Morocco-Spain (operational)
- Morocco-Algeria (operational, reinforcement under preparation)
- Tunisia-Italy (under preparation)
- Tunisia-Libya (existing cables, but not operational)
- Turkey-Greece and Turkey-Bulgaria (existing cables, but not operational)
- Egypt-Libya (operational)
- Egypt-Jordan-Lebanon-Syria (operational)
- Egypt-Greece (under study)
- Syria-Turkey (partially operational)

Figure 7: European interconnected transmission network



Source: ENTSO-E (European Network of Transmission System Operators for electricity)

Currently, there is only an interconnection in the west part of the Mediterranean Sea (Spain-Morocco, with a maximum capacity of 600 MW), and some interconnections to the east (Turkey/Syria/Jordan/Egypt).

There is a significant bottleneck in the interconnection between Spain and the rest of the EU, with interconnector capacity of only 500 MW between Spain and France. Whilst this will increase to around 2800 MW in the near future this is still well below the 20 GW renewable generation target in the MSP.

This work will be carried out by the completion of the Mediterranean energy ring as a priority project. It will also be important to reinforce infrastructures between some European countries.

Supranational regulatory and legislative framework

To develop the MSP, integration of renewable energy from southern to northern countries would be impossible without first creating an integrated institutional and regulatory framework at an international level. This framework must be clear, transparent and contain a firm commitment to stability. The following points must be taken into account in order to create this framework:

1) Agreement between countries

A key factor is that relevant authorities from the origin and destination countries must establish a dialogue about infrastructures, cross border electricity exchanges, certification and regulatory issues in order to reach agreements to enable the transfer of renewable energy. It is necessary to receive a firm commitment from the participating countries to cooperate and share knowledge and experiences of renewable projects. Cooperation may also include transparency in exchange of information and best practices, such as national action plans, forecasts, national reports, etc.

It is also important to encourage the private sector in Mediterranean countries to invest in renewable energy by providing incentives and network access.

2) Share of renewable energy

When EU Member States join renewable projects with non EU countries, it is important that projects relate only to new capacity, so that producing countries do not end up exporting their renewable energy production and using fossil fuel for their domestic consumption. This will help to achieve the objective of not reducing the proportion of renewable energy in the total energy produced in the non EU countries.

Also, the project must define which proportion of the electricity generated will be for domestic use and which will be for export. This means that the energy produced could be shared between the EU and non EU countries, in order to achieve benefits for both parties so the countries which have the necessary technology would be able to invest in countries which have high renewable potential to improve generation efficiency.

3) Certification bodies

It is necessary to establish certification organisations in the participant countries, at a national level, with the international recognition of both EU and non EU members. These organisations must certify that the energy comes from renewable sources, according to established objectives and transparent criteria, and must also set transparent rules and appropriate controls.

4) Financing of the Mediterranean Solar Plan projects

Developing a strategy covering the suitable mechanisms for financing the projects is essential. The incentives must set out reasonable expectations for all parties, with developers and financiers making a ‘reasonable’ return. This will involve finding the most cost-effective solutions to ensure active private sector involvement.

Flexibility Mechanisms in Kyoto Protocol

The Kyoto and post-Kyoto protocols are initiatives contributing to the strategy for climate change mitigation. One of the flexibility mechanisms defined in the Kyoto protocol is the Clean Development Mechanism (CDM), a financial tool that is currently rarely used in the Mediterranean region.

The mechanism allows Annex I (developed) countries to invest in less developed countries in order to reduce the formers' CO_2 emissions. Developed countries can use these projects to obtain CO_2 emission rights, which can then be sold in a CO_2 emission rights market. For the developed country the main objective of the CDM is to avoid CO_2 emissions whilst developing the networks as cost effectively as possible.

This system benefits countries which have renewable energy potential but which lack the economic resources to carry out costly projects. New post-Kyoto mechanisms that will be implemented in the near future will provide further opportunities for new projects.

Flexibility mechanisms in the Directive 2009/28/CE

Directive 2009/28/EC of the European Parliament and the Council of 23 April 2009 on the promotion of the use of energy from renewable sources sets several flexibility mechanisms, which are useful for the MSP purposes.

The Directive facilitates a cross border trade of renewable energy that is compatible with national support schemes, in order to facilitate the achievement of mandatory national targets. The flexibility mechanisms are statistical transfers, joint projects between Member States and joint support schemes, all between EU countries.

Statistical transfers

This is an agreement between EU Member States. It sets out arrangements between a producer of renewable energy and a consumer of this energy.

There is a statistical transfer for a specified amount of renewable energy. For the producing country this energy is deducted from the total renewable energy in terms of its compliance with targets. For the consuming country the energy is added to the energy that is taken into account regarding compliance with targets.

Joint projects between Member States

This involves one of the Member States investing in new renewable generation plants located in other Member States. The amount of electricity produced from renewable sources is taken into account in determining compliance with the national targets of the first Member State. It is necessary for there to be interconnection lines between both countries for this mechanism to be enabled.

Joint support schemes

Two or more Member States can agree to coordinate their national support schemes. The participating members must set up a distribution rule to allocate amounts of energy from renewable sources between the countries.

According to this rule, the energy produced in one of the countries may count towards the national overall target of other participating country. Interconnection lines between countries are again necessary.

However, there is another flexibility mechanism which involves both EU and non-EU countries:

Joint projects between Member States and third countries

This flexibility mechanism is more suitable for the MSP projects.

In this mechanism, one Member State cooperates in a project located in a non EU country. The aim of the project must be the production of electricity from renewable sources. This cooperation may also involve private operators. It is possible to conduct joint projects in which several countries participate.

The electricity produced from renewable sources is then taken into account when measuring compliance with the national targets, provided the following requirements are met:

- Electricity produced must be consumed in the EU;
- Energy must be produced by a newly installed plant; and
- The electricity produced and exported has not received support from a third country other than investment aid granted to the installation.

Official Aid Development (ODA)

Access to electricity and other advanced forms of energy is an essential component in the fight against poverty and underdevelopment. Almost a third of the world's population completely lacks such access. In the face of this reality, the international community, the governments of different countries and a range of institutions have studied, planned and initiated several mechanisms to resolve this.

There are international organisations that could be involved in this task, such as the European Investment Bank, the World Bank and the various regional aid banks. International financial institutions may be willing to finance such projects through long term, low interest rate debt.

Private initiative

The essential role played by electricity supplies demands that the regulatory framework ensures profitability and the continuity of efficiently made private investments.

Systems based on electricity service concessions in rural areas are an appropriate model for efficient and continuous electricity supplies. The concession scheme is attractive for large private companies, local companies, cooperatives and other organisations within the community which benefits from it.

The concession model facilitates the creation of sufficiently large markets as a guarantee for business sustainability and in order to extend and ensure electricity supplies to as many consumers as possible.

One example is the Desertec Industrial Initiative. The aim of this initiative is to start supplying electricity to the EU and to generate sufficient power to meet the needs of the producer countries as soon as possible. The focus of the Desertec initiative in the field of power generation will be on sun and wind as renewable sources of energy. This initiative will be financed by contributions from participating companies. Additional funds may be raised from public sources.

Socio-economic impacts of the Mediterranean Solar Plan

There is no doubt that renewable resources have extensive advantages. Nonetheless, renewable resources also suffer from disadvantages when compared to fossil fuels. These disadvantages arise from greater investment costs, the dispersion of energy sources and the intermittency of some technologies, which lead to higher costs when utilising the energy.

Effective regulation is fundamental to guide the energy model towards sustainability, especially in liberalised energy frameworks, so that market failures are reduced or minimised when regulatory mechanisms are introduced. In this context, there are some risks to take into account when developing the MSP. Some of these risks are:

1) EU countries being passive

The delay of some EU countries in adapting European regulations regarding climate change, renewable energy standards, energy efficiency, etc., can be an extra difficulty in extending investments in non EU countries.

2) Difficulty of designing an adequate supranational support scheme

Establishing an adequate support scheme for different countries is a complex task. Over-pricing support results in windfall profits for generators and extra costs for consumers. One of the key features of an adequate scheme is stability and predictability of economic incentives as it reduces regulatory uncertainty. This incentivises investments in new capacity and, at the same time, minimises financing costs and hence final costs to consumers.

3) Increase in electric energy prices

Renewable energy technologies are highly capital intensive and they can be especially expensive in developing countries. Greater investment costs, dispersion of energy sources and the intermittency of some technologies could lead to higher costs of the renewable energy. With the increasing proportion of the energy mix coming from renewable sources, and without adequate investment plans, the final price of electricity could be unnecessarily high.

4) Geopolitical barriers

Achieving MSP targets requires political commitment between countries. Energy is usually regarded as a national issue. Countries and industries do not always have the same end goal. This lack of convergence often leads to strong political reactions from member countries and their industries. To counteract this kind of barrier the private sector should play the main role in investing in, managing and operating projects in order to reduce the geopolitical influence.

General benefits of the Mediterranean Solar Plan

The MSP is a positive response to the energy and climate challenges of the Euro-Mediterranean region. All the countries involved will face major energy and climate challenges in the near future and the use of energy from renewable sources constitutes an important part of the measures needed to meet the commitments.

Renewable resources have extensive advantages for society in relation to: industry, employment, development, checking the deterioration of trade balances, security of supply, and improvements in environmental quality. The combined effect of these advantages is a move towards sustainable development. Other specific benefits from the MSP are:

1) Optimising natural resources

If the mechanisms to promote renewables are extended to a supranational level, the areas with more electricity potential will be in the best position to receive support. Investments should therefore be directed to where they will be most effective.

2) Improving efficiency

Efficiency (comparison of the total amount of support received and the generation cost) improves in a supranational promotion mechanism, and the system is more cost effective for consumers.

3) Improving effectiveness

Effectiveness (ability to deliver an increase of the share of renewable electricity according to a potential reference point) is higher when investment goes where the best resources are located.

The potential benefits of installing renewable plants in developing countries with a stable and clear international regulatory framework will attract investments from developed countries, as discussed below.

Benefits for EU countries

1) Achieving national targets in an efficient way

In the European directive 2009/28/CE some mandatory targets are defined with a target of at least a 20% share of energy from renewable sources in the Community's gross final consumption of energy in 2020. This general target is set in several specific mandatory national targets for each member state.

With the promotion of the MSP and the resulting increase in renewable energy coming to the EU, renewable electricity from non EU countries will help the EU countries to achieve their targets. Also, with the high efficiency of the MSP, these targets will be reached at a lower cost.

2) Reinforcing the relationships between countries in the Mediterranean Region

The states and governments of the European and Mediterranean countries will cooperate in the development of this plan. This fact will reinforce the cooperation between the two shores of the Mediterranean Sea.

3) Benefits for private companies and investors

Most of the projects involved in the MSP will be developed by private companies with headquarters located in EU countries, with the consequent benefits for these countries.

Benefits for non-EU countries

1) Technology transfer

The MSP will foster and encourage the transfer of technology to developing countries in order to strengthen skills in the domain of renewable energy and energy efficiency.

2) Benefits for society

Typical advantages of renewable energy include benefits for the societies where resources are located. As these resources are usually located far from the existing network, this will increase the number of citizens with access to electricity, and assist in the country's development.

Renewable resources also contribute to creating quality jobs and improving industrial competitiveness. Hence the policies that encourage renewable generation can contribute to a country's long term economic growth plan.

3) Other benefits

The implementation of the MSP will have additional benefits for the countries where these facilities are located, such as security of supply, trade balance, improvements in environmental quality and reduction of energy dependence.

Conclusions

The MSP has the potential to be an important vector for sustainable development in the area, and involves significant benefits for all Union for Mediterranean Countries.

On the other hand, it is a complex project and there are some risks and difficulties to identify and face in order to achieve the targets. The MSP will not be possible if it does not include a firm commitment by the EU and non EU countries to cooperate in a win-win approach.

5. Overview of regulatory issues related to distributed generation

5.1 Introduction

During the last decade there have been significant changes in the regulatory frameworks of several countries in the world and this has encouraged a sharp increase in Distributed Generation (DG) in electric power systems. The objective of these regulatory changes is the development, promotion and exploitation of DG. As a result of these changes, technological and environmental challenges must also be considered.

The objectives for the changes include:

- **Energy efficiency:** the efficient use of RES benefits all operations within electricity systems;
- **Research and development:** the exploitation of these resources promotes research and development of new technologies of electricity generation;
- **Climate change:** the exploitation of non-polluting or low-polluting resources reduces the emission of greenhouse gas effects, especially CO_2;
- **Design of market mechanisms:** the integration of DG into existing electricity systems poses important challenges for markets. This is especially true of intermittent distributed generation and its interface with conventional transmission capacity. It also creates issues related to the interconnection between systems;
- **Reduction of losses in distribution and transmission grids:** locating generation closer to the points of consumption helps to decrease losses in the transmission lines. The cost of building new grids and reinforcing the existing ones can be minimised with DG; and
- **Enhancement of supply reliability:** DG offers a variety of production technologies that tend to reduce dependence on external energy and to increase the use of indigenous energy sources.

Regulation plays an important role in managing the transition to more DG. Many countries represented in ICER have begun to modernise and expand their regulatory frameworks, in order to establish an environment that promotes the optimal utilisation of DG.

Regulatory reform is intended to create the competitive conditions necessary to promote DG in a market environment, through the establishment of incentives that make DG a viable alternative to conventional generation. Such reform can serve different purposes in different settings. For example, the transmission capacity associated with DG, may be managed in some countries so as to encourage the expansion of conventional transmission capacity. In other settings it could be important to incentivise an increase in the interconnection capacity to promote international transactions.

Another example is the adoption of regulations that offer incentives for the entry of new DG alternatives, such as wind power generation. In other cases regulatory reform is intended to promote systems that complement diverse technologies, such as wind energy storage systems. In both these examples, the regulatory design has to be able to give the economic signals for the development of investments.

This chapter illustrates the respective experience related to distributed generation in Namibia (AFUR) and Guatemala and Spain (ARIAE, in Spanish). The chapter seeks to contextualise how these experiences have contributed to the promotion of distributed generation and how exogenous factors, related to the market, have influenced its future development. The chapter also presents issues faced by distributed generation and measures that ICER member countries have adopted to promote its integration.

5.2 Case study 9: Namibian biomass power project, CBEND

Introduction

In 2007 Namibia had a population of slightly over two million inhabitants, with energy production of 0.33 Mtoe, net imports of 1.23 Mtoe and electricity consumption of 3.6 TWh.[85] An estimated 80% of the rural population relies on wood fuel and this has been one of the major causes of deforestation in the country. Namibia does not produce any domestic petroleum or coal products.

The existing grid network currently supplies about 30% of the rural population, and well over 90% of the urban population, with a small minority lacking access as a result of mushrooming informal peri-urban settlements stemming from rural to urban migration. The key players in electricity supply and distribution are NamPower, the Regional Electricity Distributors (REDs) and local authorities. The current market structure is that of a vertically integrated single buyer: NamPower's electricity trading unit buys electricity from its generation units and independent power producers (IPPs) through long term power purchase agreements (PPAs). It then sells it to REDs, municipalities and local authorities. The PPA is a result of bilateral negotiations between the IPP and NamPower.

The electricity supply mix is made up of a combination of domestic hydropower and thermal energy combined with imports from the Southern Africa Power Pool member countries: Mozambique, South Africa, Zambia and Zimbabwe. For the period 2000 - 09 the contribution of electricity imports to the national energy requirements averaged 49.8% annually, varying from 36% in 2000 to 60% in 2009. For the same period, domestic generation averaged 50.2% and varied from 64% in 2000 to 40% in 2009.[86]

Namibia and the Southern African Power Pool have been experiencing a severe power deficit since the beginning of 2008. Namibia has an installed capacity of 386 MW comprising 240 MW Ruacana (hydro), 120 MW Van Eck (coal) and 26 MW Paratus (diesel). The 386

[85] NamPower 2007 Annual Report (http://www.nampower.com.na/Pages/annual-report.asp).

[86] Derived from NamPower and ECB Annual Reports.

MW internal capacity is against a peak demand of 443 MW (excluding zinc scorpion mine) in 2009.[87] The supply deficit has been filled by imports from the Southern Africa Power Pool. The interconnector with South Africa is capable of carrying 600 MW, whilst the newly constructed HVDC Caprivi Link Inter-Connector is a 300 MW bipolar line and upgradeable to 600 MW.

Electrical energy units into NamPower system in the past three years have been 3,621 GWh, 3,719 GWh and 3,692 GWh in 2007, 08 and 09 respectively. The drop in energy delivered into the system in 2009 compared to 2008 may be attributed to demand side management measures and impacts of the economic downturn in the mining sector, particularly the sharp drop in demand and commodity prices of diamonds. For the longer term, Namibia is looking to build its domestic portfolio with renewable energy, coal and gas (Kudu Gas Project). The proposed Baines hydropower station on the Kunene River is at the feasibility study stage. Namibia also has a hydro energy resource development master plan based on studies performed on its major rivers.

Renewable energy and power generation in Namibia

Namibia is well endowed with natural energy resources. Non-renewable energy resources are gas and uranium, both of which are a technical challenge to exploit to provide power to the country. The renewable resources are in the form of wind (measuring 6-8 m/s along the coast), excellent solar radiation (above 2200 kWh/m^2/year according to Atlas of Namibia Project, 2002) and biomass material, which is invading prime grazing land (over 26 million hectares). The use of renewable energy resources is for “maximum social and economic benefit, taking into account long term environmental concerns while giving priority attention to the country’s development needs” (White Paper on Energy Policy of 1998, p. 43).

The Third National Development Plan (NDP III) framework advocates the energy subsector providing an adequate, secure and efficient supply of energy that is environmentally friendly and leads to a reduction in the country’s reliance on energy imports. NDP III proposes the following strategies to meet that objective:

- Increasing local energy generation with conventional and renewable technologies and strengthening distribution networks;
- Improving the regulatory framework through the establishment of a strong regulatory body for the whole energy subsector;
- Establishing a commercial electricity trading centre and enforcing regionally harmonised tariffs for cost recovery;
- Implementing the Rural Electricity Distribution Master Plan and providing remote areas with off-grid renewable energy;
- Extending the urban electricity network and promoting renewable energy in the urban areas;

[87] NamPower Annual Report, 2009.

- Promoting the efficient use of energy by introducing special technology programs and public awareness campaigns; and
- Increasing local capacity.

Despite the abundance of various RES in Namibia only solar technologies have gained relative market access, although their use is limited to off-grid energisation and domestic water heating. This is despite several licence applications being launched and approved by the Electricity Control Board (ECB) for wind power development. These license applications are at the forefront of several discussions and proposals being submitted to the Ministry of Mines and Energy and other electricity supply industry stakeholders.

The optimum utilisation of RES requires a combination of appropriate policies, regulatory frameworks, appropriate technology and detailed technical information for easy decision making. The white paper on Energy Policy of 1998 and the NDP III policy frameworks are very clear that the government supports renewable energy. However, Namibia has no renewable energy policy. There is also limited bankable energy resource data for both smart and targeted renewable energy policy development and renewable energy developers. The present regulatory environment neither provides favourable market access for renewables nor does it facilitate distributed generation to off-grid areas. This is in spite of Namibia being sparsely populated and it being economically unfeasible to extend the grid to remote communities. The local institutional framework encompassing the financial sector, technology providers and human capital is not adequately prepared for, nor focused on, large scale renewable energy development. The financial sector is small and also lacks capacity to finance 'riskier' renewables projects, while the training of engineers for the renewables sector is still in its infancy.

One of the major obstacles to the large scale development of renewable projects is the absence of pricing mechanisms for these resources, despite the policy intentions as outlined in the White Paper on Energy Policy of 1998, the IPP framework, and others. Other countries that have experienced large scale development in Renewable Energy Technologies (RETs) like China, Germany, Spain and Sri Lanka have introduced support mechanisms such as: feed-in tariffs, quota systems and obligations (the latter sometimes in parallel with feed-in tariffs). South Africa introduced feed-in tariffs in March 2009 though its impact is yet to be felt. The support mechanisms are designed to ensure access of RES to the grid at a fair price, as well as to meet other supplementary objectives.

Creating a level playing field for renewable energy technologies includes eliminating market and policy failures such as price ceilings on electricity and subsidies for grid-based electrification. As long as these market failures persist, renewable energy technologies are systematically and unfairly discriminated against. Appropriate institutions and skilful interweaving of technology, economics and politics are needed to overcome this barrier in Namibia.

The Namibian biomass power project, entitled Combating Bush Encroachment for Namibia's Development (CBEND), is a proof-of-concept project which will identify, procure and install one bush to electricity power generating plant in a densely bush encroached area of the country. The plant will generate approximately 250kW. The project, implemented by the Desert Research Foundation of Namibia, was inaugurated in September 2010. Fuel for the power plant is derived from harvested invader bush, mainly using bush thinning rather than bush clearing techniques, and electricity produced is supplied to the national grid. The energy conversion technology used is wood gasification. Although the project dedicates significant resources towards infrastructure, considerable activities also focus on enhancing livelihoods for rural communities. This improves the efficiency of bush harvesting, develops the scope for small and medium enterprises and establishing a commercially operated small IPP.

CBEND Trust, a not-for-profit organisation, is the legal owner of all equipment and assets procured under the EU funded CBEND project and of Bush Energy Namibia (Pty) Ltd. The latter leases equipment and assets from the CBEND Trust and operates as an IPP with a provisional license granted by ECB.

Market arrangements

The CBEND project was developed and is being implemented as a proof-of-concept project. The project fulfilled all regulatory requirements for plant installation and operation. The requirements include a generation licence as an independent power producer from the ECB; an environmental clearance (which is a generation license condition) from the Directorate of Environmental Affairs; and other legal aspects such as a long term lease agreement between the landowner and the CBEND Trust as well as a power purchase agreement with NamPower (the state owned utility).

The electricity from the 250 kW power plant is wheeled (transmitted) through the distribution network to NamPower’s transmission network where the utility is the off-taker. A special feed-in tariff was negotiated and granted with the off-taker. The power plant has priority of dispatch.

Network arrangements

The power plant supplies power to the offtaker at transmission level through the distribution network. The distribution line required reinforcement through power factor correction which was implemented by the distributor, Central Northern Regional Electricity Distribution Company. CBEND paid for the grid access technology, including metering. The plant is too small to pose serious technical interconnection and operational challenges.

However, if similar power plants are located at the distribution level, they will still face technical challenges related to grid reinforcement. NamPower’s purchasing power agreements for IPPs embedded in the distribution network, involve back-to-back metering with one meter for IPP sales to NamPower and the other meter for sales of the same power to the distribution company by NamPower. This means that no transmission charges are paid to the distribution company.

Distributed generation

The CBEND project is a typical distributed generation project designed to supply power at the distribution level. The project was designed to bring rural social improvement and to address the prevalence of bush encroachment through wood gasification for electricity generation. These are significant steps in a country with unemployment levels of 51.2%,[88] rural electrification rates of around 30% and bush infestation of 26 mn hectares of prime agricultural land. It can be seen that power generation was not the only objective of CBEND. The concept, however, experimented on small distributed power generation based on wood gasification technology. It is clear that in the absence of an appropriate regulatory framework for renewable energy based grid-in-feed systems the replication of CBEND like project on commercial basis is impossible.

The lack of an appropriate regulatory framework is the main reason solar based electricity has not been integrated into the grid but rather confined to off-grid applications. The application of solar in off-grid applications is driven by economics, demand for energy and an enabling policy framework, the Off-Grid Energisation Master Plan.

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5.3 Case study 10: Considerations of the experiences of Guatemala and Spain

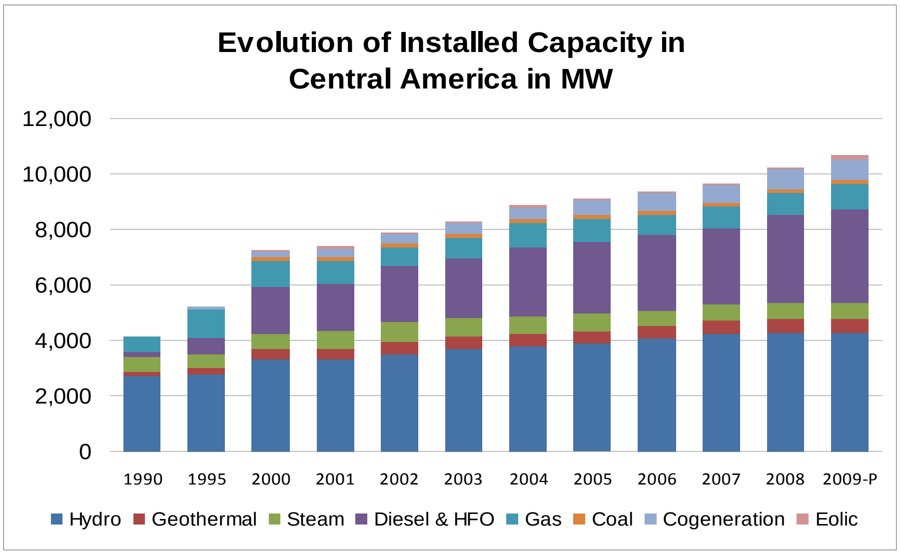
There have been significant changes in the regulatory frameworks in several countries of Latin America during the last decade – all of which have been designed to encourage distributed generation in respective electricity systems. Nonetheless important issues remain unresolved.

[88] Namibia Labour Force Survey, 2008.

For many of these countries, the use of this kind of generation has become an important tool to reduce dependence on fossil fuels. This effort also serves to reduce greenhouse gas emissions, with the object of meeting environmental regulations.

Many of the countries represented by ARIAE have enough potential to cover their demand using renewable resources. However, unfortunately, many of them depend heavily on fossil fuels to produce the electricity they need. This is illustrated in Figure 8 with respect to the Central American countries. There has been an increase in the proportion of fossil fuels such as diesel and heavy fuel oil (HFO) (bunker) in the production of energy in recent years, in spite of the huge potential in the region to generate energy from renewable resources.

Figure 8: Installed electricity capacity in Central America



Source: CEPAL 2009[89]

Figure 8 shows that the proportion of the growth in the installed capacity of generation based on diesel and heavy fuel oil has increased in the last 20 years by almost 600% in the Central American region. The fuel mix has changed very significantly since 1985, when most of the electricity was produced from renewable hydro resources.

[89] Central America: Statistics of the Electrical Subsector, 2009, Economy Commission for Latin America and the Caribbean CEPAL.

This shift in the generation mix has been caused by several factors, which are beyond the scope of this document. However, some other countries have been successful in producing renewable energy and promoting the development of new renewable generation plants, as well as the development of distributed generation. The objective of this case study is to identify the challenges that still need to be addressed so that distributed generation develops in a dynamic and integrated way. We analyse some of the experiences in Guatemala and Spain related to the following topics:

- **Connection and integration**
  - What basic equipment is needed to guarantee the effective connection and disconnection of distributed generation?
  - How can distributors be incentivised to connect distributed generation to their grids?
- **Operational concerns**
  - Should the operation of distributed generation be carried out by a central institution?
  - What is the impact of distributed generation on the operation of the distribution grid?
- **Market issues**
  - What are the options for distributed generation to commercialise its energy?
  - Can distributed generation offer other products in the market, such as ancillary services? If so, under what conditions?
  - How should losses be accounted for when distributed generation helps to reduce them?
  - How should losses be accounted for when distributed generation is connected far away from the load centres?
- **Access to information**
  - How can information barriers regarding distributed generation (intended as distributed generation non-connected to the grid, e.g. isolated distributed generation) be eliminated?
  - What information should be available for those investors interested in developing projects of distributed generation?

Connection and integration of distributed renewable generation to the distribution grids

Technical criteria

When new generation plants connect or require access to the distribution grids there are two important considerations. On the one hand, the distribution company is interested in a regulatory framework which promotes investments in distributed generation, and which recognises the potential to minimise losses in distribution and to increase the reliability of the grids. While on the other hand, distributed generators are interested in clear technical criteria and standards for the connection, and a methodology which quantifies consequential costs associated with necessary grid reinforcement.

In **Guatemala**, the Technical Standard of Distributed Renewable Generation (NTGDR in Spanish) outlines the procedure that regulates the connection of distributed generators to the distribution grids, according to a study of capacity and connection prepared by the distributor. The study is a technical evaluation that measures the impact of the connection. Additionally, it is important to note that Guatemalan legislation obliges distribution and transmission companies to give free access to their infrastructure to any interested parties.

The study is used to support the approval of the connection of the distributed generator, where the connection does not require any associated consequential expansion or modification to the connection point. If this is not the case, the study identifies the nature of the expansions and/or modifications required for the connection.

In both cases, the study has to document the benefits (if any) of the expected improvement in the parameters of quality of service after the connection. According to the NTGDR, the only cases in which the distributor can deny access to the distribution grids are those where the study indicates a lack of capacity in the distribution grid, a situation that should be corrected by reinforcements of the grid.

The capacity and connection study allows the distributed generator to make a clear cost evaluation of connection to the distribution grid. In cases where such costs exceed their economic capacity and compromise the development of the project, the distributors can identify possible options that allow them to develop an integrated plan that considers distributed generation as an alternative to the expansion of their grids.

In **Spain,** the Electric Sector Law liberalises generation and commercialization activities, as long as transmission and distribution grids are operating in the natural monopoly regime. They are liberalised by giving third parties access to the grid. Access to the grid is thus a right of producers, and is regulated through a specific standard, which controls the following factors (among others):

- Right of access to the grids is only restricted to generators when there is a risk to the electricity supply;
- In case of a surplus of generation capacity installation, the possible congestions should be resolved in the short and medium term, by the corresponding technical solutions (mechanisms of remote control, remote trip, etc.);
- In the long term, congestions should be solved by planning (and eventually the regulation of distribution) so that these events do not become chronic;

- The principle of capacity reserve is currently valid in the Spanish legislation. Any request for new capacity should be honoured when there is capacity at the point in the grid to be connected, regardless of whether, once the construction is finished, there could be a limitation in the production supply to the grid;
- The generator has to cover the costs related to infrastructure enhancements necessitated by the connection to the distribution or transmission grid. Such costs will be shared by new generators who use those connection installations during the next five years;
- The operator of the transmission or distribution grid has to make a specific study of each access request, establishing the concrete technical requirements of the connection; and
- Access conflicts are resolved by the Spanish energy regulator, Comisión Nacional de Energía (National Energy Commission). If the conflict concerns specific technical aspects of the connection it is resolved by the corresponding Comunidad Autónoma (regional government).

Basic equipment for operation, protection and maintenance

Since the distributed generation proposal usually includes a description of the type and size of the generators to be installed, taking into account the specific relevant characteristics of the distribution grid, it is not possible to have a 'one size fits all' concept that defines this kind of generation properly in every aspect.

However, the basic equipment used for the operation of distributed generation, as well as the technical criteria for the connection, will depend on the requirements of the grid. The criteria for the selection of this basic equipment for the operation, protection and maintenance of the generators are not always regulated or prescribed.

In the case of **Guatemala**, the NTGDR regulates the minimum required equipment for the connection of the distributed generators depending on their capacity. It considers the design of the distribution grid,[90] but reserves a margin of slack capacity that will depend on the specific characteristics of the grid to which the generators will be connected.

Table 5 shows the connection requirements of the generators in Guatemala, which vary according to their capacity and also to their configuration in the grids. The framework allows the installation of distributed generators in single phase distribution grids when their capacity is not higher than 50 kW.

The regulation of the equipment used for operation, protection and maintenance, according to the minimum requirements for the connection of the distributed generators, helps to

[90] In Guatemala, the distribution of single-phase energy is widely used, especially in rural areas, where the cost of a three-phase distribution grid is high and the use of three-phase loads are less frequent.

eliminate uncertainty and the lack of transparency in the development of distributed generation. This promotes appropriate access to the distribution grids and optimises the benefits of such projects.

New approach in the planning and design of the distribution grids

The access of generation projects to distribution grids is increasing, which motivates distributors to face new challenges in the planning, operation and maintenance of their facilities.

The Distribution System Operator plays an important role in the implementation of the mechanisms designed to respond to these indicators.

European Directive 2003/54 CE Article 14.7 states that "when planning the development of the distribution grid, the operator has to review the measures of energy efficiency and energy demand management or distributed generation that can supply the need to increase or substitute the energy capacity."[91]

[91] Directive 2003/54/CE of the European Parliament as of 26 June 2003.

Table 5: Requirements for the connection of distributed generators in Guatemala[92]

Type of connection	Capacity [kW]			
	Single-phase	Three-phase		
Characteristics	**< 50 kW**	**< 500 kW**	**500 kW - <2000 kW**	**2000 kW - 5000 kW**
Interruption device (capacity to interrupt the maximum short circuit current)	X	X	X	-4
Interconnection disconnect device (manual, block, visible, accessible)	X	X	X	X
Generator disconnect device	X	X	X	X
Overload trip	X	X	X	X
Low voltage trip	X	X	X	X
High/low frequency trip	X	X	X	X
Synchronism check (A: Automatic, M: Manual)	X-A/M (1)	X-A/M (1)	X-A (1)	X-A (1)
Overcurrent to ground trip		X (2)	X (2)	X (2)
Inverse power trip		X (3)	X (3)	X (3)
For energy export, function for power direction can be used to block or delay a trip due to low frequency			X	X
Telemetry/transfer trip				X
Automatic voltage regulator (AVR)				X (1)

Guatemala and **Spain** have both implemented regulatory and market mechanisms that allow the promotion of a generation reserve margin which guarantees that demand can be met at all times. These mechanisms assume that the transmission grid does not impose any restrictions on the balance between generation and demand.

However, this is not the case for local demand. Here the absence of distributed generation due to failure or interruption can lead to overloads or low voltage problems in the distribution grids. These grids have an important role in the balance of generation and demand, so it is crucial to consider distributed generation planning in an integral way.

[92] Chapter 2: Electrical equipment required for the connection, NTGDR.

This scheme presents important challenges for the regulatory institutions. For distributed generation to be considered as an alternative to investment in new installations it has to guarantee its production, especially in high demand conditions. Currently, a distributed generator has no incentive to guarantee its production in the system. This forces the distributor to size its distribution grid as if such generation does not exist, which is not optimal.

New investments to allow distributed renewable generation

The distributors have to remain vigilant regarding demand growth projections for future years. Moreover, in accordance with those projections, they have to plan their required investments so as to meet the anticipated demand growth and ensure the continuity of energy supply and maintain or improve reliability performance.

Distributors currently face the problem of choosing between investing to meet their net demand (without considering distributed generation) or to invest to meet gross demand. If the distributor chooses the former, the generator might decide not to generate in case of a failure, a discharge, or because it is not economically profitable for it to do so. This increases the possibility of overload in the grids or even the interruption of energy supply, because not all the demand can be satisfied.

Usually the investments in distribution grids consider decision factors such as the maximum capacity in each element, voltage loss and voltage regulation. Some studies have demonstrated that distributed generation has the potential to delay investments in the grids.[93] Typically the rise in generation capacity reduces the probability of overloads and low voltages in the grids.

To illustrate this with an example, consider the case of a grid in Castilla La Mancha, Spain. It has a 132/45 kV transformer with a capacity of 30 MVA, and supplies energy to a zone in which a generator operates.

Records of the operation of the transformer show that for 1% of its operation time in a year (in conditions of high demand) the transformer experienced a net demand that led to a loadability of 90% of its capacity, 27 MVA. During the same period, the distributed generator had a yearly production of 12.5 MVA.

Considering the brute demand, without considering distributed generation, the transformer operated above its capacity (~32.5MVA). It should be noted that the transformer operated above its capacity in the absence of a distributed generator. This is why a second transformer of 132/45kV, 30 MVA was installed to alleviate the initial overload.

The new regulatory framework in Spain related to the reimbursement of the distribution activity is established by Royal Decree 222/2008. A new grid reference model is created in

[93] Méndez Quezada, 2005.

this standard, which is based on actual consumption and the distributed generation. Thus costs associated with expansions of the grid are guaranteed for reimbursement.

The distributor in Spain has ceased its involvement in the activity of commercialisation of energy to become the operator of the grid. Its objective is to manage the changing flows in an optimised manner. Such changes arise from the contribution of distributed generation and also from demand management measures, implemented through the advent of smart metering and new projects such as electric vehicles.

It may be that further regulatory change should be implemented to promote the operation of distributed generation in hours of peak demand.

Technical operation of distributed renewable generation

In order to take full advantage of the grid the operator must consider technical aspects such as the reduction of overload probability, the improvement of voltage profiles, the reduction of losses and improvement in reliability. Distributed generation has a direct impact in each of those aspects, which are analysed here in light of the experiences in Spain and Guatemala.

Losses

In **Guatemala**, the tariff for regulated users is calculated using the weighted price of all the purchases of capacity and energy made by the distributor, using the Distribution Aggregated Value (VAD in Spanish). This is equal to the mean reference cost of capital and operation of the grid for an efficient company in an area of a certain density. During the calculation of VAD, among other components, the mean distribution losses are integrated, so that they are accounted for in the tariff. The distributor has to assume such losses.

As for the losses in transmission related to distributors, there is a charge for losses from which the excess of nodal prices has to be subtracted, plus the charges for losses related to the capacity contracts used by the distributor to purchase in the node of a certain generation plant.[94]

This regulatory mechanism has a clear incentive for the reduction of losses, because VAD considers the mean losses of distributors and they can liquidate real losses. For instance, if the real losses are less than the mean losses calculated in the VAD, the distributor gets an economic benefit.

In this way, the presence of distributed generators in the distribution grids is considered in the reimbursement to distributors. Accordingly they are incentivised to reduce losses in the grids.

Quality of service

[94] Commercial Coordination Standard Number 11 (Wholesale Cost Report) of the Wholesale Market Administrator (AMM in Spanish).

In relation to quality of service, Guatemala and Spain have similar standards for the regulation of commercial and product quality.[95] This section covers some important considerations about product quality. Commercial quality will be discussed in the section on access to information.

The transmission network has to guarantee the stability and safety of the system, while the distribution grid is responsible for product quality as received by the final users.

The most characteristic events or disturbances related to product quality are variations in frequency, harmonics, flicker, voltage fluctuations, brief voltage interruptions, over-voltage and current imbalance. Although distributed generation has some influence on these events, the most important impact it has is with respect to brief voltage interruptions.

In **Spain**, there are technical standards that force small installations of distributed generation to disconnect from the distribution grids in the event of sudden and fleeting voltage interruptions.[96] However, quality of service meets the regulated levels in the large majority of cases, so there rarely a need to apply such a standard.

Also in Spain, the regulation, in Royal Decrees 661/2007 and more recently 1565/2010, provides that wind power and photovoltaic solar technology installations of a certain installed capacity should stay connected during voltage loss.[97] This means that they should be capable of staying connected to the grid in the event of a voltage loss in the grid thereby improving the quality and safety of the system.

In **Guatemala**, since distributed generation is still in the promotion phase following the recent release of the Distributed Renewable Generation Technical Standard, the operation of distribution systems has not yet shown any generalised problems because of voltage interruptions. Generally, product quality is regulated by the technical standards relative to the quality of the supply in the existing distribution installations.

Reliability

Reliability in the distribution grid, also known as continuity of service, is regulated according to the frequency and time of interruption of the electric energy supply.

Guatemala and **Spain** have similar regulations respecting the continuity of service.[98] The impact of distributed generation is related to two important topics:

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[95] In the case of Guatemala, the Technical Standards of Distribution Service (NTSD in Spanish); in the case of Spain, the UNE-EN 50160 of 1994 standard is used.

[96] Orden ministerial de 1985 BOE 12-9-1985, núm. 219, [pág. 28810].

[97] P.O.12.3: Requirements of response in case of tension loss in installations of special regime production.

[98] In the case of Guatemala, the Technical Standard of Service Quality of the Transmission System and Sanctions (NTCSTS in Spanish). In the case of Spain if is legislated by Royal Decree 1955-2000 and order ECO 797-2002.

- The possibility of generation working in islanding operation mode, improving reliability; and
- The repercussion in the operation in the occurrence of n-1 contingencies.

It is evident that the creation of mechanisms that allow the success of an ancillary services market for distributed generation, such as black start, promotes the use of synergies to improve the reliability rates in the operation of distribution systems. This topic will be seen in detail in the section Market Issues Related to Distributed Renewable Generation.

Voltage regulation

The impact of distributed generation from the point of view of voltage regulation will depend on the quantity and type of installed generation. From a purely technical point of view, the generators have the capacity to deliver or receive reactive power to or from the grids where they are connected. This has a direct impact on establishing the voltage profiles at the different points in the grid.

In relation to voltage regulation, **Guatemala** imposes technical standards that apply to distribution installations, with no distinction between conventional installations or those related to distributed generation. Generators have to operate with values of power factor very close to one.

In the case of **Spain**, current legislation creates an incentive framework for generators in the regulation of power factor, which increases the safety of the system. This topic will be discussed in detail later on in the document.

Market issues related to distributed renewable generation

Energy commercialisation

Regulation of commercialisation is a strategic topic that plays a crucial role in the design of regulatory mechanisms governing distributed generation. Here we discuss the experience that **Guatemala** has had in this area.

According to current regulations, distributed generation can sell its production in two ways which are not mutually exclusive:

- In bilateral contracts (with distributors, large users or traders); and
- In the wholesale market.

In order to promote distributed generation, the regulator has the opportunity to issue terms of reference to allow distributors to have auction events to procure capacity and energy blocks.

Requirements for participation in the wholesale market

For generators to qualify to participate in the wholesale market or in the bid events held by distributors, they must declare a firm offer that is calculated considering its maximum capacity and its availability. They also have to declare an efficient firm offer, which is an operative procedure that calculates the capacity that a generator can guarantee. This is calculated using its firm offer and its economic efficiency.

The system operator is currently designing a simplified procedure to calculate the firm offer of distributed generators, which is yet to be approved by the regulator.

Contracts with distribution companies

It is important to note that the new regulation governing distributed generation reduces the previously existing asymmetries between large and small generators, since the generators that participate in the wholesale market can subscribe to contracts with the distributors and the rest of participants in the wholesale market on equal terms.

The distributors are currently promoting a bid for capacity and energy purchase to cover their long term demand.[99] This bid considers the possibility of procuring distributed generation according to the current regulatory framework.

Guatemala: Long term bid to procure energy and capacity

The regulatory framework requires that distributors procure their total capacity and energy requirements through open bids. This is possible after recent modifications to the regulatory framework. Distributors can add new generation to the system this way, to guarantee an efficient electric energy supply to their final users in the long term.

The amount of capacity and energy in the long term was accumulated by the distributors to create a purchase volume that can reflect competitive conditions in the prices, to the benefit of final users.

The bid meets the needs of the generation expansion plan which seeks to promote the exploitation of RES dispersed throughout Guatemala. It also promotes the use of more efficient generation technologies that can transform the energy matrix in order to supply efficient electric energy to final users.

The object of the bid is to procure up to 800 MW of guaranteed capacity for the distributors, which will be used to supply energy to final users for a term of up to fifteen years, starting from 1 May 2015.

The bid is based on a system of quotas to procure capacity and energy. These quotes were designed to meet congruent strategic objectives of the national energy policy. In the case of capacity, the system of quotas establishes that from the 800 MW that distributors have to procure at least 480 MW (60%) from renewable resources, including distributed renewable generation. This situation reflects a clear incentive to the installation of new plants of distributed renewable generation and an increase in the participation of this kind of generation in the national energy matrix.

In the case of energy, the system of quotas also establishes that distributors have to procure up to 20% of their long term energy requirements from wind power, solar or other plants that are recognised as distributed generation by the Distributed Renewable Generation Technical Standard. This quota was designed specifically to promote generation projects with

[99] Resolution CNEE-185-2010 includes the terms of reference used by distributors to issue the terms for open bid PEG-1-2010.

renewable resources based in non-conventional technologies[100] and distributed generation projects. It is important to note that this quota opens a competitive environment for this kind of project during bids, which promotes the diversification of the national energy matrix and energy efficiency.

Contracts for distributed generation

Distributed generation that is procured in the long term bid can get one of three kinds of contracts:

- **A contract for the difference in the load curve**: here the generator sells a block of capacity to the distributor whose price stays constant through the life of the contract, with the commitment of an energy curve to supply a certain energy demand.
- **An energy lease**: in this kind of contract the generator sells a block of capacity to the distributor with a price that stays constant through the life of the contract and a certain quantity of energy with a price that is calculated during the purchase. For example, if the price of energy in the contract is less than its price in the market, the quantity of energy committed in the contract is assigned. If this is not the case, there is no energy assigned.
- **A contract of generated energy**: the generator agrees to sell all the energy it can generate to the distributor.

Spain: impact of distributed renewable generation on the operation by distribution and transmission companies

Regulation in Spain establishes that distributed generators in a special regime can choose one of these options of reimbursement:

- Inject energy to the system through a transmission or distribution network pursuant to a single regulated tariff.
- Sell energy to the wholesale electric energy market at the market price plus a subsidy.

The distribution companies in Spain do not currently purchase or commercialise energy, so they focus their effort on maintaining, developing and operating their distribution grid.

The complexities associated with the operation of this kind of distributed energy, in many cases from renewable resources, drives a demand to establish requirements and incentives that promote ancillary services and enhancements in the quality of the energy produced by these installations. These requirements or incentives (in addition to the above mentioned reimbursement relative to reactive energy and obligation to support voltage loss) include the following:

- The obligation to supply operation plans and to adhere to them for every installation. The rules provide that, where there are differences between the planned and actual

[100] Generation technologies of renewable energy, except hydraulic and biomass.

production, penalties may be imposed for every installation with a capacity higher than 15 kW.

- The mandatory connection of the generation installations to control centres connected with the operator of the system, which can be operated in real time. This obligation is established for generators with an installed capacity of above 10 MW or for installations that are part of a group of installations with a total capacity of 1 MW.
- The obligation to send telemetry to the operator of the system in real time. This obligation is established for generators with an installed capacity of above 1 MW or for installations that are part of a group of installations with a total capacity of 1 MW.

These measures, established in the Royal Decree 661/2007 and expanded in Royal Decree 1565/2010, are mandatory and have been applied so as to suspend the economic incentives to installations that do not meet the requirements.

In summary, these regulatory adjustments increase the safety of the operation of the transmission and distribution grids, and allow the integration of a higher amount of this kind of energy.

Ancillary services

Ancillary services are those associated with generation, transmission and distribution that are necessary to guarantee safety and quality in the supply of electric energy. The most common ancillary services are:

- Frequency control – active power
- Voltage control – reactive power
- Black start and islanding operation

The following sections discuss each of them as related to distributed generation.

Frequency regulation

Due to the notable growth that distributed generation is currently experiencing, there are more frequently instances that illustrate its impact on the operation of electric systems.

In countries like **Spain**, where distributed generation now represents a significant proportion of conventional generation, this ancillary service is contributing to the stability of the electricity system, which is also reinforced and protected by the measures that have been discussed previously.

In **Guatemala**, the procedure for frequency control is regulated as an obligation of the generators, considering distributed generation.

However due to its small size (a capacity of less than or equal to 5 MW) in relation to the total capacity of the system, its contribution to the Primary Frequency Regulation (PFR) can be of little significance, since PFR in **Guatemala** is located in a band of +/-3% of the capacity of the generator. For the case of distributed generation, this is equal to a capacity of

+/- 150kW, which is a small margin compared to the economic impact of the purchase of frequency control equipment for this kind of projects.

Voltage regulation

Current regulation in **Spain** provides for an incentive for the generator when it is producing energy in a range of power factor very close to 1, and a penalty if they do not observe the power factor range between 0.98 capacitive and 0.98 inductive. This provision is seen to contribute to the safety of the system.

In addition producers above certain installed capacity are required to adhere to reactive energy policies dictated by the system operator in real time. An example of this could be a signal sent by the system operator to absorb reactive energy during valley hours. Failure to respond to signals leads to the corresponding penalties. Incentives are available for adherence to such direction from the system operator.

Generators who opt to sell their energy in the market have the possibility of participating in the procedure of voltage regulation in the transmission network,[101] provided they meet the mandated technical requirements.

Black start and islanding operation

One of the fundamental ancillary services is black start and the formation of islands. These services are regulated by operative and commercial procedures.[102]

Due to its technical characteristics, black start is the capacity of a generator to start and connect to the grid without a voltage reference in its terminals and without the need for external energy sources.

Although it is technically possible, it is currently very difficult for distributed generators to participate in the black start ancillary service for three main reasons:

- Systems with a large quantity of wind power generation (as in the Spanish system) are vulnerable in situations of black start because of the variations in energy production which may cause instability in the islanding systems.
- There must be an adequate coordination between the system operator, the dispatch of distributed generation, and the demand from the distributors.[103]
- There are no established operative procedures that allow the implementation of this ancillary service in distribution.

Islanding operation could present important synergies in the enhancement of the reliability rates in the distribution grids, although their development has yet to resolve the following:

[101] P.O.7.4: Ancillary service of voltage regulation in the transmission network.

[102] Operative Coordination Standard No. 3 and Commercial Coordination Standard No. 8 of the Wholesale Market Administrator.

[103] The operator of the distribution system has a transcendental role, as discussed in section 4.1.

- Improve the mechanisms to control and monitor generators;
- Install more elements of voltage regulation; and
- Create regulatory mechanisms to develop and encourage the operative procedures for islanding operation in distribution systems as an ancillary service of generators, guaranteeing the correct assignment of costs with transparency in their calculation.

Finally, it is important to note that in most of the distribution systems there is not as much installed generation as connected demand, which imposes a strong technical restriction on regulatory mechanisms that encourage the use of islanding operation. This restriction can only be overcome if that islanding operation is formed by matching a lower connected demand with the capacity of distributed generation.

Access to information that should be available to Distributed Renewable Generators or potential investors in Guatemala

As mentioned previously, the exploitation of distributed generation displaces the use of generation coming from non-renewable resources, especially fossil fuels. Since distributed generation projects have a capacity of less than or equal to 5 MW, they have lower technical requirements than those required by renewable generation projects of larger capacity.

Since the Distributed Renewable Generation Technical Standard was approved by the National Commission of Electric Energy in September 2008, ten hydroelectric projects have been granted access to the distribution grids. Their installed capacity is 12 MW.

The Asociación Nacional del Café (National Association of Coffee Producers) estimates that their members have hydroelectric projects with a capacity of 500 MW. These projects are usually operating in isolated systems to satisfy the demand of the coffee producers. This example clearly illustrates that resources for distributed generation exist and that there is a will to develop such projects.

The National Commission of Electric Energy conducted a study to ascertain the existing barriers impeding the development of renewable generation projects, especially small ones. The study found that an important barrier was access to information and that the regulation was difficult to understand.

These barriers impeded the development of distributed generation projects. Investors perceived that regulation was too complex and decided that it was not worth investing the time to find out how to connect, operate and commercialise such projects, even when they had the possibilities and resources to develop them.

Another perception was that current regulation did not allow generation with installed capacities of less than or equal to 5 MW to participate in the market, which was not true.

Considering these aspects, it is important to mention that most of the distributed generation projects are developed by people with little experience in regulatory environments. Given this audience, information has to be presented clearly in a non-technical way. This is a difficult task, because documents have to be easy to comprehend, but at the same time have to include enough technical and legal information to provide sufficient clarity on the detail.

The information that should be available to potential investors in distributed generation in Guatemala includes the following topics:

- Regulatory framework related to distributed generation, including the General Electricity Law and its rules, and the Distributed Renewable Generation Standard.
- Market procedures that should answer the following questions:
    - What is the firm offer and efficient firm offer of a distributed generator? What is it for and how is it calculated?
    - Under what conditions should a distributed generator demonstrate its firm offer and efficient firm offer?
    - Who is responsible of the calculation of firm offer and efficient firm offer of a distributed generator?[104]
- Studies to identify the potential for the development of distributed generation projects.
- Distributed generation projects currently in commercial operation.

This information should be laid out in a simple and condensed way, so potential investors can understand it clearly.

Promotion of distributed renewable generation in Guatemala

Distributed generation in **Guatemala** is currently promoted through seminars related to the development of distributed renewable generation, as well as long term bids to cover capacity and energy demand for distribution companies.

Conclusions

The modernisation of the regulatory framework related to distributed generation in **Guatemala**[105] has promoted new investments in generation.

Owners of renewable generation plants, which operate in isolated systems, have found measurable incentives that allow them to connect to the grids.

Under this new regulation, distributed generators can participate in open bids to supply the demand of distributors or to sell their energy in the Guatemalan spot market. Market transparency and clarity in the rules that define the options to buy or sell energy are fundamental for the evaluation of a distributed generation project. This helps to determine whether the project is economically viable or not.

Some of the benefits from the modernisation of the regulatory instruments are:

[104] As mentioned in section 5.1.1, the simplified procedure for the calculation of firm offer of distributed generation is currently being designed.

[105] Refer to the Distributed Renewable Generation Standard.

- Motivating investors to develop projects of distributed generation because it clarifies the related procedures for the connection, operation and commercialisation in this type of project;
- Promoting the provision of electric energy demand by using local natural resources, reducing the consumption of imported fossil fuels;
- Creating the economic and social conditions necessary for the development of rural areas in Guatemala by creating labour sources and a reliable energy supply;
- Contributing to changing the electric energy generation mix,[106] which currently largely comprises fossil fuels, with the associated reduction in greenhouse gas emissions; and
- Contributing to the reduction and stabilisation of the electric energy tariffs for the final users.

The experiences of **Guatemala** with the Distributed Renewable Generation Technical Standard reflect that when regulatory mechanisms are easy to understand, but also technically and legally consistent, the certainty and transparency provided encourages the development of new projects. This is demonstrated by the new investments since 2008.

In **Spain**, the connection and access of generation to the distribution and transmission grids is a right of the producers that is guaranteed by law and is regulated by a specific standard. This standard considers, among other factors, the restriction of such right only in the case of risk to the electricity supply and the solution of possible congestion in the grids in the short, medium or long term, which diminishes the uncertainty of the development of distributed generation projects.

The establishment of technical standards governing the procedures and minimal required equipment for connection to the grids, and the identification of mechanisms of expansion or modification of the grids by the generators, also reduces uncertainty.

Based on current regulations in **Guatemala**, distributors do not consider generation connected to the grid in their planning; this is not optimal. There is enough technical evidence to demonstrate that to achieve optimal performance in the grid distributors have to consider important aspects. These include: the location of generators in the grid, topology and structure of the grid, quantity and dispersion of generation as well as their demand and generation profiles. However, there are currently no regulatory mechanisms to incentivise distributors to adopt this approach to planning.

Although the consideration of distributed generation as an alternative to planned investments in the distribution grids can result in synergies that facilitate operative efficiency, in Guatemala this alternative would not be consistent with the regulation at the time of the economic evaluation of installations through VAD. This is because the regulation is

[106] The Guatemalan energy policy establishes a goal of reducing 35% of electric energy consumption generated using fossil fuels by 2022, down from 65%.

predicated on a concept of grid efficiency which does not include distributed generation. Thus, the following questions should be considered:

- Should users have to pay for the installations that will be used to connect a generator to the distribution grids?
- Are there mechanisms that can be used to transparently quantify the benefits that come from distributed generation to the operation and exploitation of the grids?
- Can those added benefits be assigned to each user?

The difficulty of operating this kind of installation in **Spain** has forced the establishment of requirements and incentives that promote the benefits of ancillary services and enhancements in the quality of the produced energy to facilitate its integration to the system. These requirements or incentives are, among others: those related to reactive energy; the obligation to support voltage loss; the obligation to supply operation plans the requirement to connect to control centres; and the obligation to send telemetry to the operator of the system in real time.

Recommendations

The current regulatory scheme does not consider distributed generation as an alternative for investments in the grid. A market mechanism could be designed to promote the presence of this kind of generation in the critical hours of operation, such as in the cases of maximum zonal demand or in the case of contingencies. In addition, the payment of a capacity guarantee could be viewed as an incentive for the availability of the plant and also penalise it in case of unavailability. Another alternative could be the creation of a technical restriction market. A distributor who is enabled to act as operator of the distribution system could be responsible for the management of such a market.

In **Guatemala**, regulation has proved to be effective in the promotion of projects of distributed renewable generation.

However, it is important to modify the operative procedures to calculate firm offer and efficient firm offer, and the management of diversions for distributed generation. Such operative procedures should be easy to understand and should be presented in a non-technical way, without losing consistency in their application in the market.

As a mechanism to promote distributed generation, it is possible to perform studies that identify the potential for the development of this kind of project. Such studies could also be used as a technical base for the bids that are dedicated to distributed generation. Generators that win such bids could get a contract that can be used to support their investment to build the project. This economic financial scheme would promote distributed generation, with the corresponding benefits for the distribution company.

Finally, considering the experience in **Guatemala** in relation to frequency regulation, the impact of renewable distributed generation over PFR is small, but the economic impact of the purchase of frequency regulation equipment can be considerable. It is recommended that the operative procedures related to PFR exclude this kind of generation from the obligation to provide this ancillary service. These procedures should be in harmony with the current regulatory framework.

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6. Challenges in developing countries

6.1 Introduction

This chapter looks at the challenges faced by developing countries. Some of them have high potential RES, and distributed generation is of particular use across large geographical areas with a fragmented population, but lack: appropriate levels of funding, clear institutional regulatory frameworks, and adequate technical and management skills. Large countries like China, India and Brazil face different, but equally harsh challenges on their way to integrate RES in their energy portfolios. These challenges are more to do with the size of their economies and their energy habits developed up to now.

The following paragraphs provide context to the challenges faced by African countries. Detailed information on other countries are provided in the case studies' section.

The economic and energy context of African countries

Energy is an essential factor for the socio-economic development of populations and the current situation in developing countries varies widely from one country to another. Concerning Africa, some countries have significant potential in fossil energy (e.g. Algeria, Gabon, Nigeria and South Africa) while others have abundant renewable energy resources (e.g. hydro in the Great Lakes countries, wind in Morocco etc.). In addition, there is significant solar energy potential across Africa. Nonetheless, a number of African countries remain dependent on traditional energy sources such as wood.

Consumption per capita varies greatly from one country to another. Access to commercial energy is very limited in many countries because of the relatively low purchasing power and the lack of access to well developed and/or maintained energy infrastructure. In fact, a significant portion of people in developing African countries currently do not have access to electricity due to a lack of independent electricity sources or non-existent connection to a distribution network. Largely, these people live in rural areas. As the needs of these populations are small and they are spread over large areas, renewable energy could address these problems.

The existing environmental and economic problems, namely: pollution, high cost of fossil fuels (oil and gas in particular) in relation to the purchasing power of local people, and the deforestation due to the use of wood as a fuel, has encouraged a growing number of African countries to promote renewable energy. The impact on the environment, particularly in terms of emissions of greenhouse gases and depletion of forest resources in these countries, necessitates a shift towards a clean and environmentally friendly renewable energy.

As noted previously, many developing countries have very high solar electricity potential. The current obstacles to the promotion of solar energy are mainly high equipment costs and lack of subsidies to encourage the investment. However, the importance of solar energy for developing African countries should be underlined. For instance, the use of solar panels could avoid the need for investment to increase electricity production especially during peak hours. Furthermore, PV systems offer a good solution for remote areas as this technology is ideally suited for small scale applications (refrigeration, lighting, pumping water, powering communications systems etc.).

In addition, some developing countries have a large pool of biomass not yet exploited. This usually comes in the form of forest undergrowth, timber size in arboriculture and viticulture products of agro industry, by-products of sugar, etc. The benefits of biomass include its contribution to tackling global warming (low greenhouse gas emission) and promotion of renewable energy and energy efficiency, while supporting public policies affecting employment, land use and agriculture. As a source of renewable energy, biomass is likely to provide viable solutions to: energy problems, pollution and deforestation, in a number of developing countries.

Current difficulties in the development of renewable energy

Financing renewable energy generation is nevertheless a major challenge for developing countries. Despite the decrease in the cost of renewable energy in recent years, obtaining funding remains a major obstacle for many countries, especially since renewable technologies require massive investment in both human resources and physical assets. The main difficulties renewable energy development has encountered in developing countries so far include:

- The lack of an appropriate (adequate) institutional and regulatory framework to encourage investment in capital intensive development of renewable energy. In a number of countries there are no state subsidies to encourage the development of renewable generation;
- Limited access to conventional commercial energy due to the low purchasing power of developing countries. Consequently, this necessitates the use of support mechanisms (subsidies) for energy prices by governments;
- The small number, if any in some cases, of companies specialising in renewable energy (installation and management of technical equipment);
- Local industries manufacturing equipment and/or materials used are not suited to the generation of renewable energy; and
- The lack of technical and management skills to produce renewable energy.

Steps forward

Developing countries, especially in Africa, need to find new ways to finance infrastructure to support production of renewable energy. It will be necessary to develop appropriate solutions to offset the risks encountered in order to promote investment for development of renewable energy.

Currently, very few African countries are able to offer programs which aim to subsidise the production of renewable electricity and to guarantee high purchase prices for it. Moreover, in several countries in sub-Saharan Africa, the electricity markets are poorly developed. Difficulties of various natures - political, institutional, regulatory, financial and technical - means investment risk is very high in Africa and, despite some progress and reforms, electricity markets still do not function properly.

The inadequacy or lack of clear regulations, local funding and a reliable electricity infrastructure all increase the risk of developing renewable energy generation plants. The deficiency of the above mentioned conditions, especially in sub-Saharan Africa, substantially reduces the attractiveness of the area to private investors. Hence, African countries need support programs for renewable energy in order to mitigate the obstacles and attract more investment.

As renewable energy can fuel economic growth for developing countries whilst preserving the environment, it should be seen as a part of development priority. However, as it often costs more than generation from conventional energy sources, developing countries should establish long term energy policies and appropriate institutional and regulatory frameworks to promote development of renewable energy.

6.2: Case study 11: Algeria

In Algeria the development of RES is managed under the following legislative and regulatory framework:

- Law N° 02-01 for electricity and gas distribution, promulgated on 5 February 2002, provides the following incentives and regulatory tools:
  - A premium mechanism based on a bidding process to select the power generation projects on the base of the lower kWh prices (Article 26);
  - Premiums are integrated in final tariffs and called Diversification costs of the generated electricity for the selected RES and cogeneration plants (Article 95);
  - Access to the transportation and distribution networks is granted and free on charge;
  - Distributors have the obligation to buy all the electricity generated by the RES producer.
- Law N° 04-09 for the promotion of RES under the framework of Sustainable Development, provides the certification of origin for the eligible candidates to the premiums.
- Decree N° 04-92 relative to the diversification costs of the generated electricity, published on 26 February 2004, regulates all these provisions as a secondary legislation.
- The Regulatory Commission for Electricity and Gas (CREG) is committed by law N° 02-01 to manage the development of the electricity generation from RES and cogeneration. Notably, in this way, CREG has to define and publish a decennial

indicative development program for RES and cogeneration plants and manage the bidding process.

Algeria also has a national fund dedicated to financing support of the RES, supplied by a tax from hydrocarbon royalties (0.5%).

The government set a national renewable energy target of about 8% by 2020 and 40% by 2030. These targets take into account both these targets at a national level and the opportunities for green electricity exports, particularly to the EU.

This ambitious program will be implemented mainly through the deployment of solar concentrating solar power (CSP), solar photovoltaic and wind.

6.3: Case study 12: Malawi

The renewable energy industry in Malawi is broadly speaking in its infancy phase but is steadily developing. Recently there has been a sharp rise in demand for renewable energy as an alternative source to conventional electricity. The renewable energy mix is currently dominated by solar PV/thermal and wind energy stand-alone systems. The government plans to explore other forms of renewable energy resources such as geothermal following evidence of potential for the resource through manifestations of hot springs spread across the country. The latest development in this direction in Malawi is the joining of the East African Rift System (EARS) group. The African Union Commission for the development of geothermal energy is championing the development of the resource.

Challenges

A significant challenge facing the renewable energy industry in Malawi is lack of renewable energy act, regulations and strategies. This has negatively impacted the industry and resulted in creating the following regulatory challenges and constraints:

1. Economic challenges:

- high upfront cost of renewable energy technologies, a large proportion of which arises from import duties and surtaxes;
- lack of dedicated, affordable and sustainable financing mechanisms;
- financiers lacking awareness of the efficacy of renewable energy technologies to justify establishment of dedicated financing mechanisms;
- lack of business skills by renewable energy technologies companies to develop bankable business plans;
- difficulty for end users in obtaining loans for renewable energy technologies.

2. Institutional and governance challenges:

- lack of a deliberate policy and strategy on renewable energy technologies;
- lack of standards, code of practice and compliance protocols;
- lack of legal and regulatory frameworks;

- limited service delivery modes;
- small number of trained companies to offer supply, installation and maintenance services for renewable energy technologies;
- lack of information about the efficacy of renewable energy technologies among policy makers, NGOs and the general consumer public.

3. Lack of equipment and expertise for the development and training of renewable energy technologies

Flowing out from the above is also lack of coordination among key stakeholders in renewable energy. These are stakeholders who are expected to provide information that foster renewable energy technology development and data base formulation. These include experts from meteorological and environment departments, research institutes and academia. For instance, currently Malawi does not have reliable and comprehensive data on wind mapping etc. This is a big drawback for developers in wind energy generation.

The way forward

The renewable energy industry in Malawi needs support in developing a clear regulatory framework for the sub sector. This framework will in turn lead to the development of viable renewable energy resources. There is a scope to draw on and benefit from the experiences of countries which have developed the renewable energy and have regulatory instruments already in place.

As a way forward, in 2008 the Malawi Government established the Malawi Energy Regulatory Authority (MERA) following the enactment of energy laws.

6.4: Case study 13: The People's Republic of China

Country profile

China possesses a sizeable electric power sector, and it continues to experience tremendous growth. China had total installed electricity generating capacity of 962 GW and net generation of 4,228 TWh at the end of 2010.[107] Yet, despite its already prodigious size, China continues to grow exponentially in both capacity and generation.

China's electric power comes from a variety of resources. Thermal generation makes up about 81% of power generation and over 77% of installed capacity, coal comprises the majority of this, with a small amount of natural gas making up the remainder.[108] Despite this large reliance on fossil fuel, a growing amount of China's electricity is generated from renewable resources, principally hydro and wind. China produced 686 TWh of electricity

[107] State Energy Regulatory Commission, 2010. Original report is in Chinese. Translation provided by Max Dupuy and Wang Juan, both of the Regulatory Assistance Project, Montpelier, VT.

[108] US Energy Information Administration, 2011

from hydroelectric sources in 2010, up 20% from 2009 levels.[109] China had installed wind energy capacity of 44.7 GW by the end of 2010.[110]

Overview of power sector

Historically, China provided electricity to the country via a governmental authority, which included vertically integrated generation, transmission, and distribution services. In the late 1990s, the governmental authority was converted into a corporation, the State Power Corporation. For the several years following this, the corporation's old 'governmental' functions, as opposed to its 'business' functions, were increasingly stripped away.

Since that time, the Chinese electric sector slowly has moved toward a system with more market based elements and with more independent generation, transmission, and distribution components.

In 2002, generation assets were broken off from State Power Corporation to form five independent, although still state owned, generating companies. Each was intended to control no more than 20% of the country's generating capacity.[111] Apart from these five companies, the remaining generation is provided by independent power producers, often in partnership with state owned entities.[112]

Also in 2002, the transmission and distribution functions were divided between two grid companies (gridcos): the State Grid Corporation and China Southern Power Grid Company (Southern Grid).[113] The transmission grid is divided into six regions: north, northwest, northeast, central, south, and east. State Grid controls approximately 80% of the transmission and distribution grids serving most of the country, and Southern Grid covers the remaining 20% across the southernmost five provinces.[114] Basic interconnection among the regional grids was achieved in 2005[115] but power flow among regions and even between provinces within regions is limited.[116]

Electricity is regulated by two principal agencies: the State Electric Regulatory Commission (SERC) and the National Development and Reform Commission (NDRC). NDRC maintains responsibility for pricing, investment, and power plant approvals. SERC maintains

[109] State Energy Regulatory Commission, 2010. China was the largest producer of hydroelectric power in the world in 2009. (US Energy Information Administration, 2011).

[110] Global Wind Energy Council, 2011

[111] Pittman & Zhang, 2008

[112] U.S. Energy Information Administration, 2011

[113] Pittman & Zhang, 2008. There is also a small independent grid operator for the western portion of inner Mongolia. (Cheung, 2011).

[114] Regulatory Assistance Project, 2008

[115] Zhou et al., 2009

[116] Kahrl, Williams, Ding, & Hu, 2011

responsibility for the design and oversight of generation markets and implementing power sector reforms.[117]

China's electricity market is a single buyer purchasing agency model whereby the provincial and municipal subsidiaries of the two large gridcos buy power from generators and sell to customers or local distribution companies.[118] Wholesale and retail electricity prices are determined and capped by NDRC, although there have been some small experiments with free market pricing.[119]

The wholesale prices theoretically offer a 12% to 15% return to generators, but this price inflexibility often creates pressure on generators' margins when fuel costs rise.[120]

Transmission and distribution are not priced separately but are embedded into the price of retail rates.[121]

China has a strong commitment to renewable energy development, as shown by the 2006 Renewable Energy Law which provides economic incentives for renewable energy production. The law requires grid companies to purchase all the electricity renewable generators produce, and creates a renewable energy fund to support research and development. [122]

This commitment also appears in both the 11th and 12th Five Year Plans. In 2007, China initiated a five province pilot energy saving dispatch program that requires renewable resources be dispatched first as a priority.[123] While the pilot has resulted in the dispatch of more renewables, technical and economic obstacles have prevented the rule from being applied universally.[124] Finally, in 2009, China introduced a feed-in tariff for wind power generation with four different categories depending on the region's wind resources.[125] Despite these strong commitments, several barriers remain to integrating renewables into China's electricity system.

Barriers to integration of renewables

Most jurisdictions trying to integrate large amounts of renewable resources into their power systems struggle with the variable nature of renewable power (Chandler, 2008). China is no

[117] Regulatory Assistance Project, 2008

[118] Regulatory Assistance Project, 2008

[119] Tawney, Bell, & Ziegler, 2011

[120] Tawney, Bell, & Ziegler, 2011. Coal prices are not fixed as are end-user electricity prices, thereby opening the potential that increasing coal costs could "eat into" the 12-15% return to generators.

[121] Regulatory Assistance Project, 2008

[122] Tawney, Bell, & Ziegler, 2011

[123] Regulatory Assistance Project, 2008

[124] Ciwei & Yang, 2010; Gao & Li, 2010; Cheung, 2011

[125] Global Wind Energy Council, 2011

different. But, "[if] a power system is sufficiently flexible, in terms of power production, load management, interconnection and storage, the importance of the variability aspect is reduced" (Chandler, 2008). The remainder of this case study examines China's struggles to achieve power system flexibility.

1. Flexible generation: The variable nature and low capacity factor of renewables requires more ancillary services to manage the supply fluctuations.[126] One means of providing these services is to create a generation fleet nimble enough to respond quickly to variations caused by renewable resources.[127] China faces barriers, some unique, that impede the easy use of flexible power production to address renewables' variability.

In many regions, China's load shape, because of the country's high industrial usage, is relatively flat compared to countries with more residential and commercial electricity consumption. Consequently, China's electric system has historically needed less load-following and peaking generation, the very kinds of resources that would help respond to renewables' variability.[128]

China's existing fleet is comprised largely of coal-fired generation. These are particularly unsuited to quick response times as it takes a long time to ramp up and ramp down coal plants. Many of the smaller coal plants that may have been used for balancing renewables have been taken out of service in favour of larger, more efficient plants.[129]

China's hydro generation faces challenges undermining its usefulness as a balancing option, such as limited spare hydro capacity.

The fact that there is insufficient transmission connecting geographically distant wind and hydro resources makes it challenging to use the respective resources to balance one another. Additionally, China employs combined heat and power plants that provide district heating in the winter and simultaneously generate electricity. Since these plants do not have bypass technology allowing them to generate heat without generating electricity, they cannot be readily cycled as a balance for variability.[130] Each of these impediments undermines China's ability to use power production as a balancing option.

2. Flexible load: A second way to smooth variable renewable energy is to manage loads on the electric system. Overall load could be increased quickly to absorb excess renewable generation or curtailed to balance drops in renewable generation. Employing demand response programs and technology is one effective way China can manage load, and it is beginning to take important steps in this direction. China enacted a national demand side management rule that took effect on 1 January 2011. The rule puts an efficiency first

[126] Chandler, 2008; Cheung, 2011

[127] Chandler, 2008

[128] Kahrl, Williams, Ding, & Hu, 2011

[129] Cheung, 2011; Schultz, 2011

[130] Tawney, Bell, & Ziegler, 2011

mandate on utilities and requires them to achieve energy savings of at least 0.3% in sales volumes and 0.3% in maximum load compared with the previous year.[131] "It also lays the foundation for the expansion of demand response programs by requiring load monitoring equipment to be installed on 70% of peak load and load control equipment on 10% of peak load in any locality" (footnote omitted) (Schultz, 2011).

3. Interconnection: Another way to integrate variable resources is to maintain a widely interconnected electric grid incorporating diverse generation resources and located over a wide geographic area.[132] Ample grid and transmission interconnectivity ensures remote renewables can actually get to load and variability can be balanced. China's grid currently is not providing this kind of interconnectivity or balancing capacity.

One of China's foremost problems stems from the physical realities of China. The country is geographically vast; each of its six regional grid areas are the size of most countries. Moreover, much of China's rich renewable resources are in the north and west, while most of the energy demand is in the south and east. It is an expensive, time consuming, and technically challenging undertaking to build a system capable of transmitting large amounts of variable power from remote sources to distant load centres.[133] The distance problems are exacerbated because the timeline for developing a wind farm is short whereas the timeline for interconnecting to the grid is long. The difficulty in synchronising these timelines results in renewable projects remaining unconnected from the grid for extended periods - a year or longer.[134]

China's grid is still quite segmented. Interregional connections between the six grids are weak, and cross-regional trading in 2009 accounted for only 4% of the total electricity produced.[135] "The lack of greater interconnection among regional and sub-regional grids imposes constraints on optimal use and delivery of energy resources, limiting the availability of dispatch- able hydropower resources to provide peaking and ancillary services" (Kahrl, Williams, Ding, & Hu, 2011).

A lack of alignment between the various players in the industry and in government further fragments grid operations. The 2002 restructuring resulted in provincial level power companies owning significant amounts of generation with provincial grid company subsidiaries taking control of the day-to-day grid operations and short term planning. Yet, planning for larger scale projects and ratemaking is still controlled by central government agencies, such as NDRC.

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[131] Schultz, 2011

[132] Chandler, 2008

[133] Tawney, Bell, & Ziegler, 2011; Kahrl, Williams, Ding, & Hu, 2011

[134] Energy Research Institute of the NDRC, 2010

[135] Cheung, 2011

This joint structure has led to the development of parallel policy agendas, poor planning and coordination, and difficulties in performing efficient electricity planning, dispatch, and pricing.[136] Furthermore, although the grid companies are jointly responsible for the management of power transmission and distribution systems, there is little incentive for intercompany cooperation, particularly in devising solutions to inter grid power flow and trading.[137] Finally, there is a lack of collaboration between developers and grid operators, resulting in projects not being connected to the grid in a timely manner following commissioning.[138] The fiscal system in China focuses on revenue collection at the generation level. This incentivises provinces, municipalities, and other government entities to favour construction of generation units within their administrative boundaries to maximise their fiscal revenues.[139] These kinds of policies undermine the development of interconnections, inter provincial trading, and lead to the inefficient use of resources.

China also lacks nationwide technology standards for grid interconnection with renewable generators.[140] The lack of standards makes interconnection difficult and results in Chinese wind farms having lower capacity factors.[141] In 2005, the Chinese government issued Technical Regulations on Connecting Wind Power to Power Grids, but the regulations were not laws and expired in 2008.[142] The lack of standards has pitted developers and grid operators against one another. For example, the grid companies would like to require turbines to contain low voltage ride-through technology. The rationale being that this will ensure they handle drops in voltage in a predictable way, rather than risking shocks to the larger transmission network.[143]

Renewable developers contend that the grid operators are using this kind of argument simply to prevent renewable projects from connecting to the grid.[144] Others are concerned that the technology and patent for low voltage traversing ability belongs to foreign companies and will make Chinese companies more dependent on foreign technologies.[145]

4. Cross provincial contracting: Establishing and nurturing wide markets that support energy trading across regions is an excellent way to manage variability.[146] China's current

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136 Kahrl, Williams, Ding, & Hu, 2011; Tawney, Bell, & Ziegler, 2011

137 Cheung, 2011

138 Peng & Berrah, 2010

139 Peng & Berrah, 2010

140 Tawney, Bell, & Ziegler, 2011

141 Peng & Berrah, 2010

142 Weixun, 2010

143 Tawney, Bell, & Ziegler, 2011

144 Tawney, Bell, & Ziegler, 2011

145 Weixun, 2010

146 Chandler, 2008

system does not encourage cross grid trading. There are two types of prices: prices under which each power plant sells its output to the grid company, and prices under which the grid company sells its electricity to the consumers.

Despite recent incremental changes to wholesale generation and retail rates, China continues to lack a formal, transparent mechanism for linking costs and retail prices in its electricity sector.[147] Since competitive generation markets do not yet exist, generation prices are still set administratively by the pricing bureau of the NDRC.[148] The focus of the system is on revenue collection at the generation level. As discussed in the previous section, restructuring resulted in provincial level companies owning significant amounts of generation, incentivising provinces, municipalities, and other government entities to favour construction of generation units within their administrative boundaries to maximise their fiscal revenues. This also means that local jurisdictions have an incentive to purchase electricity from their own generators rather than engage in interprovincial trade.[149] Most of the trade that does happen is governed by long term contracts, the terms of which are negotiated by the central government, provincial governments, and the grid companies.[150]

Furthermore, the market does not send proper signals to the renewable generators themselves. These generators are not required to pay for the transmission infrastructure necessary to carry their power to load centres. Instead this cost is borne by the grid companies, which are also required by the 2005 Renewable Energy Law to connect any renewable generation within their geographic region.[151] While the grid companies are partially reimbursed through a government subsidy based on the distance between the generation site and the main grid infrastructure, it is conceivable that the subsidy falls short of the actual cost of integrating the electricity.[152] The cumulative effect is that the system does not provide clear market signals or incentives to grid operators to engage in efficient cross grid energy trading. This prevents China from having an effective tool for mitigating variability.

[147] Kahrl, Williams, Ding, & Hu, 2011

[148] Regulatory Assistance Project, 2008

[149] Peng & Berrah, 2010

[150] Cheung, 2011

[151] Tawney, Bell, & Ziegler, 2011

[152] Tawney, Bell, & Ziegler, 2011

Paths forward

China is making admirable efforts to integrate renewables into its system, despite the many challenges it faces. Perhaps most importantly, China's central government has made a strong commitment to renewable energy, both in policy and in actual investment. For example, NDRC plans to increase wind capacity to 100 GW by 2020.[153]

China is investing heavily in its grid, specifically investing in several ultra-high voltage transmission corridors to strengthen its grid.[154] West to east electricity transfer projects are planned to build up the grid in three major transmission corridors, each with a transmission capacity of 20 GW by 2020.[155] This additional investment will improve grid interconnectivity and the ability to balance variable power. Also, China continues to push its new dispatch rule, which gives renewables preference in dispatch, and continues to seek ways to incorporate more market based measures to encourage inter grid trading and to instil market discipline into China's electric system. Each of these measures will help China to more fully integrate renewable resources into its electric system.

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[153] US Energy Information Administration, 2011

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6.5: Case study 14: The Republic of South Africa

Country overview

The South African power sector is by far the largest in Africa (Electricity Governance Initiative of South Africa, 2010). As of 2008, South Africa had installed electric capacity of 50 GW and had generated 240 TWh of electricity.[156] The vast majority of this power, 85%, is produced by coal-fired generation, understandably given South Africa's abundant coal resources.[157] Wind and hydro make up only a very small portion of South Africa's generation, with wind comprising only 3.2 MW of capacity and hydro[158] providing 3.4 GW of capacity.[159]

In the late 1980s, South Africa began a massive electrification process to provide electric service to rural and other off-grid communities. The process only took on real momentum with the demise of apartheid and the election of a post-apartheid government in 1994.[160] As a result of these efforts, the electrification rate has reached 75% nationwide but only 55% of rural populations have access to electricity; success has been greater in urban areas, where

[156] US Energy Information Administration, 2011

[157] Edkins, Marquard, & Winkler, 2010. South Africa's coal reserves account for 95% of African reserves and 4% of world reserves (US Energy Information Administration, 2011).

[158] Hydro, for these purposes, includes hydro, pumped storage, and hydro distribution.

[159] US Energy Information Administration, 2011

[160] Bekker, Eberhard, Gaunt, & Marqurd, 2008

rates are close to 88%.[161] The government's stated goal is to have universal access by 2012.[162]

Electricity demand is rising in South Africa, and that demand recently outstripped capacity. The problem resulted in rolling blackouts throughout the country during 2007. In January 2008, the Department of Minerals and Energy released a policy document on how to address the problem. The document, National Response to South Africa's Electricity Shortage,[163] laid out a plan for dealing with the short term blackouts. It proposed re-commissioning three coal-fired power plants and to increase long-run capacity, through building new coal and nuclear plants for example.

Renewable resources, energy efficiency, and demand side solutions have generally been given little consideration as means of dealing with South Africa's energy problems because of the country's rich fossil resources. There have been signs recently that this may be beginning to change.

Power sector overview

South Africa's power sector is fairly straightforward, as compared to the power sector in the EU, India, and the USA, all of which are in various stages of structural change and market reform. Eskom, the country's only utility, provides all of the transmission and distribution services, generates approximately 95% of the power used in South Africa, and approximately 45% of the power used in Africa.[164] The remaining 5% of power generation in South Africa is provided by independent power producers. While Eskom is a private company, it is wholly owned by the government of South Africa.

There are two principal governmental entities that deal with utility and energy policy in South Africa. The first is the National Energy Regulator of South Africa (NERSA), which was set up in 2004 to regulate the liquid fuels, gas, and electricity sectors.[165] NERSA is responsible for issues such as licensing of power plants, approving tariffs, and planning for infrastructure. The second is the Department of Energy (DOE), which is responsible for South Africa's energy policy, particularly for policies to drive universal access to electricity and for policies to diversify primary energy sources and reduce the country's dependence on coal.[166] In December 2009, an inter-ministerial committee on energy was set up to coordinate and

161 US Energy Information Administration, 2011

162 Bekker, Eberhard, Gaunt, & Marqurd, 2008

163 The plan may be retrieved from: http://www.info.gov.za/otherdocs/2008/nationalresponse_sa_electricity1.pdf.

164 Eskom, 2011

165 Never, 2011

166 Department of Energy, 2011

consult all crucial issues in the electricity sector, including being charged with formulating an integrated resource plan.[167]

Barriers to integrating renewables

South Africa's most pressing issue with integrating RES is the absence of a robust renewable energy sector. Quite simply, there has been a shortage of renewable project development. This is despite the fact that South Africa has large renewable resource potential. For example, some regions in South Africa are among the most suitable in the world for solar thermal energy.[168]

There are a series of impediments that seem to be obstructing the more robust development of renewable generation in South Africa. The remainder of this case study will examine those impediments and explore possible ways to overcome them.

1. History: South Africa's history of apartheid is a factor in the current scarcity of renewable energy. The apartheid system required South Africa to remain self-sufficient and independent from external energy supplies. This resulted in an emphasis on developing and relying upon the country's rich coal reserves. It also led to energy research and development which focused predominantly on fossil fuel technologies.

The two main energy providers, Eskom (electricity) and Sasol (fuel), do the majority of the investing in energy research and development, and they hire almost all of the university graduates in the relevant fields. These patterns have led to what most outside observers consider an inclination towards fossil fuel innovation rather than renewable resource development.[169]

2. The role of coal: Given the coal industry's predominant role in the history of the country and in the contemporary energy sector, it is not surprising that coal plays a role in frustrating a more robust development and deployment of renewable generation in South Africa. The coal industry is quite large and comprises a significant portion of South Africa's economy. The electric and synthetic fuel industries, both of which rely on coal, also comprise a significant part of the economy. With this role comes significant political influence for the respective coal based industries. The industries use their influence to protect the status quo and advocate policies that shape the energy markets toward their core competencies. Clearly this does not foster a favourable environment for renewable energy developers.[170]

Secondly, the competitive advantage of South Africa's economy is largely based on seemingly cheap coal and cheap electricity.[171] Questions of economic growth and global

[167] Never, 2011

[168] Never, 2011

[169] Pegels, 2009; Winkler & Marquand, 2009

[170] Pegels, 2009

[171] Never, 2011

competitiveness are intertwined with the ongoing dependence on coal-fired generation and a coal based economy. It is challenging to push for policies to diversify energy production and shift towards greater renewable generation given the central role coal historically played in relation to South Africa's economic security. A challenge for renewable developers is to push renewables from a development perspective.[172]

Thirdly, given how cheap and abundant coal is in South Africa, the comparative cost of renewable energy technologies is a significant barrier. Historically, South Africa has had some of the cheapest electricity prices in the world.[173] However, the apparent cost of electricity has risen sharply over the past few years, currently averaging ZAR .33 (US$0.046) per kWh.[174] Even at this price, however, the cost of wind development is not competitive with coal-fired generation.[175] Until renewable energy can be priced competitively with coal-fired generation, and/or the full environmental and health cost of coal is recognised in resource decisions, it will be difficult to develop renewable projects in South Africa.[176]

3. Unsuccessful government programs and coherent leadership: One of the most troubling problems facing the widespread integration of renewables in South Africa is that the government agencies charged with fostering the growth of renewables have been unsuccessful. While the country recognised the importance of renewables nearly a decade ago with the publication of the Renewable Energy White Paper, which set specific targets for renewable energy contributions to overall generation levels, the level of actual implementation has been quite slow. Less than 10% of the targeted new renewable energy capacity has been achieved to date.[177]

Officially, the DOE is responsible for energy related policy decisions, including those in relation to renewable energy. In practice, several other entities make decisions regarding energy sector policy, such as the governmental entities NERSA and the Department of Public Enterprise, and non-governmental entities, such as Eskom. Each of these entities has its own objectives and agenda. Aligning these different objectives and agendas is presenting a formidable challenge. There is a marked lack of communication and coordination both within and between agencies.

The lack of collaboration and coordination between departments parallels a lack of a focused policy.[178] Beyond a simple lack of coordination, "there is evidence of an historical adversarial and non-cooperative relationship between elements of the executive and other government

[172] Never, 2011

[173] Winkler & Marquand, 2009

[174] NERSA, 2011

[175] Pegels, 2009

[176] Arguably, the price of South African coal does not include the full environmental and health related costs it should were all of these real costs internalised into the market price of coal.

[177] Trollip & Marquard, 2010

[178] Never, 2011

agencies in the energy sector that need to cooperate for policy formulation and implementation to be effective" (Electricity Governance Initiative of South Africa, 2010).[179] Even for government insiders, it is not always clear from which body a particular policy originates. In the leadership vacuum, Eskom has taken it upon itself to make strategic decisions about investment in supply side assets.[180] All of this results in a weak renewable energy sector.

Two recent examples - the Renewable Energy Feed-In Tariff (REFIT) scheme and integrated resource plan (IRP) process – illustrate how misaligned government policy can undermine the development of renewables.[181]

In response to the electricity shortages of 2007 and 2008, NERSA engaged in a consultation process resulting in the REFIT guidelines being officially published in March 2009.[182]

A REFIT is a mechanism to promote the deployment of renewable energy that places an obligation on specific entities to purchase the output from qualifying renewable energy generators at pre-determined prices.[183] Through 2009 and 2010, NERSA reviewed and revised the REFIT in a series of consultations. However, the process quickly became unworkable. On 30 January 2010, after NERSA had just published a REFIT consultation paper, the DOE published conflicting draft regulations establishing a bidding system for the procurement of new generation, an approach contradictory to the REFIT. DOE's procurement process invites bids from independent power producers, including renewable energy generators, for specified quantities of new generation and makes no mention of the REFIT process.[184]

While the REFIT process has been progressing, the DOE has been working on developing and implementing an IRP in a totally different process from the REFIT. IRPs are public planning processes during which the costs and benefits of both demand and supply side resources are evaluated to develop the least-total-cost mix of utility resource options.

After struggling through initial planning, DOE realised it needed a more deliberative approach. An interim five year IRP1 was enacted and an inter-ministerial committee on energy was formed to work through the challenges and form a 20-year IRP2. A Draft IRP2 was issued in October 2010, but it was controversial and unsatisfactory to many of the

[179] For example, it is fair to argue that lack of cooperation among DOE, NERSA, and Eskom regarding policies associated with bulk generation and the role of independent power producers was a chief cause of the 2008 power supply crisis (Electricity Governance Initiative of South Africa, 2010).

[180] Electricity Governance Initiative of South Africa, 2010

[181] REFIT and IRP are merely two examples. There are a variety of other energy sector policy processes taking place that illustrate the governmental problems but which fall beyond the scope of this summary.

[182] Edkins, Marquard, & Winkler, 2010

[183] NERSA, 2009

[184] Trollip & Marquard, 2010

constituent stakeholders.[185] Both of these examples illustrate how misaligned government agencies and policies can frustrate the development and integration of renewables into South Africa's electric system.

Paths forward

While South Africa struggles to implement policies to encourage the development and integration of renewables, at least the country is attempting to address the issue, no matter how modest the results. Those that follow energy policy in South Africa indicate that the country can take two fundamental steps to address its inability to more successfully integrate renewables into its energy system.

First, South Africa could harmonise regulations governing the energy sector to a greater extent, as well as clearly delineating or rationalising the responsibilities of each stakeholder. DOE, the Inter-Ministerial Committee on Energy, and NERSA should act in a more coordinated manner to ensure a coherent regulatory structure oriented toward the same end goal is established. This should include clear targets for the different renewable resources, each of which has its own different characteristics.[186]

Second, South Africa can compensate for institutions and rules that tend to favour historical interests and security imperatives, and readjust current economic objectives that centre on the immediate or apparent costs and favour fossil fuels, particularly coal. Among the immediate steps to be considered, South Africa could encourage greater reliance on generation from independent power sources by establishing a neutral transmission system operator and power exchange that can more independently plan, initiate, and operate electricity transmission and generation.[187]

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[185] Pienaar & Nakhooda, 2010

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6.6: Case study 15: Brazil

Country overview

Brazil ranks among the largest power consuming countries in the world. Total primary energy consumption in Brazil has increased by close to a third in the last decade. This growth in consumption is being fuelled by Brazil's strong economic growth since the economic reforms of the 1990s.[188] In addition to economic growth, Brazil also has been engaged in a US$2.5 bn initiative, Electricity for All, aimed at bringing electricity to 90% of rural areas by 2008, primarily by linking them to the national grid.[189] This initiative is still ongoing.

The Brazilian power sector is the largest in South America and is the third largest in the western hemisphere, behind the USA and Canada, with a total installed capacity of over 107 GW.[190] The defining characteristic of the Brazilian power sector is hydropower which accounts for almost 80% of the country's electric capacity; the remaining 20% is comprised of nuclear and thermal generation (mostly natural gas-fired generation), and other renewable resources.[191]

Brazil has the largest water storage capacity of any country in the world, enabling its high dependence on hydropower. However, this same characteristic exposes Brazil to unique risks. Droughts, such as the one that occurred in 2001, can expose Brazil to power shortages when there is insufficient water flow to operate hydro generators. The 2001

[188] US Energy Information Administration, 2011; World Bank, 2011

[189] PSI Media, Inc., 2009

[190] Pew Environment Group, 2011

[191] PSI Media, Inc., 2009

droughts, coupled with an economic recovery that took place at the same time, resulted in extensive power shortages in many parts of the country late in that year. The government was required to ration electricity as a result of the drought and energy supply shortages. Situations such as these have given the government reasons to seek to diversity the generation portfolio.

Power sector overview

Traditionally, the Brazilian electricity sector was comprised of vertically integrated companies. These companies were government owned, with the distribution function being concentrated in state companies and the generation and transmission activities being mainly performed by federal and states companies.[192]

The situation began to change in 1993, when the government started a rigorous restructuring and privatisation of its electric sector. As a result of these efforts, vertically integrated companies were broken up. Most of the distribution services were privatised, and some but not all, of the generation services were also privatised.

In 1996, the Restructuring Project of the Brazilian Electric Sector (RESEB) was initiated under the Ministry of Mines and Energy. The RESEB increased the level of competition in generation and retail sales and contributed to a more transparent regulation of transmission and distribution activities. For instance, the Agencia Nacional de Energia Elétrica (ANEEL) was created as an independent, national electricity regulator.[193] "ANEEL's mission is to provide favourable conditions for the electric power market to develop a balance between the agents and the benefit of society" (Brazilian Electricity Regulatory Agency, 2011).

In 1998, the government began planning for a wholesale energy market. This started operating in 2000 but suffered from a series of problems, such as disagreements between generators and distribution companies over the proper price of certain energy. These problems were exacerbated by the energy shortages resulting from droughts in 2001 and 2002, which negatively impacted hydro generation. A second phase of restructuring began with the creation of the Chamber of Management of the Electricity Crisis (GCE) to deal with this energy crisis, particularly the short term supply problems.[194]

In 2004, the Brazilian government implemented yet another modification to the industry with the introduction of a new power sector model. This established a hybrid approach to state involvement that saw the sector split into regulated and unregulated markets for different producers and consumers. This resulted in considerable change to ownership and management of the sector. Today, around 65% of electricity distribution companies are

[192] Melo, Neves, da Costa, & Correia, 2007

[193] Melo, Neves, da Costa, & Correia, 2007

[194] Melo, Neves, da Costa, & Correia, 2007

privatised. Nevertheless, the majority of Brazil's major generation assets remain under government control, as well as almost the entire electricity transmission network.[195]

Integration of renewables

Thermal plants comprise only a small share of electricity supply in Brazil. The largest thermal contributor is produced by ethanol plants burning waste from sugar cane feedstock. There is some potential to increase generation from this resource.

More traditional thermal resources, fuelled by oil and natural gas, have a more limited role in the generation mix in Brazil. The fact renewable resources already play such a large role in Brazil's energy mix means their renewable challenges are quite unique.

Hydroelectric power dominates the power sector in Brazil. There are 24 dams with a capacity greater than 100 MW. The largest dam, Itaipu Dam, is 14 GW in size. This plant alone supplies about 25% of the power fed into the Brazilian grid annually.

Even though Brazilian planners aspire to diversify their portfolio away from hydropower, new hydro projects continue to be proposed for development. The largest of these developments, the Belo Monte plant in the Amazon basin, will be the third largest hydroelectric plant in the world.[196]

As mentioned previously, this reliance on hydropower exposes Brazil to certain unique risks. For example, as illustrated in 2001 and 2002, drought poses serious risks to the grid's reliability. Brazil recognises this threat and is seeking to diversify its portfolio to mitigate the impact of drought on their electric supply. A second problem with Brazil's reliance on hydro is a geographical one. Many of Brazil's hydro generators are located deep in the interior of the country where the water resources, particularly the Amazon River, are located. Brazil's energy demand tends to be more concentrated on the coasts. This requires the transport of power over vast distances, resulting in large line losses and exposing Brazil to potentially disastrous consequences should the transmission lines become overloaded or compromised.[197]

Wind energy is an excellent resource Brazil can use to complement its hydropower. Brazil's wind power potential may reach as high as 350 GW.[198] Brazil has both enormous land mass, large portions of which are uninhabited, and a windy 4,600 mile coastline; as such, the country is geographically well suited to wind development. Given this great potential, Brazil has high hopes for wind power. Wind is most plentiful in Brazil during the dry season, so it is an excellent complement to the seasonal rain cycles affecting hydro production. Additionally, because wind projects can and are expected to be widely spread throughout the country, wind can balance the geographical concentration of Brazil's existing hydro

[195] US Energy Information Administration, 2011

[196] US Energy Information Administration, 2011

[197] PSI Media, Inc., 2009

[198] Global Wind Energy Council, 2011

resources. Furthermore, when one the offshore potential of wind is considered, which will be geographically closer to Brazil's demand hotspots, wind energy becomes an even more attractive proposition.

Brazil recognised these challenges and responded to them with the passage of Law 10438 in April 2002, which created the Program of Incentives for Alternative Electricity Sources (Programa de Incentivo a Fontes Alternativas de Energia Elétrica, PROINFA). The purpose of PROINFA is to encourage the use of other renewable sources, such as wind power, biomass, and small hydroelectric power stations. Among other benefits, these smaller renewable projects can be located closer to the load centres, alleviating the need to build long transmission connections from the coast to the interior of the country. In encouraging the development of these other resources, Brazil may be able to complement its existing hydro resources with a variety of other renewables, thereby addressing some of the shortcomings associated with hydro.

PROINFA entails two parts. First, PROINFA establishes a program operated by Electrobras, Brazil's largest utility, whereby Electrobras will buy renewable energy from developers at set prices. Electrobras was required to enter into contracts with renewable generators that are valid for a period of 20 years. These contracts are only applicable to plants that began production before 2007 and must have been signed within 24 months of the publication of Law 10438. Second, under PROINFA, the Brazilian National Development Bank was charged with making special financing programs available for renewable developers eligible for PROINFA.[199] By employing this scheme, Brazil attempted to ensure financing was available for new renewable developments and to give some guarantee of future revenue streams for renewable projects.

PROINFA's first phase was completed in 2005. It created 3,300 MW of projects: 655 MW biomass, 1,266 MW solar, and 1,379 MW wind.[200] PROINFA wind projects account for over 95% of all wind power installations in Brazil with approximately 900 MW of capacity.[201]

Brazil also faces tremendous challenges in upgrading its transmission grid to meet the needs of integrating renewables. Since Brazil is so geographically large, the grid system was historically comprised of regional grids, which were almost totally independent of one another. In addition to the complications caused by the regional growth of the grid, the vast distances between the hydropower projects in the interior of the country to the load centres along the coasts pose further problems. Projects in the 1990s built up the grid and linked the north eastern and southern regional grids, but there is still need to expand.

Brazil's independent electrical system operator, Operador Nacional do Sistema Elétrico (ONS), is responsible for the technical coordination of electricity generation, dispatch, and transmission as well as overseeing the country's wholesale energy market. Part of this

[199] International Energy Agency, 2010

[200] World Resources Institute, 2011

[201] Global Wind Energy Council, 2011

responsibility includes handling the national grid and planning for grid upgrades. Brazil plans to invest almost US $2.2 bn in its transmission sector by the end of 2017. In 2009 alone, 12 auctions were held for the right to construct more than 2,400 km of transmission line, including the construction of nine substations (PSI Media, Inc., 2009). These investments will begin the process of building Brazil's grid in order to support the integration of its rich renewable resources.

Conclusion

As Brazil relies heavily on renewable resources, particularly hydropower, it has unique problems associated with integrating renewables on its system.

Its primary challenge is to diversify its supply and balance hydro's variability, without turning to fossil fuels. Given Brazil's abundant access to clean resources, it should be able to achieve its integration and balancing needs without recourse to carbon intensive alternatives.

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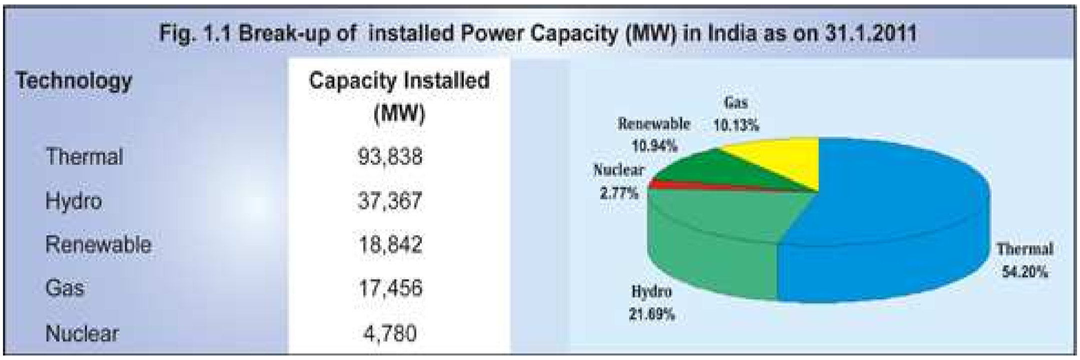
6.7: Case study 16: India

Indian Power Supply

While India's electricity is generated from a variety of sources, it relies disproportionately upon fossil fuel sources of energy because they are abundant and nominally cheap. India has geological coal reserves of 267 bn tons and proven reserves of 106 bn tons. The states of Jharkhand, Chhattisgarh, and Orissa together account for about 70% of the coal reserves found in India. Coal accounts for over 50% of the power generation in India.[202] The share of coal used for electricity generation in India is poised to grow in the coming years, with some estimates putting the share of coal in electricity generation as high as 70% by 2030. Nine power projects of 4,000 MW each have been identified for development through a competitive solicitation.

Figure 9: Installed power capacity in India



Source: Ministry of New and Renewable Energy, 2010

The total natural gas proven reserves in India as at 31 March 2010 stood at approximately 1,453 bn cubic meters, nearly double the reserves in 2004.[203] While crude oil discoveries in India may have stagnated, despite the increased exploration and production activities in the last few years, the natural gas sector has prospered. A number of notable natural gas discoveries have been made over the last few years, most of which have been made by private players who bid for exploration blocks under the Government of India's New Exploration Licensing Policy. Due to its superior environmental characteristics compared to coal or oil, natural gas is poised to take on an increasing role in the power sector in India.

Table 6: Natural gas reserves in India: 2005-10 (both onshore and offshore)

	Proven Natural Gas Reserves (BCM)

[202] PSI Media Inc., 2010

[203] Ministry of Statistics and Programme Implementation, 2011

	Proven Natural Gas Reserves (BCM)
2005	1101
2006	1075
2007	1055
2008	1050
2009	1074
2010	1437

Source: Ministry of Petroleum and Natural Gas, 2010

The abundance of natural gas and coal in India will make these resources an attractive option to meet India's future power generation needs. It will be a challenge for India's developers to establish and grow a renewable energy sector that can stand as a viable alternative to coal and natural gas generation to meet India's future demand.

Other than large scale hydro power, the renewable energy sector in India is still in its infancy. India set up the Ministry of Non-Conventional Energy Sources in the early 1980s (it was renamed the Ministry of New and Renewable Energy in 2006), which was the first of its kind in the world. Despite this, it has been and will be a challenge to maintain or increase the renewables share in India's generation portfolio in the light of a 8-10% growth trajectory. As of 2011, India has roughly 58 GW of renewable capacity, out of 180 GW of total capacity (about 32% of total capacity).[204] Of these renewables, large scale hydro power and wind are the principal resources, with hydro accounting for 65% and wind accounting for 25% of the country's renewables.

[204] Ministry of Power, 2011

Table 7: Cumulative deployment of various renewable energy systems/devices in India as of 30 June 2011

Renewable Energy Program/ Systems	*Target for 2011-12*	Achievement during the month June, 2011	Total achievement during 2011-12	Cumulative achievement up to 30.06.2011
I. POWER FROM RENEWABLES:				
A. GRID-INTERACTIVE POWER (CAPACITIES IN MW)				
Wind Power	*2,400*	237.03	394.68	14,550.68
Small Hydro Power	*350*	23.00	63.00	3,105.63
Biomass Power	*460*	38.00	48.00	1,045.10
Bagasse Cogeneration		-	75.00	1,742.53
Waste to Power, of which: -Urban	*25*	-	-	19.00
-Industrial		-	-	*53.46*
Solar Power (SPV)	*200*	*2.00*	*2.00*	*39.66*
Total	*3,435*	*300.03*	*582.68*	*20,556.05*

Source: Ministry of New and Renewable Energy, 2011

Indian power sector

As of 2011, the total installed electric generating capacity in India was 180 GW.[205] The power sector is dominated by government utilities: of the total installed capacity of 180 GW, 57 GW is owned by the central government utilities, state utilities account for approximately 83 GW, and the private sector accounts for about 40 GW.[206]

[205] Ministry of Power, 2011

[206] Ministry of Power, 2011

This dominance of the government utilities is likely to continue since 68 of the 78 GW of planned addition capacity in the 11th Plan period,[207] will be from government utilities.[208]

Table 8: Structure of the Indian power sector

Authority	Role
Central Governments State Governments	Policy, Governance
Central Electricity Authority State Electricity Regulatory Commissions	Planning
Central Electricity Regulatory Commission State Electricity Regulatory Commission	Regulation
National Load Dispatch Centre Five Regional Load Dispatch Centers State Load Dispatch Centers	System Operators
Central Generating Stations Joint Ventures State Generating Stations Independent Power Producers	Generation
Power Grid Corporation of India Limited	Transmission

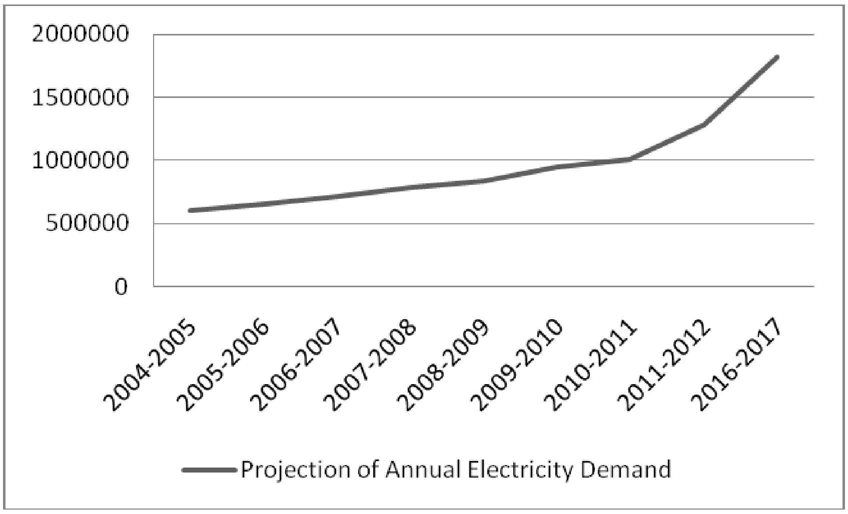
Haphazard demand growth driven by the rapidly growing economy has left India struggling to catch up with electricity demand as power outages affect the country. The most recent Electricity Power Survey, issued in 2007, forecasts a peak demand growth of nearly 10%

[207] India's government maintains a Planning Commission that is charged to "make an assessment of the material, capital and human resources of the country, including technical personnel, and investigate the possibilities of augmenting such of these resources as are found to be deficient in relation to the nation's requirement" and then to "formulate a Plan for the most effective and balanced utilization of country's resources." Plans are published every 5 years, and i the 11th 5-year cycle will end 31 March 2012.). See the Planning Commissions website at: http://planningcommission.gov.in/index.php.

[208] Planning Commission of the Government of India, 2008

through the end of the 11th Plan period (2012).[209] In 2010-11, the Indian generation fleet was only able to produce 97% of its generation target, with interruptions in service resulting.[210]

Figure 10: Projection of power requirement (GWh)



Source: PSI Media Inc., 2010

This situation has a direct bearing on renewable energy expansion as it presents opportunities for policy makers. It is desirable to deploy renewable power systems to diversify supply sources, to avoid combusting fossil fuels for power production, and to provide energy to fill the supply gap in the central delivery system. In addition, there is a need to supply electric services to the 34% of the population that is without electric service at all. Fortunately progress is being made on both fronts.

While, historically, the Indian power sector has relied heavily on public sector ownership, oversight, and regulation, in recent years the government has made a concerted effort to open the power sector to competition and also to privatise.

The Electricity Act of 2003 (Act or 2003 Act) was perceived to be the turning point in this liberalisation process (Parliament of India, 2003). It removes the need to obtain a license for generation projects, encourages competition through bidding, and invites wider private sector participation.

The 2003 Act mandates that State Electricity Regulatory Commissions (SERCs) should promote renewable energy. The Act includes important provisions to accomplish this goal. Specifically, section 61(h) of the Act states that, while specifying the terms and conditions for the determination of a tariff, the appropriate commission shall "be guided by the promotion of cogeneration and generation of electricity from renewable sources of energy." Thus, the

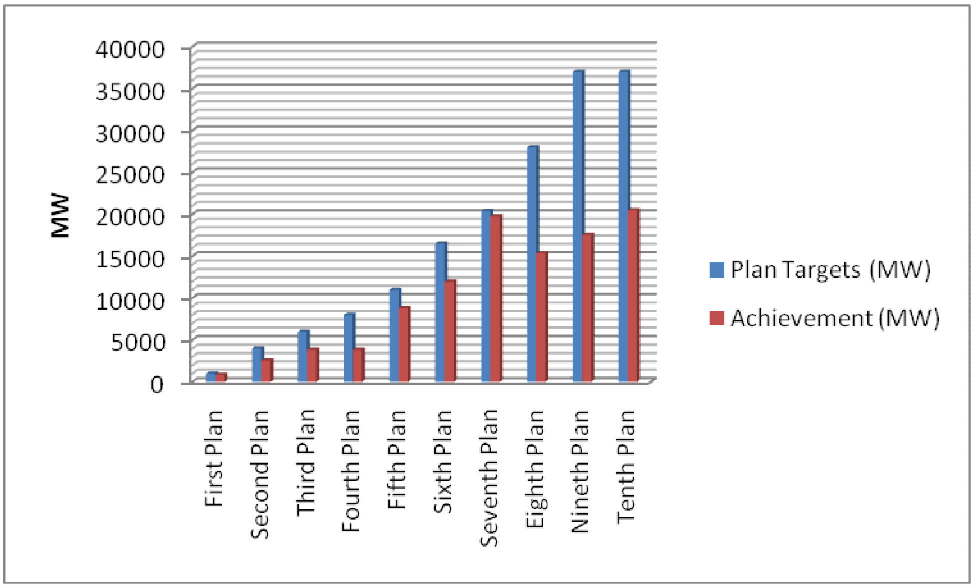
[209] Ministry of Power, 2007

[210] Central Electricity Authority, 2011

2003 Act enlarged the regulatory mandate and role of regulators in promoting clean energy. It provided significant authority to the SERCs to respond to this mandate.[211]

While these and other competitive reforms have helped in reviving the Indian power sector to a significant extent, challenges remain as shown in Figure 11 by the gap between plans and the achieved delivery. In general, even with the enabling policy framework in place, private investment in the power sector in general and transmission in particular has been far from expectations.[212]

Figure 11: Plan target and achievements



Source: Planning Commission, Government of India

Integrating Renewables

India is making a concerted effort to incorporate renewable resources into its electricity system. India established objectives for the energy sector in its long term plans and in 2003 legislation, with a particular focus on solar initiatives and wind energies. The Central Electricity Regulatory Commission (CERC)[213] has developed a series of regulations, guidance on feed-in tariffs and other direction to enable grid integration of renewable energy.

National Solar Mission (NSM)

[211] Although the enforceable level of ambition for RPOs was left to the states, the NAPCC goal of 15% renewables by 2020, and gradually increasing solar-specific RPO prescribed in the 2011 amendment to the National Tariff Policy give national guidance to the state efforts. Poor health of utilities and varying state-level RE resources may dampen state enthusiasm for alignment with national targets.

[212] Chaudhari, 2011

[213] http://www.cercind.gov.in/

In 2008 the Central Government of India unveiled its National Action Plan on Climate Change (NAPCC). It includes a target of 15% renewable energy for the power sector by 2020.[214] In 2010 it launched a major initiative under the NAPCC, the Jawaharlal Nehru National Solar Mission (JNNSM). The targets of the JNNSM include developing 22,000 MW of solar installed capacity by 2022, with 2000 MW off-grid PV, and installing 20 mn remote solar lighting systems in rural areas.[215] The mission will span three planning periods; goals, objectives, and specifics will be re-examined prior to each successive planning period.[216] The 11th plan hoped to address the problem of electricity shortages by adding 78 GW to the generation capacity, with 25% from hydro, nuclear, and other renewables sources.[217]

India is endowed with a rich solar energy resource. "India has an estimated 50 MW/km^2 of potential solar power, of which only about 9 MW had been developed as of December 2009" (Sargsyan, Bhatia, Banerjee, Raghunathan, & Soni, 2011).[218] The desert areas in India, such as in Rajasthan and Gujarat, have sufficient solar radiation for concentrated solar production.

The National Solar Mission (NSM) is one of the eight missions under India's National Action Plan on Climate Change to address climate change mitigation and adaptation. NSM sets a variety of targets, some of which are contingent on the availability of international funding under a possible climate deal.[219] By the end of the 13th plan, in 2022, NSM aims to achieve:

- 20 GW of grid connected installed solar capacity, comprised of large PV and solar thermal power plants and smaller rooftop PV systems;
- 2 GW of off-grid distributed solar plants;
- 20 mn sq. meters of solar collectors for low temperature applications; and
- 20 mn solar lighting systems for rural areas.

The NSM also has two additional goals. First, promotion of research and development (R&D) and public domain information, and developing trained human resource for the solar

[214] http://pmindia.nic.in/Pg01-52.pdf

[215] http://mnre.gov.in/pdf/mission-document-JNNSM.pdf

[216] The Solar Mission will adopt a three phase approach: phase 1 begins during the 11th plan and runs through the first year of the 12th plan (2011-13), phase 2 occupies the remaining 4 years of the 12th plan (2013-17), and concludes with phase 3 (2017-21). See India's Ministry of New and Renewable Energy website at: http://www.mnre.gov.in/.

[217] Planning Commission of the Government of India, 2008. The 11th plan started with target of 78 GW. Partway through it was amended to 62 GW. It ends at end of March 2012, and news last week indicated they may hit 52,000 GW. See: http://www.moneycontrol.com/news/business/india-may-miss-11th-plan-power-capacity-addition-target_585287.html

[218] Yield of energy from solar photo-voltaic (PV) system varies from 4-7 kwh/day per kW of installation at different places on average throughout the year. 6 kWh/day represents a 25%capacity factor.

[219] Ministry of New and Renewable Energy, 2011

industry. Second, expanding the scope and coverage of earlier incentives so that industry establishes PV manufacturing in India (Ministry of New and Renewable Energy, 2011).

As part of its efforts to obtain grid connected solar, CERC developed a feed-in tariff (FIT) mechanism. While successful at obtaining some supply, the process around setting and implementing a successful FIT has been contentious and its ultimate efficacy much debated. The first phase of the NSM FIT is targeting 1000 MW of capacity by 2013. However, the first round of bids witnessed bidding by small operators, many of whom were newcomers to the industry. As a result, there exists a potential failure to deliver on commitments through the bidding process if these projects are not completed later on, due to lack of financing or operational delays (Green World Investor, 2010).

The NSM also sets goals for non-grid connected solar in the form of rural solar power supplies and solar lighting systems. These serve the dual function of expanding basic electric service to the rural areas of India, while doing it in a renewable way. This policy addresses the concerns voiced by some that India is willing to pay large subsidies for grid connected solar, despite a significant portion of its population living without artificially produced light. However, disbursing 20 mn solar lighting systems in rural India is a huge undertaking that will require significant effort and coordination on the part of the ministry. It remains to be seen if this can be accomplished by 2020.[220]

Wind energy development

India has been assessing and building its wind resources vigorously, as well as its solar resources. 2,139 MW of new capacity was installed in 2010, resulting installed wind capacity in India growing by almost 68%. This made it the third largest annual market after China and the USA for 2010.[221]

One of the key financial incentives spurring wind power development is the possibility of developers claiming accelerated depreciation of up to 80% of the project cost within the first year of operation and an income tax holiday on all earnings generated from the project for ten consecutive assessment years.[222]

The government of India is currently moderating the early emphasis on installed capacity with a transition to production based incentives.

Recently India has discovered that its potential, achievable wind resources are vastly greater than hitherto thought. The Global Wind Energy Council (GWEC) released a report in 2009 that asserts India could increase its wind generation fivefold. GWEC estimated India's wind capacity is 231,000 MW, compared to the previous government estimate of 48,000 MW.[223] A

[220] http://www.prayaspune.org/peg/index.php?option=com_k2&view=item&id=160:lighting-up-homes-in-rural-india

[221] GWEC, WISE & IWTMA, 2011

[222] Global Wind Energy Council, 2011

[223] Bloomberg, 2009

study (due to be published shortly) by the Lawrence Berkeley National Laboratory assesses India's onshore wind potential to be well over 700 GW, when taking account of higher hub heights, more efficient turbines and using GIS layers to identify suitable development areas.[224] These and other reports have led to increased interest by Indian policy makers in wind as a significant contributor to India's future generation portfolio. Studies by regulators and others looking at how large wind resources can be integrated effectively into the Indian grid system are taking place.

A number of important factors are changing in India's wind sector which will make the sector's growth even faster than it has been in the past and help it realise its vast newly realised wind potential. For example, in addition to the important 2003 Act, India is beginning to use larger, multi MW turbines at higher elevations, allowing individual turbines to generate more energy. The average size of wind turbine generators installed in India has gradually increased from 767 kW in 2004 to 1,117 kW in 2009.[225] Other examples helping drive wind integration include the introduction of a uniform FIT determination methodology and a tradable REC mechanism across the states.[226]

Even with this growth, there are still barriers to wind development in India which results in low utilisation rates of the country's wind power. For example, there is lack of an appropriate regulatory framework to facilitate the purchase of renewable energy from outside the host state, inadequate grid connectivity, and delays in acquiring land and obtaining statutory clearances.[227] In particular, many of the states with the richest wind resources have inadequate grid infrastructure and have trouble integrating the large amounts of wind energy being produced.[228] Furthermore, "the multiplicity of laws, regulations, and agencies governing the renewable energy sector makes integrated intervention difficult and undermines investor confidence" (Sargsyan, Bhatia, Banerjee, Raghunathan, & Soni, 2011). All of these factors serve to impede the growth of wind as a viable resource, and they all must be addressed if India is to fully realise its vast wind potential.

Conclusion

India's current problem with generating sufficient electricity to meet its ever growing demand remains a major challenge. Although the temptation is to address these future generation needs with fossil fuel generation, India's leaders and public are increasingly aware of economic, environment and other issues that may limit their ability to solve India's power needs. The challenge for India is to recognise and tap into its equally rich renewable

[224] A. Phadke, R. Bharvirkar, J. Khangura. Reassessing Wind Potential Estimates for India: Economic and Policy Implications. Lawrence Berkeley National Laboratory, Berkeley, California. To be published Fall, 2011.

[225] GWEC, WISE & IWTMA, 2011

[226] Sargsyan, Bhatia, Banerjee, Raghunathan, & Soni, 2011

[227] GWEC, WISE & IWTMA, 2011

[228] Global Wind Energy Council, 2011; Sargsyan, Bhatia, Banerjee, Raghunathan, & Soni, 2011

resources, which can meet the need for new power while simultaneously addressing its environmental goals and ambitions for more sustainable forms of energy.

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7. Conclusions

The report addresses different issues by means of 16 case studies reflecting specific contexts. However, by considering and comparing, where possible, the different case studies some general comments can be made:

- In developed countries high volumes of intermittent renewable generation begin to impact security and management of the power system resulting in an increase of the operational costs. This spurs debate on the extent to which renewable generators should be responsible for system imbalances and ancillary services to ensure grid stable (e.g. South Australia, EU countries, USA). In developing countries, power sectors are often characterised by insufficient grid infrastructure and less flexibility in terms of power production, load management and storage. Thus, connecting even a relatively small amount of intermittent generation can exacerbate power system stability and balancing issues. In both scenarios, regulators are faced with similar challenges: to what extent should regulators require renewable generators to bear imbalances risks (e.g. Mediterranean Solar Plan) and to be equipped with devices enhancing their control capabilities (e.g. Mediterranean Solar Plan, China)?

- Electricity markets can help accommodate integration of growing levels of renewable generation into the power system. Two examples are provided in the report. First, the creation of a single European electricity market and the parallel need to adjust market design rules which traditionally have been optimised to the needs of national markets and conventional generation. Second, the Mediterranean Solar Plan, which is by its very nature a supranational scale project and helps promote development of the region's enormous renewable potential. Moreover, in order to facilitate the compliance with EU environmental targets, European legislation envisages cooperation mechanisms to facilitate cross border trade of renewables with non-EU countries which can serve the Mediterranean Solar Plan purposes.

- Energy regulators have to rethink traditional regulatory models and tools (with reference, for example, to planning criteria, cost allocation procedures, business models, etc.) to support large scale deployment of renewable generation. This is reflected in this report, in particular through the case studies related to Canada, Australia (connecting renewables resources located in remote areas), Namibia, Guatemala and Spain (connecting small scale distributed generation).

Some considerations related to the specific topics addressed in each chapter are also highlighted, as set out below.

Chapter 1 on connecting renewable energy to the grid told us that the efforts in Ontario have led to a high uptake of feed-in tariffs, a refined connection process and plan and a system of sharing the costs of connecting renewable generation to the grid among ratepayers. Australia's approach to cross company cooperation demonstrates the advantages of economies of scale, and reveals several possible solutions to the obstacles to collaboration.

This chapter suggested that a broad range of measures is necessary to enable the connection of renewable energy due to the many contingencies that need to be covered, and that the individual situation of each participating company can create barriers to cooperative efforts.

Chapter 2 discussed the impact of wholesale market and system operator arrangements on renewable energy generation. In New England, market allowances made for renewable generation are allowing the systems to develop. In Europe, the Third Package has instigated flexible connection requirements which enable renewable energy to connect. However, problems remain in the form of early capacity allocation which does not allow for the characteristics of intermittent renewable sources, as well as a lack of physical interconnection and incompatible regulatory systems between Member States. These case studies show that whilst some action can and has been taken, progress is still needed, and once again it is cooperation that proves to be a main obstacle.

Chapter 3 focused on the impact of renewable energy generation on conventional generation. It found that there are several possible solutions to these conflicts: the establishment of capacity markets and payments, the exploration of electricity storage and the construction of flexible reserve plants. However, the reaction to the Bonneville Power Authority's proposals demonstrates that the accommodation of renewable sources can create tension with conventional generators. The chapter suggested that, where a market has been designed for conventional generation, changes will have to be made to resolve these tensions in order for renewable generation to become a significant and efficient part of the energy system.

Chapter 4 discussed the legal, financial and socio-economic implications of international renewable energy projects, many of which are positive. The Mediterranean Solar Plan reveals the possibility of optimising natural resources, improved cost-effectiveness, stronger national relationships, financial benefits and skill transference. Again, the difficulty lies in international cooperation when it comes to finance, certification and regulation.

Chapter 5 gave an overview of the issues related to distributed generation by comparing the experiences of Spain and Guatemala with Namibia. In Spain and Guatemala energy markets have been adjusted to provide favourable conditions for distributed renewable generation which has contributed to an increase in the penetration of renewable distributed generation into the grids in both countries. In Namibia a small scale biomass project demonstrated the potential to improve the energy infrastructure and create jobs. However, the energy market is not accessible to RES, the financial sector is too small to provide subsidy and there are few engineers who specialise in renewable energy. Whilst the trial was a success a larger scale project would not work without a new regulatory framework. This demonstrates that the difficulties related to distributed generation can largely be overcome in developed countries, but a lack of infrastructure means the same does not always apply to developing countries despite the high potential of renewable sources.

Chapter 6 looked at the challenges faced by developing countries and suggested that these countries often have high potential RES, in addition to which distributed generation is of particular use across large geographical areas with a fragmented population. There is some regulatory framework in place to support renewable generation in Algeria, but in Malawi renewable generation is prevented by the high upfront costs with no financing, the lack of governmental policy, and no regulatory framework or stakeholder coordination. The implication is that, while the potential, ideas and inclination to establish renewable energy generation are all present, the necessary frameworks are not in place. On the other hand, countries like China, India and Brazil face different, but equally tough challenges to integrate RES in their energy portfolios. These challenges have more to do with the size of their economies and the energy habits developed up to now. In Brazil, there is considerable scope for the development of renewables, due to its endowment of hydro and wind potential. India on the other hand is still keen on continuing using gas and coal to support its energy needs, due to its high natural resources, and this is unlikely to change in the near future. Finally China, despite the many challenges it faces, is making admirable efforts to integrate renewables into its system. Perhaps most importantly, China's central government has made a strong commitment to renewable energy, both in policy and in fact by actual investment.

When it comes to renewable energy generation, where one country is facing difficulties it is often the case that several other countries have trialled potential solutions. Furthermore, the range of experiences expressed in this report's case studies suggests that, whilst individual countries are making progress, in order to make the most of renewable energy's potential there needs to be increased cooperation between companies, industries and internationally. Thus the work of ICER, and this report specifically, reveals areas of mutual interest and demonstrates ways in which countries can work together to improve their own renewable energy generation strategies.

8 List of abbreviations

Abbreviation	**Definition**
ACCC	Australian Competition and Consumer Commission (Australia)
ACER	Agency for the Cooperation of Energy Regulators
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AFUR	African Forum for Utility Regulation
AGC	Automatic Generation Control
ANEEL	Agencia Nacional de Energia Elétrica (Brazil)
BETTA	British Electricity Trading and Transmission Arrangements (England)
BRP	Balancing Responsible Party
CACM	Capacity Allocation and Congestion Management
CAMPUT	Canada's Energy and Utility Regulators
CBEND	Combating Bush Encroachment for Namibia's Development
CCA	Competition and Consumer Act (Australia)
CDM	Clean Development Mechanism
CDM	Conservation and Demand Management (Canada)
CEER	Council of European Energy Regulators
CEPAL	La Comisión Económica para América Latina (Economic Commission for Latin America)
CERC	Central Electricity Regulatory Commission (India)
CET	Central European Time
CREG	Regulatory Commission for Electricity and Gas (Algeria)
CSP	Concentrating Solar Power
DFIG	Doubly Fed Induction Generator
DG	Distributed Generation
DNSP	Distribution Network Service Providers (Australia)
DOE	Department of Energy (USA)
EARS	East African Rift System
ECB	Namibia Electricity Control Board
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas

Abbreviation	**Definition**
ERGEG	European Regulator's Group for Electricity and Gas
ESIPC	Electricity Supply Industry Planning Council (Australia)
ETS	Emissions Trading System
EWEA	European Wind Energy Association
FCAS	Frequency Control Ancillary Services
FCRPS	Federal Columbia River Power System (USA)
FCRTS	Federal Columbia River Transmission System (USA)
FERC	Federal Energy Regulatory Commission (USA)
FIT	Feed-in Tariff
FPN	Final Physical Notification
GCE	Chamber of Management of the Electricity Crisis (Brazil)
GCT	Gate Closure Time
GWEC	Global Wind Energy Council
HFO	Heavy Fuel Oil
HVDC	High Voltage Direct Current
ICER	International Confederation of Energy Regulators
IPN	Initial Physical Notifications
IRP	Integrated Resource Plan
ISO-NE	Independent System Operator of New England (USA)
JNNSM	Jawaharlal Nehru National Solar Mission (India)
MCE	Ministerial Council on Energy (Australia)
MEDREG	Association of the Mediterranean Regulators for Electricity and Gas
MERA	Malawi Energy Regulatory Authority
MIBEL	Iberian Electricity Market
MSP	Mediterranean Solar Plan
NAPCC	National Action Plan on Climate Change (India)
NARUC	National Association of Regulatory Utility Commissioners (USA)
NDP III	Third National Development Plan (Namibia)
NDRC	National Development and Reform Commission (China)
NEL	National Electricity Law (Australia)
NEM	National Electricity Market (Australia)
NER	National Electricity Rules (Australia)

Abbreviation	**Definition**
NERSA	National Energy Regulator of South Africa
NSM	National Solar Mission (India)
NTGDR	Technical Standard of Distributed Renewable Generation (Guatemala)
NTP	National Transmission Plan (Australia)
ODA	Official Aid Development
OEB	Ontario Energy Board (Canada)
ONS	Operador Nacional do Sistema Elétrico (Brazil)
OPA	Ontario Power Authority (Canada)
PFR	Primary Frequency Regulation
PPA	Power Purchase Agreements
PROINFA	Programa de Incentivo a Fontes Alternativas de Energia Elétrica (Brazil)
PTC	Production Tax Credit
PV	Photovoltaics
RAP	Regulatory Assistance Project
REC	Renewable Energy Certificate
RED	Regional Electricity Distributor
REFIT	Renewable Energy Feed-In Tariff (South Africa)
RES	Renewable Energy Sources
RESEB	Restructuring Project of the Brazilian Electric Sector
RET	Renewable Energy Target (Australia)
RIT-T	Regulatory Investment Test for Transmission (Australia)
RNP	Renewable Northwest Project (USA)
ROD	Record of Decision
RRA	Regional Regulatory Associations
SBP	System Buy Price
SERC	State Electric Regulatory Commission (China)
SERC	State Electric Regulatory Commission (India)
SO	System Operator
SSP	System Sell Price
STOR	Short Term Operating Reserve
SVC	Static Var Compensator
TDG	Total Dissolved Gas

Abbreviation	**Definition**
TNSP	Transmission Network Service Providers (Australia)
TSO	Transmission Service Operator
UfM	Union for the Mediterranean
VAD	Distribution Aggregated Value (Guatemala)
VWG	Virtual Working Groups
WFER	World Forum on Energy Regulation
WREGIS	Western Renewable Energy Generation Information System (USA)

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