International Approaches to Transmission Access for Renewable Energy

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A report for Ofgem prepared by:

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EXECUTIVE SUMMARY AND KEY POINTS

This paper provides a brief description of approaches that have been adopted to address the common challenge facing those who own, operate, use and regulate electricity transmission networks in many jurisdictions around the world: how can the actual and anticipated increase in renewable energy generation be reconciled with the risks, high costs and system management issues associated with the expansion and adaptation of transmission infrastructure to accommodate this form of generation?

Wind energy, in particular, provides its own set of challenges. The first is one of coordination: wind developments can be built within a short timeline while the lead time for the development of transmission lines is long. A second follows from the nature of wind energy: transmission systems need to be adapted to accommodate the potential impact of this type of generation on system balancing and security of supply.

Six jurisdictions are examined in this paper, three in Europe (Norway, Denmark and Germany) and three in North America (California, Texas and Alberta). These jurisdictions have been selected on the basis that they share a number of characteristics which allows for useful comparisons to be made, and because they include, some of the 'world-leaders' in renewable energy generation.

The description of the approaches adopted in each jurisdiction is not intended to be a substitute for a more detailed and comprehensive account of the arrangements in these jurisdictions. Rather, the purpose is to draw out the areas that are of most relevance in the context of Ofgem/BERR's Transmission Access Review. In this respect, the paper focuses on five key issues in each jurisdiction: (a) Renewable energy targets and policies; (b) The transmission planning and consents process; (c) Approaches to congestion on the transmission system; (d)The nature and allocation of capacity products; and (e) Recovery of costs associated with system development

The main points to emerge from this review are as follows:

i. The motivations for, and objectives of, renewable policies are strikingly similar across the jurisdictions examined. However, observed outcomes indicate no strong connection between the availability and quality of the natural resource (i.e.: wind) and the achievement of particular targets for renewable energy. This implies that the barriers to the development of wind energy are likely not to be related to natural characteristics, but rather reflect the policy approaches adopted in each jurisdiction. Policy commitment as well as policy design appear to be critical to the achievement of renewable targets.

The Transmission Planning and Consents Process

ii. System planning, including grid investment, is led by transmission system operators in the European jurisdictions. In the North American jurisdictions the responsibility for system development rests with an Independent System Operator (typically a not-for-profit), while investments are undertaken by transmission owners or third parties.

Some of these Independent System Operators, such as CAISO in California, are becoming more proactive in their approach to system development.

iii. The assessment criteria employed when considering expanding the network to accommodate renewable energy has typically been deterministic or policy driven in the European jurisdictions. In this respect, both Denmark and Germany have attracted criticism for paying insufficient attention to cost-benefit analysis. In the United States, California explicitly employs cost-benefit analysis in its assessment of investments, and takes into consideration a range of broader societal, consumer, producer and transmission benefits.

iv. A ‘strategic’ approach to transmission system planning can be seen in some jurisdictions. Germany’s Infrastructure Planning Acceleration law requires transmission owners to pre-invest in the infrastructure necessary for connecting offshore wind parks to the grid, and to ‘bundle’ possible future wind park connections at the planning stage. In Denmark, the system operator develops a long-term energy infrastructure plan to identify areas of future investment, a recent initiative of which is the ‘Great Belt’ interconnector.

v. A significant cause of delay in planning approval for new transmission lines in both Europe and North America is negative public opinion, particularly in respect of possible environmental impacts. In many jurisdictions, local governments and organized residential groups are increasingly active in consent proceedings. Some jurisdictions have sought to address this issue by adopting a ‘one window’ approach to planning consents by involving all affected in a co-ordinated process. In other jurisdictions the planning and consents process has sought to be streamlined by the identification and pre-designation of corridors for development. Consents for projects in these target regions, and the associated permission for grid reinforcements, are effectively ‘fast-tracked’ under this procedure. However, Texas, who adopts this approach, has identified ‘piling on’ or ‘first mover’ problems associated with such corridors, and is considering a range of physical and financial solutions to this problem.

Approaches to congestion on the transmission system

vi. Where it exists, congestion on the system in Europe is typically managed in a ‘zonal’ fashion. A number of electricity markets in the United States are in the process of moving toward a nodal pricing system for electricity, which allows different prices to be set at each generation node that reflect the costs associated with the generation of power, and the relative congestion at that point of the network. Both California and Texas are introducing a re-dispatch process to reduce the amount of electricity from nodes on the so-called ‘source’ side of a constraint, while simultaneously increasing the amount of electricity from nodes on the ‘sink’ side of a constraint.

vii. Various approaches to the trade-off between building additional capacity and ‘managing’ capacity constraints can be observed across the jurisdictions. Norway regards the abolition of all congestion on the network as ‘inefficient’ and always considers better utilisation of existing capacity as an alternative to the construction of new transmission facilities. In contrast, the system operators in Denmark and Alberta exhibit a preference for expanding transmission infrastructure to accommodate increases in renewable energy. In other jurisdictions, decisions appear to proceed on a case-by-case basis.

viii. The increase in renewable energy requiring access to the transmission system has created a short to medium-term congestion management issue in Germany and Alberta. In both these jurisdictions, an approach conceptually similar to the proposed ‘connect and manage’ approach discussed in the U.K has been adopted.

The nature and allocation of capacity products

ix. There is an increasing emphasis in both the Nordic region and in the United States on the offering of both firm transmission capacity as well as capacity at a reduced degree of firmness. These developments are seen as being particularly beneficial in allowing renewable energy sources, such as wind generation, to access the transmission system.

x. In California, the firm transmission rights currently used have both a scheduling and financial aspect, and are defined according to a transmission path from an originating zone to a contiguous receiving zone. Texas currently offers financial ‘flowgate rights’ which allow the holder of the right to collect payments on the basis of a ‘shadow price’ associated with transmission constraints. Both California and Texas are in the process of moving toward a nodal system of electricity pricing which will involve the introduction of Congestion Revenue Rights (CRR) that are financial in nature and entitle the holder to recover a portion of the congestion rents collected by the system operator in managing the network.

xi. The system of feed-in-tariffs used in Denmark and Germany requires eligible renewable projects to be guaranteed firm access rights to the electricity grid upon connection. Additional allocation privileges have been granted in Germany because of concerns that vertically integrated transmission operators could deny access to the grid to new forms of generation. A new law obligates transmission operators to allocate firm access even if necessary grid extension or reinforcement measures are not in place, and to grant privileged access rights for up to ten years after the first feed-in.

xii. In California and Texas, transmission rights are allocated on the basis of an annual auction or in secondary markets. However, in both jurisdictions some rights are automatically assigned to particular parties – such as transmission customers within a defined grid area according to their expected annual congestion charges as well as to companies that invest in new transmission facilities.

xiii. Countries that have transposed the EU Directive on Renewable Energy provide priority access to the grid system for electricity provided by renewable sources. Denmark and Germany are among these, however, system operators in Germany have had to introduce ‘generation management’ measures to restrict the amount of renewable generation feeding-in to the system at particular times because of insufficient capacity on the transmission system.

Recovery of costs associated with system development

xiv. The costs associated with the construction of transmission capacity are recovered in different ways across the jurisdictions. In Denmark and Germany, generators pay only the 'shallow' connection costs associated with connecting the generator to the transmission or distribution grid, with any 'deeper' reinforcement or expansion costs spread over all system users. In Norway and Alberta generators that connect to the network can be required to make a 'contribution' payment towards the costs associated with the reinforcement of the network.

xv. Both California and Germany have established arrangements for the recovery of costs associated with advance investment in the network in anticipation of wind power development. In California, a separate category of network investment recovery has been proposed which permits transmission operators who finance the up-front costs of construction to recover these costs over time as generation resources develop in the area and more connections are made to system. In Germany, transmission owners must incur the 'shallow' costs associated with extending transmission lines to connect to offshore wind parks.

xvi. The infrastructure or fixed charge for using the transmission system in all the jurisdictions examined are zonal or 'postage-stamp' in nature. This means that users are charged the same tariff for transmission service irrespective of their location on the system. In California, the transmission access charge has been evolving toward a single rate over a ten year period from 2001.

xvii. In some jurisdictions, some of the costs associated with renewable policies are recovered through the transmission charge. In Denmark, the fixed transmission tariff includes a Public Service Obligation component which is intended to recover the costs of renewable energy, research and development. In Germany the so-called 'EEG enhancement' costs form part of the use of system charges.

xviii. Transmission rates vary in some jurisdictions according to the location of the generation on the grid and the type of generation. In Denmark and Germany, transmission operators are obliged to purchase renewable energy at fixed prices as a priority. In addition, in some cases, renewable energy sources have been exempt from paying transmission access charges for a specific period. In Norway, a differentiated tariff schemes reduces the grid tariff for generators located in certain areas where it is documented that new generation will bring grid savings.

INTRODUCTION

A common challenge faces those who own, operate, use and regulate electricity transmission networks in many jurisdictions around the world: how can the actual and anticipated increase in renewable energy generation flowing from various policy initiatives be reconciled with the risks, high costs and system management issues associated with the expansion and adaptation of transmission infrastructure to accommodate this form of generation.

The purpose of this paper is to provide a brief description of some of the approaches that have been adopted to address these issues in a small number of jurisdictions that share common characteristics. However, the issues discussed in this paper are likely to have relevance to any jurisdiction that has set renewable energy targets. Of such widespread concern are these issues that a central focus of the 2008 G8 summit will be on how to efficiently increase the share of renewable electricity through evolution of transmission systems and markets.

1. Common challenges of coordination and adaptation

Wind generation relies on high average wind speeds which means sites are often located far away from the main areas of consumption and conventional generation, and new transmission infrastructure must be developed to transport the electricity produced to where it is consumed. An initial challenge is one of coordination: wind developments can be built within a short timeline (within 6 months), while the lead time for the development of transmission lines is estimated to be between 3 to 15 years.

A second challenge involves the adaptation of the transmission system to accommodate the potential impact of wind generation on system balancing and security of supply. Unlike conventional forms of generation, which typically employ synchronous machines that are able to meet the stability and security requirements of system operators, wind power has – to date – offered a less predictable and secure form of generation. This is, in part, a natural function of its fuel source (i.e.: wind) but also reflects factors such as how much it complements the existing loads on the system, and its physical location on a transmission network.[1]

2. Identifying the barriers and policy responses

The motivations for, and objectives of, renewable policies are strikingly similar in many jurisdictions and typically involve increasing the share of electricity produced through renewable sources, particularly wind. However, successive studies and policy reviews indicate that there appears to be no strong connection between the availability and quality of the natural resource (i.e.: wind) and the achievement of particular targets for renewable energy across jurisdictions.

[1] For example, it has been estimated that where loads are well matched wind penetration can be in the range of 30-40% without compromising the reliability of the system. However, in less matched systems or where they are isolated the percentage may be as low as 10%.

This suggests that the barriers to the development of wind energy are likely not to be related to natural characteristics, but rather reflect the policy approaches adopted in each jurisdiction. As the discussion below suggests, there have been a wide-range of policies and initiatives adopted across jurisdictions to address the problem of wind generation development, a major element of which is the policy in relation to transmission access. Some of these policies reflect standard approaches to issues such as transmission investment in network industries. However, others are notable for their innovative and forward-looking nature. In all cases, it appears that both policy design and policy commitment are important ingredients to the likely success in achieving the various renewable targets set.

Four key policy areas are discussed in this paper:

(a) Transmission planning process

The planning and consents process is central to the development of renewable energy in all of the jurisdictions examined. In particular, who leads the process and the criteria taken into account when deciding whether or not to allow new transmission infrastructure appear to be central factors. A particular focus is on whether any streamlined or 'fast-track' routes for the planning and approval of infrastructure related to renewable energy have been introduced. This discussion also examines whether the system planning process in each jurisdiction involves the identification of 'strategic' investments in transmission capacity in anticipation of future growth in renewable energy.

(b) Approach to congestion on the transmission system

The integration of greater amounts of renewable energy onto the transmission network can lead to the development of new or intensified areas of congestion on the transmission system. A particular focus is whether jurisdictions are dealing with this through the development of more sophisticated congestion management schemes or by pre-emptive 'overbuild' of additional transmission capacity

(c) The nature and allocation of capacity products

The ability for renewable energy sources to access the transmission grid can be affected by the nature and availability of the capacity products. More specifically, the relative firmness and period over which the access rights will be provided can potentially influence: the amount of renewable energy that can initially be connected to the grid; the requirements that renewable energy generators must comply with in order to remain connected; and the allocation of the rights of access the grid over the long-term. This section briefly describes some of the key characteristics of the different types of access products that are available in each jurisdiction. In addition, it examines how access rights are allocated in each jurisdiction, and, in particular, whether any type or form of generation has preferential access to the transmission grid.

(d) Recovery of costs associated with system development

In general terms, the costs and benefits associated with the development and expansion of the transmission system to accommodate renewable energy are potentially widely distributed, and the appropriate allocation of these costs among transmission operators and existing and new users is one of the central challenges faced in jurisdictions that are expecting large increases in renewable energy in the near future. The various elements underlying this challenge are examined in this sub-section for each jurisdiction. This includes a discussion of how the new construction costs are allocated among the transmission owners and users, the extent to which costs are locational or spread over a broader area, and whether any special discounts apply for renewable energy in the relevant jurisdictions.

The discussion in each section begins with a brief overview of the principal institutions and regulatory structures in each jurisdiction, and the relevant renewable energy policies and targets that have been adopted.

3. Jurisdictions examined

Six jurisdictions are examined in this paper: Norway, Denmark and Germany in Europe, and California, Texas and Alberta in North America. These jurisdictions have been selected on the basis that they share a number of characteristics which allow for useful comparisons to be made. First, each jurisdiction has established some form of renewable energy policy or target and is actively considering the appropriate policies and measures required to satisfy these targets. Second, each of the electricity markets in the jurisdictions have undertaken measures to 'liberalise', or open up, the market to competition in recent years. Third, while the jurisdictions differ in important respects, all of them are situated in highly-industrialised economies and therefore have a number of key structural and contextual factors in common. Finally, despite adopting varied approaches, the majority of the jurisdictions examined are among the 'world-leaders' in successfully integrating renewable energy onto the transmission grid (Denmark, Germany, California and Texas in particular).

The description of the approaches and policies for each jurisdiction is in no way intended to be a substitute for a more detailed and comprehensive account of the arrangements in each jurisdiction. Rather, the purpose is to focus on drawing out the areas that are of most relevance to current discussions in the context of Ofgem/BERR's Transmission Access Review.

4. Structure of paper

The discussion in this paper is divided between European approaches to transmission access, and approaches adopted in North America. It has been arranged in this way to take account of the interaction between different levels of law and policy at the federal and state level in the United States, or in the case of Europe at the EU (or EEA) level and Member State level. The 2001 EU Directive on Renewable Energy, for example, was transposed into national law in both Germany and Denmark, and in the case of Norway under the EEA agreement.

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EUROPEAN APPROACHES

A: Background and Renewable Energy Targets

All EU Member States are required to set national indicative targets for the consumption of electricity produced from renewable sources.[2] There is also a current EU-wide target of 21% of electricity to be generated by renewable sources by 2010. A recently proposed Directive would set an EU wide target of 20% share of renewable sources in energy consumption by 2020.[3] This Directive would also include specific targets for each Member State.

1. Norway

Norway has one of the highest proportions of renewable energy anywhere in the world and the Norwegian government's target is that 90% of electricity production should be sourced from renewable energy (including hydropower) by 2010.[4] To date, however, there has been relatively little wind power development in Norway, in part, because of the abundance of hydropower. This appears to be changing and there are plans to develop a number of wind farms in Northern and mid- Norway.

Norway has transposed the EU renewables directive of 2001 into the European Economic Area agreement, and is therefore committed to complying with its requirements. To assist the development of (non-hydro) renewable energy sources such as wind, the Norwegian government has established a state-owned company, Enova, which is responsible for supporting the development of renewable energy and has been endowed with an ability to administer grants of up to 5 billion NOK over a ten year period. Among the objectives of Enova is the installation of wind power capacity of 3 TWh by the year 2010.

In January 2007, a scheme of mandatory green certificates (RECS – renewable energy certificate scheme) was introduced. It is expected that the RECS system will aid the development of wind power, and as a consequence will trigger a need for investment in the main transmission grid. According to some estimates the investments in the grid associated with this scheme may be up to NOK 7/5 billion to 2020.

85% of the Norwegian electricity transmission grid is owned by Statnett, a state owned enterprise, the remainder being owned by regional grid owners and rented to Statnett under a Central Grid Agreement. Statnett is also the system operator and is responsible for activities

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[2] European Council 'Directive on Electricity Production from Renewable Energy Sources', 2001/77/EC, 27 September 2001
< http://eur-lex.europa.eu/pri/en/oj/dat/2001/l_283/l_28320011027en00330040.pdf>

[3] European Commission 'Proposal for a Directive of the European Parliament and the Council on the promotion of the use of energy from renewable sources' COM(2008) 19 final, 23.1.2008
< http://ec.europa.eu/energy/climate_actions/doc/2008_res_directive_en.pdf>

[4] 'Norway focuses on renewable energy' <http://www.norway.org/News/archive/2004/200405_energy.htm>

relating to system dispatch and ancillary services procurement, and therefore for identifying areas of system development and for undertaking the necessary works.

Statnett's activities as both transmission owner and system operator are regulated by the Norwegian Water Resources and Energy Directorate (NVE), which is a directorate of the Ministry of Petroleum and Energy.

Statnett co-operates with the transmission system operators (TSOs) of Sweden, Finland and Denmark under a voluntary association (Nordel) and accedes to a grid code which sets out the principles, rules and guidance for a common framework of system operation across the four jurisdictions. The four Nordic countries also operate a single market for trading electricity across the four jurisdictions (Nordpool) and the regulators of each of the four Nordpool countries cooperate through an association known as NordREG.

2. Denmark

Denmark produces over 18% of its electricity from renewable sources – the largest percentage in the world – which exceeds a 10% target it set in 2005. The current target is for 30% of energy consumption to be renewable by 2030, including a target of 4000 MW of offshore wind capacity.

Denmark has used a combination of tax and subsidy policies to support the development of wind energy. These policies have included entering into voluntary agreements with electricity utilities to build the required capacity and mandating that utilities pay for transmission network upgrades to support wind capacity additions. Denmark has three government supported offshore wind farms, including the world's largest at Horns Rev.

In the past, wind generators were guaranteed a fixed price and preferential access for their renewable energy, irrespective of how much was generated. However, this has changed and only a certain percentage of electricity from renewables is guaranteed to be sold on the market (up to 43%), and the so-called 'feed-in-tariff' has been modified so that the price paid relates to the Nordpool market price.

The TSO in Denmark is Energinet.dk, a state owned company that is both the transmission owner and system operator and is responsible for both the electricity and gas networks. Energinet.dk is therefore responsible for identifying areas of investment in the network, and for undertaking such investments.

The regulatory oversight of Energinet.dk is shared between Danish Regulatory Authority (DERA) and the Danish Energy Authority (DEA). The DEA is responsible for the overall planning of the Denmark's electricity supply, while DERA is responsible for setting tariffs and for approving new investments as well as ensuring that the terms of open access to the grid are complied with.

As discussed in relation to Norway's TSO, the TSO of Denmark is a participant in Nordel, Nordpool and NordREG.

3. Germany

The renewable goals in Germany are to increase the share of renewable energy in consumption to 12.5% by 2010, and to at least 25% by 2020. A 2007 estimate of the renewable share in electricity consumption was 14%, already exceeding the 2010 target.[5] The renewable energy sector has been strongly supported in Germany by the introduction of specific legislation to aid the development and connection of new generation sources and the necessary transmission infrastructure (discussed further below).

Germany has implemented the various elements of the EU Directive on renewable energy. Accordingly, renewable energy sources have priority access to the grid and the transmission system operators are obliged to buy power from renewable energy sources. To promote the development of renewable energy Germany, like Denmark, also uses a system of 'feed-in-tariffs' to guarantee the price that is paid for renewable energy (although this has been amended a number of times).

Germany has the highest share of installed wind energy capacity in the world with an estimated 18,685 wind turbines with a combined capacity of 20,600 MW. On land, the wind power production is concentrated in Northern Germany, particularly in Schleswig-Holstein Länder. As with Denmark, citizen owned wind farms have been popular.

Germany's future renewable energy is likely to be principally sourced from large scale offshore 'wind parks'. There are current plans to build a cluster of wind farms – known as Borkum 2 – some 100 kilometres off the coast which in combination will supply some 400 MW of power. In addition, there are currently 1336 licensed sites for wind power production in the North and Baltic seas, the majority of which are located between 30km to 80km offshore. A total of 25,000 MW in capacity is estimated to be installed in offshore wind parks in the German North and Baltic seas by 2030.

The high-voltage transmission system is Germany is owned by four separate companies that are responsible for developing and managing the network in different geographical areas. In the Western part of Germany surrounding the Rhine- Ruhr the TSO is RWE, the south-west area of Germany is controlled by EnBW, while the TSO in the eastern part of Germany is Vattenfall. Finally, E.ON Netz is the responsible TSO for an area down the centre of Germany extending from Schleswig-Holstein in the North to Bavaria in the South.

The Federal Network Agency (BnetzA) is responsible for the regulation of the four national TSOs. It regulates the terms and details of third party access, and oversees issues relating to investment and connection to the system. BnetzA is a separate higher Federal Authority, and is part of the Federal Ministry of Economics and Technology.

B: Transmission planning process

The European Commission estimates that the approval and development of new transmission lines in Europe currently takes between 10 to 15 years. It attributes the length of this process not to policy decisions, but to delays in authorisations and to slow reinforcement and

[5] Federal Ministry for Environment, Nature Conservation and Nuclear Safety 'Big boost for renewables energy' press release, 22 January 2008. <http://www.bmu.de/english/current_press_releases/pm/40791.php>

extension works on transmission grids. In its most recent assessment of the implementation of the EU Directive on renewable energy, the Commission advocates the immediate lifting of administrative barriers and a simplification of the approval procedures.[6] The Commission also suggests that work should begin on the development of an offshore European ‘super grid’ for wind power.

1. Norway

(a) Systems Planning and Consents

The Nordic Grid Code outlines some high-level principles and common requirements and procedures to govern the planning and development of the Nordel power system including rules to be observed by the four Nordic TSOs in developing their networks. However, the Nordic Grid Code is subordinate to national rules in the four jurisdictions and planning approval occurs at this local level.

The planning consents process in Norway is based around a ‘one window’ approach. This means that all parties affected by a proposed new development, including reinforcements or expansion to power lines, are included in a single process coordinated by NVE. The relevant municipality plays an active role in this process, making the plans and any environmental impact assessments available to the local population, and submitting its own evaluation of the development to the NVE.

In its decision the NVE can reduce the scope of the project or propose that the application be rejected. NVE's recommendation is then forwarded to the Ministry of Petroleum and Energy for final approval.

(b) Assessment criteria employed: deterministic, cost-benefit and reliability

The evaluation criteria used by the NVE in the assessment of proposed transmission system developments comprises a consideration of all the costs and benefits of the project including environmental issues. In addition, in making its assessment NVE is required to address every question raised during the process of public hearings.

Statnett’s internal assessment criterion for expansions to the network is based on a ‘window of opportunity’ approach that determines the necessity of reinforcements according to set limits for how large outages are acceptable at different parts of the network. Accordingly the grid will only be strengthened if it is economically rational to do so, or if it has to be done to satisfy the limits in the given ‘window of opportunity’.[7]

Grid planning in Norway is based on the Nordel agreed ‘n-1’ criterion, which means that a system must be able to tolerate the breakdown of one component without causing an outage in electricity supply. The ‘n-1’ was previously a decision-making criterion, but now is used more as an aid in planning in Norway.

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[6] European Commission ‘Green paper follow-up action. Report on progress in renewable energy’, COM (2006) 849 final, 10.1.2007

[7] Statnett ‘Grid Development Plan 2005-2020’, June 2005 page 7.

As the TSO, Statnett is responsible for planning and investment in the Norwegian transmission system and all international connections. Statnett issues a long-term national grid study (10 – 20 years) identifying areas of structural congestion in the network. Despite major increases in electricity consumption in the last ten years, only one large new transmission line has been built in Norway. In its most recent grid development plan, Stattnett identifies the lengthy planning, development and construction process associated with new power lines as a significant challenge.[8]

2. Denmark

(a) Systems Planning and Consents

In broad terms, the planning issues associated with the necessity for grid expansions for Danish wind projects have been assisted through the identification and designation of strategic areas for renewable development. Consents for projects in these target regions and the associated permission for grid reinforcements have effectively been 'fast-tracked' under this procedure. Local municipalities have been required to allocate such zones since 1994, and, moreover, have been obliged to involve counties, local non-governmental organisations and utilities in the planning and consents phase. There has been a high proportion of local ownership of wind power in Denmark, which has been seen as being an important contributing factor to widening support for, and mitigating potential objections to, wind power developments.[9]

The majority of on-shore wind capacity in Denmark has to date been connected to local distribution systems, and not to the major transmission network. The development of large offshore wind farms is, however, expected to substantially impact the main transmission grid and Energinet.dk predicts that these developments will mean that the planning consents process, which has been given marginal consideration to date, is likely to be replaced by more a rigorous process and standardised requirements.

The Danish TSO Energinet.dk is responsible for system planning and investment in the Danish electricity grid and is required to develop a comprehensive annual system plan which outlines any future investments. This plan must be submitted to the Minister of Transport and Energy prior to initiation of any work, and projects of a certain size must obtain the relevant approvals (environmental) and also receive the prior approval by the minister. In relation to specific projects, a 'needs-case' must be established and approval must be sought either from the Ministry for Transport and Energy for larger projects, or from the Danish Energy Agency.

(b) Assessment criteria employed: deterministic, cost-benefit and reliability

The Danish approach to evaluating proposals for renewable energy has been largely policy driven. This approach has been criticised as giving insufficient attention to cost-benefit analysis, and, in particular, for defining costs too narrowly to exclude the costs of upgrading

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< http://www.statnett.no/Resources/Filer/Dokumenter/Div.%202005/Nettutvikling_Engelsk_trykk.pdf>

[8] ibid page 4

[9] Some estimates suggest that over 80% of wind turbines installed in Denmark have been installed by local cooperatives. These cooperatives are seen to have reduced local opposition, and more importantly generated a 'stake' in the wind industry for the broader public.

the transmission network.[10] The OECD has stated frankly that "the [Danish] renewables programme, now largely based on wind turbines, seems to have incurred costs much higher than any environmental benefits achieved so far".[11]

Denmark employs the 'n-1' reliability criterion in system operation and planning development. To date the network has successfully dealt with issues relating to wind intermittency and system reliability, although it is widely agreed that this is, in part, a function of its reliance on the strong interconnections with neighbouring Nordel markets that are based on hydropower.

The TSO in Denmark (Energinet.dk) publishes an annual transmission report which describes the alterations and expansion requirements in relation to the electricity transmission grid. These plans are designed to be consistent with the Danish government's Energy Strategy 2025. In addition to taking into account issues relating to security of supply and system reliability factors assessed include environmental issues and other socio-economic factors.

(c) Role of 'strategic' investments in transmission capacity

Following high profile electricity failures in 2003, the Danish government requested Energinet.dk to develop a long-term energy infrastructure plan to identify areas of investment in new major transmission network to ensure security of supply and to accommodate future growth in renewable energy.

This plan was published in 2005 and, among other measures, it proposed the construction of a 'Great Belt' interconnector to connect the Western and Eastern grid (currently not synchronously connected). This plan was approved by in 2005 and is now awaiting approval by the Minister of Transport and Energy.[12]

3. Germany

(a) Systems Planning and Consents

In Germany, the responsibility for planning approval is conducted at a local level and is typically overseen by the relevant authorities in each Länder. The process of approval can take up to ten years and may involve legal proceedings. As is the case elsewhere, the principal barriers to consent approval include negative public opinion, in particular in respect of possible environmental impacts.

To address some of the issues associated with the planning and development process the German government recently introduced two pieces of legislation. The Infrastructure Planning Acceleration Act 2006 (*Infrastrukturplanungsbeschleunigungsgesetz*) seeks to achieve economies of scale in construction and planning by making the TSOs responsible for

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[10] International Energy Agency 'Energy Policies of IEA Countries – Denmark 2006 Review' June 2006 < http://www.iea.org/Textbase/press/pressdetail.asp?PRESS_REL_ID=181>

[11] OECD 'Encouraging environmentally sustainable growth in Denmark' Economics Department Working Papers No. 277, pages 17, 20 and 31

[12] Energinet.dk 'The Storebaelt link' <http://www.energinet.dk/en/menu/Transmission/Construction+work/Great+Belt/The+Storebaelt+link.htm>

the planning and financing of the grid connection from an offshore wind farm's transformer station to the onshore transmission grid. The aim is for TSOs to adopt a systematic planning approach by 'bundling' possible future wind park connections at the planning stage, thereby avoiding a one-windfarm-one-cable type planning and development process.

The second Act relates to new connections to the grid (*Netzanschlussverordnung - KraftNAV*) and is intended to encourage and expedite the construction of new power plants. Under this law, TSOs must undertake all reasonable measures to make the grid suitable for additional feed-in of new generation, including improving connection points or extensions of the grid. A timetable for grid extension measures must also be provided with the threat of sanctions for construction delays. Critically, under this law, a TSO is not permitted to refuse a connection on the basis that it will increase congestion.

(b) Assessment criteria employed: deterministic, cost-benefit and reliability

The identification and assessment of transmission works are undertaken by the four TSO's in Germany for each of their control areas. The four German TSO's occasionally develop joint forecasts and plans for the development of the high-voltage grid to provide an 'all-German' overview of the future necessary transmission capacity between grid regions.

TSO's are required to submit periodic reports to BnetzA which detail proposed developments to the grid. The analysis of BnetzA on the first of these sets of reports was released in January 2008. Looking ahead, as BnetzA moves toward introducing elements of incentive based regulation for the TSOs it is likely that it will exercise a higher level of oversight on the criteria used by the TSO's in determining whether or not to undertake particular investments. For example, although the TSO's are required under the Infrastructure Acceleration Planning Act to develop plans for laying offshore transmission lines the BnetzA has instructed the TSOs to undertake the offshore cable planning as inexpensively as possible to ensure full cost recovery.

Recent TSO reports show substantial investments are planned for the high voltage network, in part to accommodate the large amount of wind energy expected to be produced in Northern Germany.[13] Germany uses the 'n-1' contingency criterion for system planning for the high and extra high voltage networks, and this criterion is also being adopted for the development of the offshore transmission system.

As with Denmark, Germany has been criticised for the high costs associated with its renewable policy initiatives. A 2006 OECD report on Germany was critical of the approaches adopted noting that goals could be achieved at lower cost, and that direct and indirect subsidises to support the sector and necessary investments should be reduced more quickly over time.[14]

(c) Role of 'strategic' investments in transmission capacity

The German government has recently adopted what could be described as a strategic approach to investment in support of the future development of offshore wind energy,

[13] See, for example, RWE press release of 1 February 2008, suggesting investments of 3 billion euros required <http://www.rwetransportnetzstrom.com/generator.aspx/press/language=en/id=76186/press-page.html>

[14] OECD economic surveys Germany 2006 'Sustained competition is absent in energy markets' chapter 5 < http://www.oecd.org/dataoecd/24/63/36789821.pdf>

particularly through its Infrastructure Planning Acceleration law which, requires TSO's to invest in the infrastructure necessary for connecting offshore wind parks to the grid in advance of connections.

More generally, a series of strategic grid studies have been commissioned by the German Energy Agency (DENA). Steered by representatives of the German Ministry of Economy, the wind energy branch, major utilities and their associations, the studies aim to identify the long-term consequences of an increased share of renewable energy on the electrical system, including the required grid upgrades and extensions. Some of the recommendations of the first DENA study are progressing to the consenting phase.[15] DENA's second study, which is currently being undertaken, is examining the technical and organizational solutions to accommodate 30% of renewable energy including 20 GW from offshore wind.[16]

C: Approach to congestion on the transmission system

1. Norway and Denmark

(a) General approach to congestion on the network

In general terms, congestion across the Nordel area is managed by market splitting, counter trading and reduction of cross-border trading capacities. To manage congestion that occurs at national borders, a system of implicit auctions is employed which effectively splits the market in times of congestion into a number of zones including north, middle and south Norway, Sweden, Finland and Denmark.

The primary mechanism for handling grid congestion is the NordPool Elspot market which, in times of congestion, divides the Nordel system into separate bidding areas which ultimately become separate price areas if the contractual flow between bidding areas exceeds the capacity previously allocated by the TSOs. Any congestion rents that arise as a result of this management procedure are presently collected by NordPool as part of the implicit auction process, and are divided equally among the TSOs that are involved. Finally, any additional grid congestion that occurs in real-time is managed by the individual Nordic TSO's by calling bids in the real-time market.

The internal congestion management process in Norway is fully integrated with the functioning of the NordPool Elspot market described above, and is therefore handled via the implicit auctioning and market splitting processes.[17]

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[15] Deutsche Energie-Agentur (DENA) 'Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020' March 2005 <http://www.dena.de/fileadmin/user_upload/Download/Dokumente/Projekte/kraftwerke_netze/netzstudie1/dena-grid_study_summary.pdf>

[16] Deutsche Energie-Agentur (DENA) 'Grid Study II' < http://www.dena.de/en/topics/thema-reg/projects/projekt/grid-study-ii/>

[17] Market splitting involves the partitioning of nodes into pre-defined price areas on either side of the transmission constraint on the basis of available capacity as declared by the TSOs. This process is characterised as an implicit auction where transmission capacity is allocated simultaneously with electricity trade through a spot market.

The approach to congestion between Denmark and its interconnections with Norway and Sweden is managed via the implicit auction process in the Elspot market. A system of explicit auctions is used to address any congestion on the UCTE interconnection between Western Denmark and Germany.

Energinet.dk reports no enduring congestion problems on either the Eastern Denmark or Western Denmark transmission systems since 2004 when the Western Denmark grid was upgraded. Where temporary real time congestion arises, it is managed through a series of counter trades within the relevant price area in what is known as the regulation power market. In such situations, Statnett purchases or sells power on either side of the congested line to manage the constraint.

(b) How the decision to build versus manage constraints is resolved

The general position adopted by the association of NordREG is that it is 'inefficient' to abolish all congestion on the Nordel network by undertaking investments in new capacity in all circumstances, as these investments are ultimately financed by higher charges paid by TSO customers.[18]

In Norway, Statnett always considers utilisation of the existing grid as an alternative to the construction of new transmission facilities, taking into consideration issues such as estimated outage costs. For example, in response to expected future increases in generation, it reports it is continuing to work on measures to increase utilisation including power upgrades on certain lines to carry a higher load, and voltage upgrades where possible. The specific purpose of these measures is to avoid or postpone the construction of new power lines, and Statnett proudly notes that over the last 10 years it has only built one large power line.[19]

Conversely, the system operator in Denmark indicates a preference for developing new transmission infrastructure to accommodate the expected increase in renewable energy. Energinet.dk's stated position is that transmission infrastructure must support the increasing use of renewable energy, and consequently that it will expand the transmission grid to accommodate this development.[20] In particular, Energinet.dk considers that that the Danish transmission grid will need to be expanded to accommodate the demands on the transmission system associated with the development of new offshore wind farms and the expansion of existing ones.

2. Germany

(a) General approach to congestion on the network

There is presently no systemic congestion on the domestic lines within Germany. The four German TSO's employ various management and re-dispatch measures to manage any congestion as it arises. This includes short-term changes in the distribution of the feed-in of new power within different regions.

[18] NordREG 'Regulation of the Nordic TSOs - with focus on Market Efficiency and Harmonisation' Report 7/2007 page 26

[19] Statnett 'Utilisation of existing grid' < http://www.statnett.no/default.aspx?ChannelID=1354>

[20] Energinet.dk 'About Planning' <http://www.energinet.dk/en/menu/Planning/About+planning/About+planning.htm>

As noted above, this situation is expected to change, and a 2008 BnetzA report notes that significant investment is needed in the German power grid if it is to avoid structural congestion emerging in the domestic in the medium term in some regions of Germany.

There is currently congestion at all German interconnections with other countries, with the exception of Austria. This congestion is typically handled through a system of explicit auctions (discussed in more detail below).

(b) How the decision to build versus manage constraints is resolved

The traditional response of the four TSO's in Germany to increasing requests for connection has been to expand the network at the expense of those seeking access, rather than taking actions to manage or utilize the network more effectively.[21] However, BnetzA now exercises greater control over the TSOs' network expansion projects, and seeks justification of choices by requiring network expansion and condition reports to be produced, made available to third parties, and subject to review by BnetzA.

Nevertheless, the preference for expansion rather than management may, in part, be attributable to the obligations imposed on TSO's under the 2004 Renewables Law, which requires TSOs to connect *all* renewable energy projects to the grid when requested regardless of capacity, and then to undertake the necessary reinforcements. This increase in renewable energy requiring access to the transmission system has created a short to medium-term congestion management issue in Germany. The vast majority of Germany's current and expected wind capacity is located in the Northern Länder of Schleswig-Holstein, or off the coast, and according to E.ON Netz (the TSO in this region) the transmission system in this area operates at close to its capacity, and in specific conditions requires what is known as 'generation management'.

The generation management approach – which is conceptually similar to the 'connect and manage' approaches proposed in the U.K – involves constraining off non-renewable generation in times of constraint, and failing this, allows the TSO to restrict renewable generators. This approach is regarded as a medium-term solution to the timing problems associated with the development of sufficient transmission capacity, and is not therefore seen as being inconsistent with Germany's Renewables Law or the EU Renewables Directive – which require that renewable energy sources be given priority access to the transmission system – over the longer term. Currently there is no compensation paid to generators who are managed under this approach, and all new renewable generators connecting to the grid in certain areas must be willing to participate in these generation management procedures as a term of access.

BnetzA is examining the potential magnitude and impacts of the timing issues associated with the changing generation pattern in Germany, and specifically what measures can be undertaken to address the potential for congestion emerging in the medium-term.[22] In a recent

[21] Federal Network Agency 'National contribution to the EU benchmarking report' 2006, page 14 <http://www.ceereu.org/portal/page/portal/ERGEG_HOME/ERGEG_DOCS/NATIONAL_REPORTS/2006/E06_NR_Germany-EN.pdf>

[22] Federal Network Agency 'National contribution to the EU benchmarking report' 2007, page 26 <http://www.ceer-eu.org/portal/page/portal/ERGEG_HOME/ERGEG_DOCS/NATIONAL_REPORTS/National%20Reporting%202007/E07_NR_Germany-EN.doc>

[23] Federal Network Agency 'Methodische Fragen bei der Bewirtschaftung innerdeutscher Engpässe im Übertragungsnetz (Energie)' February 2008 <http://www.bundesnetzagentur.de/media/archive/12789.pdf>

report commissioned by BnetzA, the possibility of moving away from short-term generation management based approaches to other more formalised methods for managing congestion – such as market based redispatch or market splitting – is considered.[23] The report concludes that while the market splitting approach in particular is appealing in principle, the implementation costs associated with such a shift are considered too great in advance of significant amounts of congestion developing on the network. In addition, there are concerns that such a market splitting approach may exacerbate problems associated with regional concentration in generation. In the short to medium term, therefore, the report suggests that the current approach of cost-based redispatch to managing congestion be maintained, subject to some modifications.

D: The nature and allocation of capacity products

A number of the jurisdictions in Europe have transposed the requirements of the EU Directive on Renewable Energy (2001/77/EC) into national legislation. Article 7 of this Directive requires TSO's to provide for priority access to the grid system of electricity provided by renewable sources, so far as the operation of the national electricity system permits.[24] It is noted that there have been some calls for re-consideration of these priority rules on the basis that they discriminate against conventional electricity and also against renewable electricity from other Member States.[25]

1. Norway and Denmark

(a) The nature of capacity products

NordREG's congestion management guidelines directs that the four TSO's in the Nordel region seek to optimise the amount of firm transmission capacity, and to offer a 'reasonable fraction' of capacity at a reduced degree of firmness.[26]

In Norway, network operators are encouraged to introduce special tariffs for interruptible transmission to stimulate the use of alternative energy responses at particular times. These tariffs for interruptible transmission include reduced obligations as to supply from the grid in specific circumstances, and consist of an energy component and a fixed component which covers the minimum specific costs.

Financial transmission rights do not exist in the Nordic region, however, the use of Contracts for Difference (CfD) in these markets share a number of similarities with financial transmission rights as used in other jurisdictions. In both cases the purpose of these rights is

[23] Federal Network Agency 'Methodische Fragen bei der Bewirtschaftung innerdeutscher Engpässe im Übertragungsnetz (Energie)' February 2008 <http://www.bundesnetzagentur.de/media/archive/12789.pdf>

[24] Article 7 of 'Directive on Electricity Production from Renewable Energy Sources', 2001/77/EC, 27 September 2001 < http://eur-lex.europa.eu/pri/en/oj/dat/2001/l_283/l_28320011027en00330040.pdf>

[25] European Transmission System Operators 'European Wind Integration Study (EWIS) Towards a Successful Integration of Wind Power into European Electricity Grids' 15 January 2007 page 4 < www.etso-net.org/upload/documents/Final-report-EWIS-phase-I-approved.pdf>

[26] NordReg ' Congestion Management Guidelines' Compliance Report 8/2007, page 11 < https://www.nordicenergyregulators.org/upload/Reports/congeguidelines.pdf>

not to provide physical access rights to the grid. However, in the Nordic market, CfD's are not linked to the congestion rent that the system operator collects, rather the CfD reflects the difference between an area price and the NordPool spot price. In addition to CfD's, there are a range of other financial products (futures, forwards and options contracts) traded on the NordPool financial market which allow market participants to hedge against any exposure to market volatility.

(b) Allocation of capacity products

The NordREG congestion management guidelines require that no restrictions for access to interconnection between the four countries should be set in situations where there is no congestion, and therefore there is no need for a permanent allocation procedure (such as auctions) for access rights to a cross-border transmission service in the Nordel area. In situations where cross-border congestion does arise, the allocation of transmission capacity occurs on a day ahead basis through implicit auctions in the NordPool Elspot market.

In the past, explicit auctions allocated capacity on the interconnection between Denmark (Jutland) and Germany. However, sine 2005 this has been replaced by an implicit auction process which effectively links the German and NordPool electricity markets and, in principle, allows any NordPool participant to access the German electricity market.

(c) Preferential rights of access to the transmission grid

Under the system of feed-in-tariff used in Denmark all eligible renewable projects are automatically guaranteed grid access and a certain price for the electricity that they produce. In addition, in times of constraint on the network, renewable energy is given preferential access over non-renewable generation. As discussed above, grid operators are obligated to purchase this electricity and Energinet.dk estimates that the costs associated with its public service obligations – including providing priority access for renewable – accounts for about half of transmission costs.

2. Germany

(a) The nature of capacity products

All new connections to the German grid are granted firm transmission rights. Historically, this has meant that rights to connect to the transmission grid would only be allocated where there was sufficient network capacity and, accordingly, expansion by a TSO might, in some cases, need to occur prior to allocating rights. In light of concerns that the TSO's (who are still largely vertically integrated) could use this policy to deny access to the grid to new forms of generation,[27] the new Act relating to the connection of new power plants (*Netzanschlussverordnung- KraftNAV*) requires TSOs to ordinarily accept all additional connection requests to the grid and allocate firm access rights, even if the necessary grid extension or reinforcement measures are not in place. Under this Act, it is expected that the TSO will employ the standard congestion management approach if congestion arises of re-

[27] Federal Network Agency 'National contribution to the EU benchmarking report' 2006, page 14 <http://www.ceereu.org/portal/page/portal/ERGEG_HOME/ERGEG_DOCS/NATIONAL_REPORTS/2006/E06_NR_Germany-EN.pdf>

dispatch, including requiring certain generation sources to change their feed-in to the network.

(b) Allocation of capacity products

The introduction of the *Netzanschlussverordnung – KraftNAV* is intended to improve the ability of new power plants to obtain access to the grid, and one of its requirements is that new connections are entitled to privileged access rights to the grid for up to ten years after the first feed-in (and at the latest 2022). However, the Act specifies a limit that no more than half the available grid capacity can be allocated to privileged customers under this provision.

In respect of the allocation of rights for interconnector capacity, the general approach of the TSO's in Germany is to apply the procedures set out in EC regulation on the cross-border exchanges of electricity.[28] On all cross-border interconnections – with the exception of the Kontek cable between Germany and Denmark – capacity is allocated through coordinated explicit auctions. The available interconnection capacity auctioned is typically divided into a series of annual, monthly and daily auctions. Capacity rights that are sold on an annual or monthly basis may be subject to 'use it or lose it' provisions, which allows for any excess capacity to subsequently be sold in the daily auctions. According to the German TSOs, any revenues from the allocation of cross-border transmission capacity are taken into account in calculating the use of system charges.

(c) Preferential rights of access to the transmission grid

The Renewable Energy Sources Act of 2004 (*Erneuerbare-Energien-Gesetz EEG*) makes it compulsory for operators of power grids to give priority to feeding electricity from renewable energies into the grid, and, to pay generators a fixed price for their power under a feed-in-tariff arrangement. TSO's must give immediate priority to the connection of installations for the generation of electricity from renewable energies, and to purchase all the electricity available from these installations. This obligation applies to the TSO who is closest to the location of the generation installation. Critically, the TSO is required to connect renewable energy sources even if it requires the TSO to upgrade its grid at reasonable economic expense.

However, as discussed above, some TSO's in Germany have recently had to introduce 'generation management' measures to restrict the amount of renewable generation feeding-in to the system at particular times because of insufficient capacity on the transmission system. In addition, new renewable generators are being required to accept in their terms of connection that they may not have preferential access to the grid at all times.

E: Recovery of costs associated with system development

Article 7 of the EU Renewables Directive (2001/77/EC) requires Member States to establish a legal framework, or to require TSOs to set up and publish standard rules, relating to the

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[28] European Council and Parliament 'Regulation EC No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity' 26 June 2003
< http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2003:176:0001:0010:EN:PDF>

sharing of costs of system installations, such as grid connections and reinforcement, between all producers benefiting from them over a network.

The Directive provides that the 'sharing of costs' should explicitly take into account the benefits that accrue to those already connected to the transmission system, as well as benefits for TSOs and distribution companies as a result of improvements to the transmission system. The Directive also requires that transmission charges do not discriminate against those renewable energy sources produced in 'peripheral regions, such as island regions and regions of low population density'.[29]

1. Norway and Denmark

(a) Recovering costs associated with the construction of new transmission capacity

In Norway, new investments in the transmission system are financed in two ways. First, some of the costs associated with the new construction are recovered through the general tariff. Second, generators that connect to the network may be required to pay an investment contribution. The investment contribution is a one-off payment charged to those benefiting from the grid investment, and can be levied to cover the costs of connecting new customers to the network, or for the reinforcement of the network for existing customers.

Statnett calculates the investment contribution on the basis of the cost of connecting the customer to the network. If the connection also requires reinforcement in so-called radial joint networks, a pro rata share of these costs may be included in the investment contribution. Statnett has the discretion to allocate any investment contribution between customers connected at the time the installation is completed, and future customers connecting up to 10 years after completion of the installation. This is done either by incrementally costing the investment contribution when new customers are connected, or by requesting the contributions in advance and subsequently adjusting them on a proportional basis as more connections are made to the network.

In Denmark, new generators are required to pay only the 'shallow' connection costs associated with connecting the generator to the transmission or distribution grid. Any deeper reinforcement or expansion costs associated with the connections are funded by the TSO or the distribution company, and, therefore spread over all system users.[30]

This policy appears consistent with the nature of the development of wind farms in Denmark to date which has typically involved small-scale installations connecting to local distribution grids at distribution voltage levels. However, as the amount of wind power connected to the main transmission grid increases – particularly following the development of large scale offshore wind parks – the situation may be expected to change. According to some accounts, the growth in medium and large size wind farms has reached the point in Denmark where they have a major impact on the transmission system.[31] The IEA recently recommended that

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[29] Point 6 of Article 7 of 'Directive on Electricity Production from Renewable Energy Sources', 2001/77/EC, 27 September 2001 < http://eur-lex.europa.eu/pri/en/oj/dat/2001/l_283/l_28320011027en00330040.pdf>

[30] Statnett 'Technical regulations for the properties and the control of wind turbines' Annex 1, page 5, 19 May 2004.

[31] I M de Alegría et al 'Connection requirement for wind farms: A survey on technical requirements and regulation' Renewable and Sustainable Energy Reviews Volume 11, Issue 8, October 2007, page 1859

all new generators in Denmark, including wind power plants, should be made to pay their share of transmission upgrades.[32]

(b) Recovery of costs associated with use of transmission system

In general terms, the use of system tariffs throughout the Nordel grid are typically point-of-connection tariffs. A point-tariff is based on the charge at the grid user's point of connection with the network, so, for example, a generator that connects at a particular point pays the local connection charge for that point and can purchase electricity from anywhere in the Nordel region. Under this system a user only pays a transmission tariff to his local network company. Tariffs for feed-in to the grid (delivery) and drawing power from the grid (out-take) differ and depend on geographic location within the transmission grid.

The point tariffs used in Norway comprise three components: an energy charge, a capacity charge and a fixed charge. The fixed charge is generally common to all users on the network but, as discussed below, can be reduced by Statnett if the input is located in a favourable location on the network. The energy component varies by the amount of flow and is designed to cover marginal losses, and varies by season and time of day and is differentiated by point of connection on the grid. Finally, the capacity charge is related to transmission congestion and is calculated as the difference between the area price and the system price. Therefore the capacity charge is zonal in nature and will be positive for those generators connecting to the network in surplus areas.

Denmark's point tariffs also comprise three components: a grid component, a system component and a Public Service Obligation (PSO) component. The grid tariff is a fixed use of system charge and covers the costs associated with the major transmission grid, while the system tariff covers costs relating to reserve capacity, system operation and is variable in nature. The PSO tariff covers costs relating to public service obligations, including the cost of renewable energy, research and development. As discussed in more detail below, the PSO component, which is levied on all users, relates directly to the costs associated with renewable energy and is intended to allow renewable producers to be guaranteed a fixed price for supply. Energinet.dk tariffs for the first quarter of 2008 show the PSO component represented approximately 45% of the overall tariff.[33]

Denmark has a system of postage stamp charging meaning that charges are levied on all users irrespective of location. However, the charges do differ between the Western and Eastern parts of the Danish grid. In addition, these charges are primarily recovered from demand customers.

(c) Are transmission rates discounted for type of generation or location on grid?

Statnett is currently considering various measures and tariff schemes that reflect the costs associated with feeding-in power at different points on the network. The rationale is that those responsible for new production should bear a larger part of the costs of necessary investment in the grid, and that this will influence the decisions of electricity generators in

[32] International Energy Agency 'Energy Policies of IEA Countries – Denmark 2006 Review' June 2006 < http://www.iea.org/Textbase/press/pressdetail.asp?PRESS_REL_ID=181>

[33] Energinet.dk 'Electricity Tariffs for the first quarter of 2008' <http://www.energinet.dk/en/menu/Market/Tariffs+and+prices/Electricity+Transmission+tariffs/Electricity+-+Tariffs+ for+the+first+quarter+of+2008.htm>

their investment decisions as to where to locate on the grid.[34] As part of this process, Statnett has introduced a 'grid efficiency phasing-in tariff' which reduces the grid tariff for generators located within certain areas for a period of up to 15 years. To be eligible for the phasing-in tariff, new generators must be established in areas where it is documented that new generation will bring grid savings.

As discussed above, Denmark employs various subsidies to support specific forms of generation such as wind power. In particular, utilities have, over the years, been obliged to purchase renewable energy at fixed prices of between 70% and 85% of the retail price of electricity, an amount greater than the wholesale price for non-renewable generation. The costs associated with this subsidisation policy are recovered through the PTO component of the transmission access charge. In addition, it is claimed that most renewable energy sources are not required to pay transmission access charges, and those that do are eligible for an exemption for up to 10 years.

2. Germany

(a) Recovering costs associated with the construction of new transmission capacity

The Renewables Law requires that the grid extension costs associated with connecting renewable energy to the grid are the responsibility of the TSO and can be recovered through the grid fee levied on all users. The costs borne by the generator are therefore shallow, limited to those associated with connecting to the main grid, while the TSO bears the costs associated with any 'deeper' expansion or reinforcement of the network. More generally, the recent Act on the Connection of New Power Plants, designed to encourage more generation development in Germany, stipulates that any 'other facilitation costs' incurred by the TSO during set up of the grid connection can no longer be imposed on new connections (such as costs associated with transformers or a switchgear bay at the point of connection).

Under the Infrastructure Planning Acceleration Act the TSO's are also responsible for covering a proportion of the 'shallow' costs associated with extending the transmission line offshore to connect to proposed offshore wind parks. The costs of the grid connection will initially be borne by the TSO in the region, but will ultimately be distributed across all four TSOs in Germany. These costs are expected to be substantial both for the onshore and offshore networks (estimates of necessary extensions to the onshore transmission grid to connect to offshore wind parks in Schleswig-Holstein are 70 million euros and in Niedersaschen 120 million).[35]

(b) Recovery of costs associated with use of transmission system

The tariffs for use of the transmission system in Germany levied by the four TSO's typically comprise three elements which reflect the costs associated with the use of the grid infrastructure, costs relating to system and balancing services, and costs that reflect losses that occur in transmission. As in Denmark, these charges are levied on demand customers and are zonal in nature, however, these charges can vary within the area controlled by a particular

[34] Statnett 'Grid Development Plan 2005-2020', June 2005, page 12
< http://www.statnett.no/Resources/Filer/Dokumenter/Div.%202005/Nettutvikling_Engelsk_trykk.pdf>
[35] E.ON Netz 'Windpower integration into the transmission system' Presentation by Wilhelm Winter IEA workshop May 2004 < http://www.iea.org/Textbase/work/2004/nea/winter.pdf>

TSO. For example, E.ON Netz has defined three sets of prices for different zones that it controls.[36]

In response to the growing costs associated with managing the increasing amount of renewable energy on the system (so-called 'EEG enhancement') the BnetzA is currently examining the impacts of these costs, and whether they should be identified as a separate surcharge to the transmission network charge.[37] Presently these costs – estimated at several hundred million euros per year by the TSO – form part of the use of system charges. Given that considerably more electricity is generated from wind power in northern Germany than in the south a system of equalisation is used to share the burden of these costs across all four TSO's.

(c) Are transmission rates discounted for type of generation or location on grid?

As in Denmark, TSO's in Germany are obliged to purchase renewable energy sources produced in their control area as a priority. In addition, the TSO's are required to pay fixed rates for the purchase of the electricity under various versions of the German Renewables Law (*Stromeinspeisungsgesetz für Erneuerbare Energien*).[38]

Renewable generators are required to be paid a fixed tariff for up to a 20-year period. The exact tariff paid is, however, differentiated according to the energy source, the size of the installation, the date of commissioning, and in the case of wind whether it is located onshore or offshore (onshore wind parks are paid a fixed fee for the first five years which is then reduced).

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[36] E.ON Netz 'Prices for grid utilisation' 2008
< http://www.eon-netz.com/frameset_reloader_homepage.phtml?top=Ressources/frame_head_eng.jsp&bottom= frameset_english/net_eng/net_eng_bottom.jsp>

[37] Federal Network Agency 'National contribution to the EU benchmarking report' 2007, page 10
<http://www.ceer-eu.org/portal/page/portal/ERGEG_HOME/ERGEG_DOCS/NATIONAL_REPORTS/National%20Reporting%202007/E07_NR_Germany-EN.doc>

[38] Some of the German TSO's (who are vertically integrated) have challenged the legal basis of these arrangements which they claim conflict with EU state aid rules. In a decision in 2000, the European Court of Justice concluded that such arrangements were not in breach of the EC Treaty.

- 3 -

APPROACHES IN NORTH AMERICA

A: Background and Renewable Energy Targets

There are no binding targets for renewable energy at the federal level in the United States or Canada, but a number of states/provinces have set their own targets for increasing their share of renewable energy. In the United States, twenty-four states and the District of Columbia have established binding 'renewable portfolio standard' (RPS) policies.[39] These policies require electricity providers in each state to procure a minimum percentage of power from renewable energy resources. In total, these states account for more than half of the electricity sales in the United States.

At the federal level, the Federal Energy Regulatory Commission (FERC) has undertaken to improve the non-discriminatory terms of access to transmission lines for all generators, including renewable energy sources. In particular, recently introduced FERC rule 890 exempts intermittent power generators, such as wind power plants, from excessive 'imbalance' charges. This rule also requires transmission operators to offer a 'conditional firm' service which allows generators to provide a firm service for most, but not all, of the hours in the requested time period. This change is seen to be of particular benefit to wind generators.

The regulatory landscape in the United States involves a combination of state and federal regulatory oversight. In general terms, the FERC is responsible for approving the rates and transmission investments undertaken or commissioned by regional system operators. However, state regulatory agencies also play a role in the siting and approval of transmission expansions (other than in areas designated National Interest Electricity Transmission Corridors under the federal Energy Policy Act 2005).

The concept of the 'Independent System Operator' (ISO) is an important one in North America. ISO's are typically not-for-profit independent entities that do <u>not</u> own any transmission infrastructure and are responsible for ensuring non-discriminatory access to the transmission systems in particular areas. Over time, the responsibilities of some of the larger ISOs – such as the CAISO in California and ERCOT in Texas – have expanded to include a pro-active role in identifying, coordinating and planning the necessary development of transmission infrastructure and reinforcements within their region.

1. California

The renewable energy targets in California are related to its Renewable Portfolio Standard (RPS) policy. Specifically, the targets are for 20% of consumption being served by renewable

[39] The RPS targets for the different states can be viewed at:
<http://www.eere.energy.gov/states/maps/renewable_portfolio_states. cfm?print>

resources by 2010, rising to 33% by 2020. According to estimates published by the CAISO, this will require an additional 7,319 MW of renewable generation coming onto the grid (of which 4,577 MW is expected to be wind).

To achieve these targets, the California government has established a Renewable Energy Transmission Initiative (RETI). RETI is a joint project led by the California Energy Commission (CEC), California Public Utilities Commission (CPUC), the California Independent System Operator (CAISO) and publicly owned utilities.[40] The purpose of RETI is to identify the transmission projects that are needed to accommodate renewable energy goals, support future energy policy, and facilitate transmission corridor designation and transmission and generation siting and permitting. The RETI programme is divided into three phases. Phase 1 screens and ranks potential renewable resource zones and broadly identifies transmission requirements in these zones. Phase 2 develops conceptual transmission plans to the highest-ranking zones. Phase 3 is intended to support transmission owners in developing detailed plans of service for commercially viable transmission projects and to establish the basis for regulatory approvals of specific transmission projects. The draft report of Phase 1 of the Initiative was published in March 2008.[41]

There are three main transmission network owners in California: Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric. The system operation functions are performed by the CAISO which is responsible for ensuring non-discriminatory access to the transmission grid and also operates three separate competitive markets for electricity, including a transmission capacity market, an ancillary services market and a real-time imbalance market. The CAISO is regulated by the FERC which periodically approves its tariff for providing these services.

As is the case in other jurisdictions, under-investment in the transmission network has been a major problem identified in California in recent years, and the CAISO has identified at least seven specific high voltage transmission projects needed to increase reliability and the efficient use of the network.

2. Texas

Texas is the leading producer of wind power in North America. In late 2007, it was estimated that some 4,525 MW of wind generation was operating in Texas, and that an additional 3,600 MW of wind power was under interconnection agreements.

Like California, Texas has a RPS policy. Its RPS targets are expressed in terms of additional renewable generation rather than as a percentage of consumption. The specific targets in Texas are that 2,000 MW of new renewable energy capacity be provided by 2009, 5,800 MW by 2015 and 10,000 MW be added by 2025.[42] It is estimated that some $1 billion investment in new and upgraded transmission will be required to support these targets.

The setting of these targets has been accompanied by a range of policies and legislative acts.

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[40] Further information can be obtained at: <http://www.energy.ca.gov/reti/index.html>

[41] RETI Stakeholder Steering Committee ‘Renewable Energy Transmission Initiative Phase 1A’ (draft report) March 2008< http://www.energy.ca.gov/2008publications/RETI-1000-2008-001/RETI-1000-2008-001-D.PDF>

[42] Texas State Energy Conservation Office ‘Texas Renewable Portfolio Standard’ < http://www.seco.cpa.state.tx.us/re_rps-portfolio. htm>

Senate Bill 20 focuses on the future development of large transmission lines to accommodate renewable energy, including in remote regions.[43] This Act requires that Competitive Renewable Energy Zones (CREZ) be identified and designated in advance of connection requests. Texas has also introduced a renewable energy credit program which is administered by one of the ISOs (ERCOT).

A number of different companies own transmission network infrastructure in Texas, including: TXU; CenterPoint Energy; and AEP Texas Central Company; Entergy Corp.; Exel Energy; and AEP Southwestern Electric Power Co.

The Electricity Reliability Council of Texas (ERCOT) is the ISO responsible for managing and operating the majority of the transmission network, controlling an estimated 85% of the electricity load in Texas. As with the CAISO, ERCOT does not own any transmission infrastructure but is responsible for the identification and review of potential areas of transmission improvement. There are currently some $2.8 billion in new transmission projects underway in the ERCOT region, in part in response to the development of renewable energy projects.

The ERCOT electricity grid is self-contained and is not synchronously interconnected to the rest of the United States. As a consequence of this, ERCOT is not subject to regulatory oversight by the FERC. Rather, its rates and activities are regulated by the Public Utility Commission of Texas (PUCT). However, other non-ERCOT regions such as the South West Power Pool – the second biggest ISO in Texas – are regulated by the FERC.

3. Alberta

Similar to the United States, the renewable energy targets and policies in Canada have been set by the provinces rather than federally. The approach in Alberta is not to set a specific target for renewable energy, but rather to focus on removing barriers and implementing appropriate incentives for the connection of renewable and alternative energy sources.

The government of Alberta have eschewed broad or long term targets on the basis that they see these as arbitrary and because they impose a top-down approach based on limited information. The preferred approach in Alberta is to dissect the problem into 'manageable wedges'. One of these wedges involves examining the challenges faced by small producers in accessing the electricity grid. [44]

Alberta's adaptation of its transmission network in response to increasing wind power production will involve an expansion of the grid into new areas of the province. The majority of generation is located in the central and northern part of the province, while the identified areas of greatest wind expansion are located primarily in south and south-east of the province. Some 4% of total installed capacity in the province is currently wind, and a further 1600 MW of wind energy projects are currently awaiting the required transmission upgrades.

[43] Texas Senate Bill 20, 'An Act relating to this state 's goal for renewable energy', 2005
< http://www.capitol.state.tx.us/tlodocs/791/billtext/pdf/SB00020F.pdf>
[44]Alberta, Department of Environment ' Alberta's 2008 Climate Change Strategy' January 2008-01-27
< http://www.environment.alberta.ca/documents/Climate_Change_Strategy_2008.pdf>

There are two main transmission facility owners that form part of the Alberta Interconnected Electric System: ATCO Electric and EPCOR Utilities. There are limited interconnections between the Alberta electric system and those of the neighboring provinces of British Columbia and Saskatchewan.

The ISO in Alberta is the Alberta Electric System Operator (AESO), an independent not-for-profit entity, which is responsible for the planning and operation of the Alberta Interconnected Electric System (AIES). AESO contracts with transmission facility owners to acquire transmission services, procure ancillary services and manage the settlement of the wholesale and transmission system services markets .

Until recently, the Alberta Energy and Utilities Board (EUB) has been responsible for regulatory oversight of the transmission network. However, since January 2008 a new organization – the Alberta Utilities Commission (AUC) – has become responsible for approving the tariffs for transmission and distribution companies, as well as the AESO tariff.

Insufficient transmission investment is a current issue in Alberta. AESO reports no significant upgrade of the network since 1980. As a result, it has planned an upgrade of network over the next ten years at an estimated cost of $1.5 billion CAD.

B: Transmission planning process

1. Federal Policy in the United States

(a) Systems Planning and Consents

Approval for the expansion of the transmission network in the United States must typically be obtained from state authorities. In most cases, this responsibility rests with the state energy agency or regulatory agency, although some states have a multiple agency process. However, the federal government can be directly involved, and does otherwise influence the transmission system planning process. For example, FERC rule 890 sets out nine principles that a transmission owner or ISO must comply with in planning the transmission network,[45] and requires that the planning process be detailed in the tariff filing. The Energy Policy Act of 2005 also directs the FERC to develop incentive based rates for transmission networks.[46] These include a range of incentive based measures designed to 'bolster investment' in transmission infrastructure, such as 'incentive rates' of return on equity for new investment.[47] In addition, expansion may be in an area that has been designated as National Interest Electricity Transmission Corridors under the Energy Policy Act 2005. The designation of such corridors is undertaken by the U.S Department of Energy, and permission for transmission lines to be sited within National Corridors is within the domain of the FERC.

[45] These are: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation. FERC Order 890 Fact sheet, page 3 < http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf>

[46] Section 219 of the Energy Power Act (2005) < http://www.doi.gov/iepa/EnergyPolicyActof2005.pdf>

[47] The other measures introduced are listed on the FERC website. <http://www.ferc.gov/industries/electric/indus-act/trans-invest.asp>

In a recent Order (March 2008), the FERC expressed concern about growing 'interconnection queues' that are developing in many regions, noting that one effect of such queues are delays in interconnecting renewable generation which in turn created substantial challenges for some States in meeting their renewable portfolio targets. [48]

(b) Assessment criteria employed: deterministic, cost-benefit and reliability

In many parts of the U.S., transmission planning has typically involved the assessment and approval by an ISO and relevant regulator of any investment plans presented by a TO as and when they arise and in accordance with fairly narrow deterministic criteria. However, a number of states have recently moved away from this 'passive' approach and empowered ISOs with greater responsibilities in respect of system development requiring them to identify areas for expansion and to undertake and perform the necessary cost/benefit studies *ex officio*.

In addition, FERC rule 890 has made economic planning considerations a mandatory element to be considered in the transmission planning assessment process, requiring that planning studies examine not only reliability upgrades but economic upgrades as well. [49] Reliability standards across the United States and Canada are set by the North American Electricity Reliability Corporation (NERC).[50] Critically, NERC does not specify criterion for reliability in network design, rather it sets out the standards for operation under various conditions and the allowed response.

2. California

(a) Systems Planning and Consents

The responsibility for transmission system development in California is principally undertaken by the Independent System Operator, CAISO. The CAISO conducts the transmission planning process on an annual cycle which includes an 'open season', the purpose of which is to provide stakeholders with the opportunity to propose transmission projects, study requests or otherwise submit relevant data.[51]

The California Public Utilities Commission (CPUC) is required to issue a 'certificate of public convenience and necessity' for all new transmission lines. An application for certification with CPUC must first be approved by CAISO, and some areas of analysis are duplicated in these two approval processes.

The CPUC adopts a 'two-track' process in its assessment of applications: an environmental assessment and an assessment according to the California Public Utilities code. The CPUC has the power to approve both the design and route for the transmission line proposed by the

[48] Federal Energy Regulatory Commission 'Order on Interconnection Queuing Practices' [Docket No. AD08-2-000] March 20, 2008 <http://www.ferc.gov/whats-new/comm-meet/2008/032008/E-27.pdf>
[49] Federal Energy Regulatory Commission 'Order No. 890 Final Rule: Preventing Undue Discrimination and Preference in Transmission Service' Fact Sheet, page 3 <http://www.ferc.gov/industries/electric/indus-act/oatt-reform /order-890/fact-sheet.pdf>
[50] Background on the evolution and scope of these standards can be found at: <ftp://www.nerc.com/pub/sys/all_updl/standards/StandardsBackground.pdf>
[51] CAISO, Revised (No. 3) Draft Business Practice Manual for the Transmission Planning Process 12-Nov-2007, page 23 < http://www.caiso.com/1c95/1c95a6f38ea0.pdf>

utility; adopt a different design or route for the line; or deny permission to build the line. In assessing applications, the CPUC must take account of a set of specific criteria/factors as set out in the Utilities Code.[52] In particular, as part of the environmental assessment, the Commission staff is required to undertake a detailed environmental impact study. In addition, local governments and communities affected by proposed developments have the opportunity to participate in the regulatory proceedings.

In September 2007, a ‘streamlined’ mechanism for the permitting of transmission lines was proposed. Under the proposal, the California Energy Commission would be empowered to designate transmission corridor zones for the development of future high voltage electric transmission lines in California, either on its own motion or by application. Through this process of identifying and validating proposed transmission corridors – which will require the potential environmental impacts and alternatives to be evaluated during the designation process – it is intended that the subsequent permitting for those projects will be streamlined for applicants seeking a permit to build a transmission line within a designated corridor.[53]

(b) Assessment criteria employed: deterministic, cost-benefit and reliability

The adoption of renewable policies in California (such as the RPS) has changed the transmission planning and permitting environment. Prior to the RPS legislation transmission planning and permitting was principally focused on system reliability issues. However, economic and environmental considerations are increasingly becoming relevant in the assessment of proposed expansions, and the CPUC now considers “system reliability, renewable and economic benefits” in the transmission permitting process.[54]

The approach adopted by the CAISO to system planning has shifted in recent years from a reactive or deterministic planning process to a more proactive approach. In the past, the CAISO relied almost exclusively on the TO’s expansion plans, with its role limited to approving those plans. Since 2006/07 a more proactive approach is adopted whereby the CAISO annually prepares its own transmission plan aimed at identifying transmission projects necessary to mitigate congestion on the transmission network. Under this new approach, CAISO identifies the investments that need to be made, and the TO’s react to the CAISO’s proposals. Critically, when it comes to developing a proposal, TO’s are given a right of first refusal to build the CAISO project, and if the TO declines the CAISO will put the proposal out to tender for third party investors.

CAISOs approach to identifying necessary investments explicitly involves a cost-benefit analysis. Of interest is that this approach incorporates the broader benefits associated with any investment. Under its ‘Transmission Economic Assessment Methodology’ (TEAM) the CAISO assesses a range of societal, consumer, producer and transmission benefits in its consideration of economic assessments of network expansions or enhancements.[55] In general

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[52] California Public Utilities Code, Section 1002

[53] California Energy Commission, ‘Initial Statement of Reasons for Adoption Of Regulations Governing Designation of Transmission Corridor Zones’, Title 20, Division 2, California Energy Commission Docket No. 07-OIR-01, 11 September 2007 < http://www.energy.ca.gov/sb1059/documents/2007-12-05_meeting/2007-09-12_STATEMENT_OF_REASONS.PDF>

[54] California Public Utilities Commission, ‘CPUC Regulatory Requirements for RETI’, Presentation at stakeholder steering committee, October 29, 2007. <http://www.energy.ca.gov/reti/meetings/2007-10-29_meeting/presentations/BONE-REGULATORY_REQ_2007-10-29.PDF>

[55] CAISO ‘Transmission Economic Assessment Methodology’ June 2004 <http://www.caiso.com/docs/2004/06/03/2004060313241622985.pdf>

terms, this approach is viewed as making the approvals process for transmission investments easier.

3. Texas

(a) Systems Planning and Consents

As in California, the planning process for the development of the transmission system in Texas is ISO-led, and in particular by ERCOT, who, together with the other major Texas ISOs perform coordinated planning studies on a periodic basis. The identification of expansion or reinforcement projects are not, however, limited to ERCOT and any market participant or transmission owner can propose projects.

The process is broadly similar to California in that ERCOT staff undertake an independent review in the first instance of any proposals received, this includes providing the public with an opportunity to comment on proposals. However, the Public Utility Commission of Texas (PUCT) is responsible for the ultimate approval of any transmission upgrades, and as in California, must issue a certificate of convenience and necessity prior to any work being undertaken.

A 2005 law allows for the designation of special 'Competitive Renewable Energy Zones' (CREZ) within the state.[56] A principal purpose of the zones is to ensure that the planning process precedes the expected development of renewable energy facilities. In addition, the Act aims to shorten the process for the issuing of a certificate of convenience and necessity to 180 days, and replaces the need for signed interconnect agreements prior to work being undertaken with financial commitments.[57] Finally, the Act deems any transmission built in these zones to meet RPS as 'used and useful', and therefore allows for the costs to be recovered.

The PUCT is charged with identifying CREZ and will cooperate with ERCOT, who will conduct the necessary studies and make the submissions to the PUCT.[58] To be designated as a CREZ the area must have suitable renewable resources and offer cost-effective transmission solutions. In addition, there must be evidence of sufficient developer commitment. The process of designation of CREZ occurs through biannual contested case proceedings heard by the PUCT in which ERCOT makes submissions. In 2006, ERCOT identified 25 areas of preliminary interest in CREZ, and in July 2007 eight CREZ's were selected and transmission plans were developed for the works required to accommodate wind capacity in the range of between 10,000 MW and 25,000 MW. The final approval orders on these CREZ are expected in March 2008.

A concern that has arisen in the process of the development of the CREZ policy is that it may encourage 'piling on'. This refers to a situation where multiple generators move to sites where they know transmission will eventually be constructed, essentially 'piling on' in areas

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[56]'Renewable Portfolio Standard, Texas Senate Bill 20, July 2005
< http://www.capitol.state.tx.us/BillLookup/Text.aspx?LegSess=791&Bill=SB20>

[57] Prior to this, major transmission extensions were not approved by ERCOT or the PUCT until the Interconnection Agreements had been signed and deposits have been made by wind farm developers.

[58]Public Utility Commission of Texas '§25.174. Competitive Renewable Energy Zones' 1 April 2007
<http://www.puc.state.tx.us/rules/subrules/electric/25.174/25.174.pdf>

that have been financially secured by the first developers.[59] This behavior can detract from the incentives of being the first mover, particularly as the last generators to arrive will typically be further out on the system than the early movers, and more likely to be allowed to produce energy than early movers (who would be closer in and with higher shift factors) in times of congestion.

Various proposals have been examined to address this issue including financial and physical solutions. Among these: a 'latecomer tax'; the use of a virtual offer curve which gives priority dispatch to specific generators; the introduction of a mandatory special protection scheme for early movers; and limitations on the amount of generation allowed to interconnect on a specific line. Although this issue is still being examined, the PUCT has an existing ability under CREZ rules to 'limit interconnection', to 'establish dispatch priorities regarding the transmission system in the CREZ, and to identify the developers whose projects may interconnect to the transmission system in the CREZ under special protection schemes'.[60]

(b) Assessment criteria employed: deterministic, cost-benefit and reliability

The transmission system planning process undertaken by ERCOT includes an explicit consideration of the costs and benefits of all transmission proposals. In addition, in assessing potential improvements to the network, ERCOT allows for system improvements which could be solved through re-dispatch of generation, but are being proposed because they are likely to result in a net economic benefit to the market based on ERCOT-wide impacts. To assess these system-wide impacts ERCOT has developed a market simulation model (UPlan) to predict which transmission lines are likely to cause congestion in the future, and to then estimate the likely costs savings that might result from transmission system improvements to relieve that congestion.[61]

The PUCT is authorised to require the construction of facilities which reduce congestion on the transmission system. Specifically, the PUCT can require TO's to 'construct or enlarge transmission facilities' to improve reliability, including through the reduction of transmission constraints in a 'cost-effective' manner. As part of this process, applicants are required to submit a comprehensive cost-benefit analysis which includes demonstrating that the cost of the transmission project is lower than the cost of other congestion management techniques such as dispatch.[62]

[59] Public Utility Commission of Texas 'Renewables and Transmission Task Force Report to WMS', May 15, 2007, page 3 < http://www.puc.state.tx.us/rules/rulemake/34577/RTTF_Report_to_WMS.pdf>

[60] Public Utility Regulatory Act Rule 25.174 (e) 'Disincentives for excess development in a CREZ' < http://www.puc.state.tx.us/rules/subrules/electric/25.174/25.174.pdf>

[61] It is reported that over the past two years ERCOT have used UPlan to assess the costs and benefits of an estimated $500 million of transmission projects.

[62] Public Utility Commission of Texas 'Transmission Planning, Licensing and Cost-Recovery Rulemaking: Proposal for Publication of new §25.199' October 2004 <www.puc.state.tx.us/rules/subrules/electric/25.199/28884pub.doc>

4. Alberta

(a) Systems Planning and Consents

The Alberta system operator (AESO) is responsible for the planning of transmission expansions, and undertakes periodic transmission development plans toward this end, including 10 year and 20 year plans and specific studies.[63]

All planned changes or new investments in transmission infrastructure must be approved by the Alberta Energy and Utilities Board prior to them being undertaken (this role is now presumably undertaken by its successor the AUC). In considering an application, it is necessary that prior approval of the project from local authorities on land use and right-of-way authorization and on environmental matters from Alberta Environment be obtained, and that any local, landowner and land-issues are resolved. The EUB has placed strict time limits on the review and approval process, and decisions as to the siting and permit of licence must be made within six months of receipt of application.

In preparing its applications, AESO must detail generator 'milestones' that will trigger the necessary transmission construction to ensure that the commitments received from generators prior to actual construction accord with the risk associated with transmission expansions. The approach of AESO in respect of transmission planning is proactive in nature and designed to precede the growth in generation development. The Electric Utilities Act (2003), requires AESO to plan the network according to particular needs, which under current policy involves the 'elimination' of all congestion on the transmission network.[64]

Wind generators must follow and comply with the various stages of the interconnection planning process described above. However, until recently there was a threshold of 900 MW applied to the connection of wind generators to the transmission system to address concerns regarding system reliability. This threshold has recently been lifted, and new requirements are heavily focused on establishing reasonable forecasting and capability standards for wind generators.[65]

(b) Assessment criteria employed: deterministic, cost-benefit and reliability

The transmission planning and assessment criteria in Alberta are unique among the jurisdictions examined in this report. As noted above, the transmission system in Alberta is required to be planned so as to be "sufficiently robust so that 100% of the time, transmission of all anticipated in-merit electric energy… can occur when all transmission elements are in service, and is adequate so that, on an annual basis, and at least 95% of the time, transmission

[63] Alberta Regulation 86/2007 'Transmission Regulation' section 8-10. This was not always the case and in the past any participant was allowed to compete for the development, ownership and operation of transmission infrastructure under the 'request for proposals' process (an approach which appears similar to CAISO's new tendering process). However, in implementation this process was found to create delays in the development of transmission additions, which impacted on reliability. Alberta has since abandoned this process, and returned to an approach where projects are assigned to the regulated TO's.

[64] Government of Alberta 'Electric Utilities Act' Chapter E-5.1, 2003 <http://www.eub.gov.ab.ca/BBS/requirements/actsregs/eu_act.pdf>

[65] As part of their interconnection and operating requirements wind power facilities will be required to forecast their output for the next day as well as two hours prior to the start of delivery.AESO, 'Market and Operational Framework for Wind Integration in Alberta' 7 March 2007, page 4 < http://www.aeso.ca/files/Wind_Framework_7March07.pdf>

of all anticipated in-merit electric energy…can occur when operating under abnormal conditions".[66] In assessing proposals for system development, a principal criteria for assessment by AESO is therefore whether the proposal will achieve the result of 'congestion free' transmission.

C: Approach to congestion on the transmission system

In the jurisdictions examined in North America the independent system operator is responsible for addressing and managing any congestion on the transmission network.

Under the encouragement of the FERC, a number of electricity markets in the United States have implemented – or are in the process of moving toward – a nodal pricing system which involves some form of locational marginal pricing (LMP) for electricity.[67] This pricing approach allows for different prices to be set at each generation node which reflect both the costs associated with the generation of power, and the relative congestion at that point of the network. In addition, the adoption of locational marginal pricing for electricity – such as those being adopted in California and Texas – may, in principle, usefully signal to system planners and transmission investors the value of new or incremental transmission capacity at different parts of the transmission system, as reflected in the difference in prices between specific nodes.

1. California

(a) General approach to congestion on the network

The CAISO uses a zonal approach to congestion management that divides the state into a number of zones, and then models the expected congestion on the major paths between these zones. Specifically, after receiving the scheduled day-ahead generation forecasts, the CAISO assesses the impact on the transmission system across the state. In the event that congestion is likely to emerge along certain paths, the CAISO will accept so-called 'adjustment bids' from schedulers on a day-ahead and hour-ahead basis in a congestion management market. The CAISO then pays the net amount of congestion residue revenues that it collects to holders of firm transmission rights. Should congestion not be sufficiently resolved in the congestion management market, a charge is levied on scheduling coordinators that continue to input generation on those paths that are heavily constrained.

As part of its Market Redesign and Technology Update (MRTU) due to be fully implemented in 2008, the CAISO is moving toward a congestion approach based on the use of a combination of LMP and congestion revenue rights (CRR). This approach will employ the signals from LMP to manage congestion via a re-dispatch process which reduces the amount of electricity from nodes on the so-called 'source' side of a constraint, while simultaneously increasing the amount of electricity from nodes on the 'sink' side of a constraint. The

[66] Alberta regulation 86/2007 'Transmission Regulation' section 15 (1e).
[67] See for example the transmission pricing reforms discussed in: Federal Energy Regulatory Commission 'Notice of proposed rulemaking on Standard Electricity Market Design' Docket No. RM01-12-000, July 2002 (subsequently withdrawn in July 2005). See also: Federal Energy Regulatory Commission 'Long-Term Firm Transmission Rights in Organized Electricity Markets' 18 CFR Part 42 (Docket No. RM06-8-001; Order No. 681-A) November 2006 <http://www.ferc.gov/whats-new/comm-meet/111606/E-1.pdf>

congestion cost for the transmission from the 'source' to any 'sink' on the transmission system will be the difference between the locational marginal prices at the source and sink nodes.

(b) How the decision to build versus manage constraints is resolved

The CAISO systematically examines the various alternatives to the identified transmission projects when it receives a request for a transmission planning project. Specifically as part of the planning process, it undertakes both an economic planning and congestion study.[68] These studies are intended to compare the advantages of new transmission build against other congestion management measures. This process is undertaken in three stages: first, areas of significant and recurring congestion are identified; second, in those areas where congestion is identified, a detailed study is undertaken; and finally an evaluation of congestion mitigation alternatives is developed.

In response to the potential increase in renewable energy, the CAISO has recently approved the development of large-scale specific transmission projects across the state, including the proposed \$1.8 billion transmission link with the 'wind-rich' Tehachapi area.[69]

2. Texas

(a) General approach to congestion on the network

ERCOT classifies congestion as either 'zonal' congestion or 'local' congestion. Zonal congestion involves managing congestion on so-called commercially significant constraints (CSC). In 2006, there were six CSC's in the ERCOT area, and five separate congestion zones. Costs associated with managing congestion in these zones are assigned to each quantity serving entity based on their relative impact on the constraint. As discussed below, exposure to zonal congestion costs can be hedged through the purchase of Transmission Congestion Rights. Currently all costs associated with local congestion within the five zones is 'uplifted' and spread across all market participants in that zone on a pro-rata basis according to load share.

In part, because of the high costs associated with managing congestion on the network in this way, ERCOT is moving toward a nodal system of electricity pricing to be introduced in 2009. This approach will involve a nodal market based on central dispatch and locational marginal prices where all energy and ancillary services will be acquired in a single auction run by ERCOT.

(b) How the decision to build versus manage constraints is resolved

In the ERCOT area applications for transmission developments must include a comprehensive cost benefit analysis. This analysis must show that the proposed cost of the

[68] CAISO, Revised (No. 3) Draft Business Practice Manual for the Transmission Planning Process 12 November 2007, section 4.2 < http://www.caiso.com/1c95/1c95a6f38ea0.pdf>
[69] CAISO 'California ISO Board Approves Tehachapi Transmission Project', News Release, January 2007 <http://www.caiso.com/1b70/1b70eeda42890.pdf>

transmission project is expected to be lower than the cost associated with other congestion management techniques such as re-dispatch.[70]

ERCOT reports a much greater expansion of transmission infrastructure in its region than anywhere else in North America, with nearly $2 billion invested in transmission infrastructure facilities and the construction of 700 miles of new transmission lines since 1996.[71] Many of these projects were planned and built directly to relieve constraints that had emerged on the network. Despite these additions, the significant growth in new generation, particularly wind generation, has meant that inadequate transmission capacity is in place in certain areas, for example, in the McCamey area in West Texas.

3. Alberta

(a) General approach to congestion on the network

The periods of congestion on the transmission system in Alberta are limited given AESO's requirement to ensure that the network is congestion free under normal operations. Should congestion arise in real-time, AESO manages that congestion through merit-order dispatch, and, if necessary, by pro-rata curtailment of different generators. Where generators are paid out of merit to alleviate a transmission constraint, these costs form part of the transmission network costs and are not reflected as an uplift component in energy prices.[72]

(b) How the decision to build versus manage constraints is resolved

The AESO is responsible for 'eliminating' congestion on the transmission system and as such the primary approach to dealing with long term expected increases in generation connections would appear to be the construction of new infrastructure. However, as is the case in Germany, it is recognised that in the medium term, while necessary transmission capacity is being approved and constructed, growth in renewable generation may result in additional congestion on the network.

The approach in Alberta is to define the costs associated with managing the integration of greater levels of wind generation onto the transmission system as 'costs of the transmission system'. This is similar to the proposed connect- and manage approach with socialised costs currently being considered in the U.K. However, this approach also puts requirements on wind generators to install power management technology and to develop necessary procedures for wind forecasting, and therefore be able to comply with an instruction from the system operator to limit its output.[73] In situations where the transmission system cannot accommodate the forecasted or actual wind power generated, AESO will re-dispatch or limit wind power to maintain system integrity.

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[70] Public Utility Regulatory Act Rule 25.199 (h) Transmission Planning, Licensing and Cost-Recovery for Utilities within the Electric Reliability Council of Texas.
< http://www.puc.state.tx.us/rules/subrules/electric/25.199/25.199.pdf>

[71] ERCOT 'Transmission Expansion in ERCOT: Project No. 28500: Activities Related to the Implementation of a Nodal Market For the Electric Reliability Council of Texas' July 12, 2005
< www.ercot.com/news/presentations/2005/Expansion_in_ERCOT.pdf>

[72] Government of Alberta 'Transmission Regulation' Regulation 174/2004, section 8(5) and 23
< http://www.qp.gov.ab.ca/documents/Regs/2007_086.cfm?frm_isbn=9780779724192>

[73] AESO, 'Market and Operational Framework for Wind Integration in Alberta' 7 March 2007 page 9-10
< http://www.aeso.ca/files/Wind_Framework_7March07.pdf>

D: The nature and allocation of capacity products

The FERCs rule on Long-Term Firm Transmission Rights (Rule 861-A) requires all transmission customers to have the ability to access certain standardised transmission rights, allowing for some degree of regional flexibility. This rule was issued in response to long-standing concerns about undue discrimination in terms of access and rights to use the transmission system in the various states.[74]

In addition, FERC rule 890 requires transmission or system operators to offer a ‘conditional firm’ component as part of their long-term point-to-point service. The rule addresses the problem of generators being denied the use of firm transmission rights because they are unable to supply for even a short period within a defined service period. In offering a conditional-firm component the transmission provider must identify either a defined set of system conditions, or annual number of hours, during which the service will be conditional and to allow customers to select one of them. This is seen as being particularly beneficial to renewable energy sources such as wind generation.

FERC rule 890 also introduced reforms intended to promote greater consistency with transmission planning and construction timelines.[75] The rule revised the rollover provisions in the pro-forma open access transmission tariff to extend the on-going rights for transmission customers to renew or ‘rollover’ their contracts from a minimum duration of one year to a minimum term of five years. In addition, a transmission customer must provide notice of whether or not it will exercise its right of first refusal to roll-over the contract, no less than one year prior to the expiration date of the transmission service agreement (previously the notice requirement was 60 days).

In terms of allocation methods, the FERC rule on long-term firm transmission rights states that the initial allocation of rights shall not require recipients to participate in an auction, and that rights can be re-assigned to other entities. The rule requires that the long-term firm transmission rights must be made available with term lengths (and/or rights to renewal) that are sufficient to meet the needs of load serving entities to satisfy their obligations, and that transmission organizations may propose rules specifying the length of terms and use of renewal rights to provide long-term coverage, but must be able to offer firm coverage for at least a 10 year period.[76]

[74] Federal Energy Regulatory Commission ‘Long-Term Firm Transmission Rights in Organized Electricity Markets’ 18 CFR Part 42 (Docket No. RM06-8-001; Order No. 681-A) November 16, 2006 <http://www.ferc.gov/whats-new/comm-meet/111606/E-1.pdf>

[75] Federal Energy Regulatory Commission ‘Preventing Undue Discrimination and Preference in Transmission Service’ Order 890 16 February 2007, page 61 <http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf>

[76] Federal Energy Regulatory Commission ‘Long-Term Firm Transmission Rights in Organized Electricity Markets’ 18 CFR Part 42 (Docket No. RM06-8-001; Order No. 681-A) November 16, 2006, pages 10-11 <http://www.ferc.gov/whats-new/comm-meet/111606/E-1.pdf>

1. California

(a) The nature of capacity products

There are various categories of capacity products for the use of the transmission service that are used by the CAISO to manage the system.[77] However the CAISO typically offers new users firm transmission rights to access the transmission system on a ‘first come, first served’ basis. These are contractual rights that have both a scheduling and financial aspect and which entitle the holder to access the transmission grid and to receive a portion of the usage charges received by the CAISO from the transportation of energy. Each firm transmission right is defined by a transmission path from an originating zone to a contiguous receiving zone. As discussed above, as part of the implementation of the Market Redesign and Technology Update (MRTU) firm transmission rights will be replaced with Congestion Revenue Rights (CRR) and the LMP pricing of energy.[78] These congestion revenue rights are financial in nature and entitle the holder to recover a portion of the congestion rents collected by the CAISO in managing the network.

(b) Allocation of capacity products

The CAISO currently allocates firm transmission rights on the basis of an annual auction or by purchasing financial transmission rights in a secondary market. The auctions typically commence approximately two months before the actual term of the financial transmission right and any entity is able to participate in this auction process, or purchase rights in the secondary market. As part of the CAISO’s market re-design, this process will be replaced by the introduction of short-term and long-term congestion revenue rights (CRR). Short-term CRR’s will be allocated for a period of one year, while the long-term CRR will be ten years. As noted above, and consistent with FERC guidelines, each CRR product will have a specific ‘source’, ‘sink’ and MW quantity attached to it.

The CAISO will allocate the CRR free of charge to transmission customers within the CAISO grid area according to their expected annual congestion charges. Likewise, the CAISO will allocate CRR to companies that invest in new transmission facilities.[79] After conducting these allocations, the CRR will be sold in auctions conducted by the CAISO. The products sold will be differentiated by season and time of use (on-peak or off peak) and will be sold in annual or monthly auctions.[80]

[77] The four categories are as follows: (a) transmission capacity that must be reserved for firm Existing Rights; (b) transmission capacity that may be allocated for use as ISO transmission service (i.e., “new firm uses”); (c) transmission capacity that may be allocated by the ISO for conditional firm Existing Rights; and (d) transmission capacity that may remain for any other uses, such as non-firm Existing Rights for which the responsible PTO has no discretion over whether or not to provide such non-firm service. See CAISO Tariff, section 16.2.4D

[78] Further information on this process is available at: <http://www.caiso.com/clientserv/ftr/index.html>

[79] CAISO ‘Congestion Revenue Rights’ <http://www.caiso.com/docs/2005/02/22/2005022208470027987.pdf>

[80] CAISO Proposal: Long Term Congestion Revenue Rights 05-Jan-2007
< http://www.caiso.com/1b5d/1b5dd6af4fef0.pdf>

2. Texas

(a) The nature of capacity products

ERCOT currently offers two forms of zonal 'flowgate rights' for six designated points on its network. In general terms, flowgate transmission rights are a financial hedging instrument that allows the holder of the right to collect payments on the basis of a 'shadow price' associated with a particular transmission constraint. The rationale in defining 'flowgates' is to link the financial payments with the underlying flows of electricity on the system. The two types of flowgate rights currently available in Texas are Transmission Congestion Rights (TCRs) and Pre-assigned Congestion Rights (PCRs). TCRs relate to specific directional commercially significant constraints (CSC) for a particular hour. PCRs are directly assigned to municipally owned entities and electric cooperatives which own or have a long-term (greater than five years) contractual commitment for annual capacity which was entered into prior to 1 September 1999.

In general terms, the value of flowgate rights in the ERCOT area is calculated by determining the market-clearing zonal energy price in each area, which then yields a 'shadow price' of congestion that is equal to the difference between the marginal costs of generation between areas. Currently, ERCOT's does not estimate a 'shadow price' for intrazonal congestion.
Partly to address the issue of increasing intrazonal congestion, the ERCOT market is in the process of changing from a zonal to a nodal system of pricing, and this has implications for the capacity products available. The ERCOT market will become a nodal market in 2009 at which point the current flowgate rights will be replaced with more specific Congestion Revenue Rights that will apply between different settlement points (that coincide with injection and withdrawal points), rather than be based on pre-defined constraints.

(b) Allocation of capacity products

The allocation of transmission capacity rights currently occurs in two ways. Pre-assigned Congestion Rights are directly allocated to particular entities which own or have long-term commitments which pre-date September 1999. Transmission Congestion Rights (TCRs) are allocated according to an auction process. Forty percent of total annual quantity of TCR's (less those pre-assigned) for a given commercially sensitive constraint are allocated to an initial annual auction for each hour of the year. In addition, ERCOT conducts monthly auctions of the total expected quantity of TCRs available for that month based upon forecasted conditions. Both TCRs and PCRs can be traded in any secondary market, subject to a limitation on any entity directly or indirectly having access to the revenue from more than 25% of total available TCRs/PCR's at a single constraint interface.

E: Recovery of costs associated with system development

The FERC's current interconnection pricing policy is to allocate the costs of the new facilities on a 'first come, first served' basis. New generators connecting to the network incur the 'shallow' costs associated with interconnection, and initially pay for any 'deeper' network upgrades. However, these 'deep' costs are then refunded in the form of transmission credits (with interest) on the system bill over a five to twenty year period, the result being that the costs of the network upgrades are ultimately rolled into the prices paid by all transmission customers. Critically, in its 2003 proposal for a Standardization of Small Generator Interconnection Agreements and Procedures, the FERC proposed to treat both large generators and small generating facilities in the same way in respect of this charging policy.[81]

However, in response to concerns about growing 'interconnection queues' various revisions to these policies are being considered.[82] In a recent Order, FERC has required Regional Transmission Organizations and ISOs under its jurisdiction to file a report outlining the status of their efforts to improve the processing of their interconnection queues.[83] The Order notes that the unprecedented demand in some regions for renewable generation, in particular, has placed stress on existing queue management procedures. In addition, it observed that delays in interconnecting renewable generation in the Midwest Independent Transmission System Operator and CAISO regions are creating substantial challenges related to meeting the renewable portfolio standards in those States.

FERC's preference is for each region to develop solutions tailored to its specific circumstances. However, it is open to considering a range of possible variations with regard to future and early-stage existing interconnection requests. First, it is considering increasing the amount of the deposits required at the different stages of the process. Second the Commission is considering changes to the process for applications to reduce processing times, such as eliminating the requirement for a separate feasibility study. Finally, the Order notes that moving from a 'first-come, first-served' approach to a 'first-ready, first-served' may be merited in some circumstances.

1. California

(a) Recovering costs associated with the construction of new transmission capacity

In California, as elsewhere in the United States, the approach toward the recovery of the costs associated with new investment is to require new connections to incur both the 'shallow' and some proportion of the 'deep' costs associated with any network reinforcements. In general terms, this can act as a strong disincentive for renewable generators to be the first to connect to the network in a particular region as they will incur the all of the costs associated with any network upgrades.

To address this issue the CAISO recently proposed a separate category of transmission cost recovery for network investment which is directed specifically at renewable energy. The approach known as the Location Constrained Resource Interconnection Facility (LCRIF) requires that the transmission operator finance the up-front costs of construction associated

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81 Federal Energy Regulatory Commission 'Standardization of Small Generator Interconnection Agreements and Procedures' 18 CFR Part 35 [Docket No. RM02-12-000] 24 July 2003< http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=9746256> See also: Federal Energy Regulatory Commission 'Standardization of Generator Interconnection Agreements and Procedures' 18 CFR Part 35 [Docket No. RM02-1-000; Order No.2003] 24 July 2003 <http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=9746398>

82 Federal Energy Regulatory Commission 'Order on Interconnection Queuing Practices' [Docket No. AD08-2-000] March 20, 2008 <http://www.ferc.gov/whats-new/comm-meet/2008/032008/E-27.pdf>

83 The report must describe the current size of the RTO's or ISO's interconnection queue (i.e. number of pending interconnection requests and total megawatts represented by those requests), the current projected timeframes for processing pending interconnection requests, and the nature and extent of any problems that have led to any such queue backlogs, including a discussion of how clustering has or has not alleviated those problems.

with the expansion of the transmission network.[84] The transmission operator then recovers these costs over time in the following way. Initially, on completion of the facilities, the unsubscribed portion is rolled into the transmission access charge and collected across all network transmission users. However, as generation resources develop in the area, and more connections are made to the LCRIF, the costs associated with its development are transferred on a going-forward and pro-rata basis to those new generation owners, and the costs included in the transmission access charge are correspondingly reduced. Once the anticipated generation is fully connected and the capacity of the LCRIF is fully subscribed, the forward cost of the project will be borne entirely by generation developers and will no longer be included in the transmission access charge.

(b) Recovery of costs associated with use of transmission system

The FERC approves the transmission tariffs set by the regional and independent system operators within its jurisdiction. Therefore the the access charges that the CAISO can charge for use of its system is determined through its tariff filing to the FERC. [85] The two categories of charge in the CAISO tariff are: the transmission access charge (TAC) and a wheeling access charge (WAC). The TAC is levied on all users of the CAISO transmission network.[86] The WAC is a charge levied on scheduling coordinators for wheeling, which seems to reflect the costs associated with system operation.[87] The CAISO's TAC rate is in the process of evolving from three separate TAC rates across the state (licence plates) to a single rate (postage stamp) over a ten year period from 2001.

2. Texas

(a) Recovering costs associated with the construction of new transmission capacity

In general terms, generation facilities that want to connect to the ERCOT grid are required to pay only the shallow costs associated with their connection, and not the 'deep' costs associated with upgrading the transmission system.

In areas designated as CREZ any costs associated with the development of infrastructure necessary to allow for the connection of significant renewable energy resources to the transmission grid is levied on all users of the grid through the transmission access charge.

[84] See the following documents on the CAISO's Location Constrained Resource Interconnection Policy <http://www.caiso.com/1816/1816d22953ec0.html>. In particular, see the most recent proposed draft tariff document: <http://www.caiso.com/1c7b/1c7bdff6635c0.doc>

[85] CAISO 'Combined Simplified and Reorganized Tariff as of November 19, 2007' <http://www.caiso.com/1c9b/1c9bd9f837a10.pdf>

[86] Details are set forth in Section 26 of the CAISO Tariff and Appendix F, schedule 3

[87] For example, this includes the use of the CAISO controlled grid for transmission of energy from a generating unit located within the CAISO controlled grid to serve a load located outside the transmission and distribution system of a transmission operator. On the other hand, a Wheel Through is the use of the CAISO controlled grid for the transmission of energy from a resource located outside the CAISO controlled grid to serve a load located outside the transmission and distribution system of a transmission operator. Further details are in Section 26 of the CAISO Tariff and Appendix N, part F.

(b) Recovery of costs associated with use of transmission system

ERCOT's tariffs are filed with the Public Utility Commission of Texas and are based on postage stamp transmission charges under Texas law.[88]

3. Alberta

(a) Recovering costs associated with the construction of new transmission capacity

Generators connecting to the grid are required to make a financial commitment and contribution towards any transmission system upgrades associated with their connection, called 'system contribution payments'. The purpose of these contributions is that they act as a long-term siting signal for generators as to where to locate on the grid, and they are intended to recover both a portion of local system costs and deep system costs.

The amount of system contribution payments each generator pays varies according to a number of factors, such the size of the proposed connection and its location on the system. The estimation of these costs must be cost reflective, but are not required to be based on the specific costs associated with upgrading the system. Depending on the nature of the proposed connection, the system contribution payment can be required to be paid up-front, or alternatively paid over time.[89]

However, any system contribution payment made by a generator is refunded over 10 years (subject to satisfactory operation by the generator), the refund amount being rolled into the rates paid by all load customers. Only generators who fail to operate above a minimum capacity factor – which may vary by technology (such as wind) – are not able to obtain a refund. It is argued that this approach will provide generators with the appropriate incentives to operate (to receive their contribution payment back), and that they will therefore be indifferent to how AESO plans and configures the transmission system, eliminating any 'race to be last' or free rider issues.

(b) Recovery of costs associated with use of transmission system

Transmission costs are recovered on a broadly averaged basis by AESO using postage stamp pricing. This means that distributors are charged the same tariff for transmission service no matter their location or generating source across the province.

[88] Public Utility Commission of Texas 'Substantive rules: Chapter 25' PURA 35.004
< http://www.puc.state.tx.us/rules/rulemake/21080/21080arc/091699pr.doc.>

[89] Alberta Department of Energy, Electricity Business Unit 'Transmission Development Policy Paper', November 2003, page 11-12 <http://www.energy.gov.ab.ca/Electricity/pdfs/transmissionPolicy.pdf>