A REVIEW OF TENNET'S CONNECTIONS POLICY

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Executive Summary

TenneT has asked The Brattle Group to study the existing Dutch policy for connecting and disconnecting generators, and to develop proposals for reform. TenneT has received a high number of requests for new connections, and the new demand currently exceeds network capacity. The unusual level of connection requests and the subsequent congestion has prompted Members of the Dutch Parliament to express concerns to the Ministry of Economic Affairs. The Ministry of Economic Affairs has recently responded to the Parliament, and NMa/DTe has written to TenneT requesting a review of the connection policy, which would consider the possibility of strategic behaviour by generators, the desire to promote a favourable investment climate, and the goals of transparency, non-discrimination and confidentiality.

During the course of our study, TenneT organised two workshops for interested parties to express their views on the existing connection policy and discuss proposed reforms to the policy; participants were also invited to submit written comments. We have incorporated suggestions and comments from these workshops in this report. Four participants gave permission to make their submissions public, which we include in Appendix IX.

Our review revealed that several important aspects of the existing connection policy enjoy strong support among generators: participants in the workshop expressed support for both the 'runback' scenario (where TenneT addresses congestion in part by connecting new generators on an interruptible basis if necessary to preserve network integrity) and the "first-come/first-served" system for responding to requests.

However, our review has also identified several concerns. The potential for strategic behaviour would include artificial despatch to create congestion that deters the construction of new power stations by rivals, hoarding sites by submitting an excessive number of applications for new connections, or delaying plant retirement specifically to prolong congestion.

Some aspects of the existing policy are not conducive to a favourable investment climate. The strategic behaviour described above can harm the investment climate. The law imposes risk on TenneT, requiring it to accept all connection requests without assurances that the DTe would adjust the tariffs to include the costs of the associated reinforcements. The only locational signal the current system provides is the waiting time for new connections in certain areas – this may not suffice to steer generator investment towards areas where it would reduce network expansion costs.

We consider international experience with connection policy, to derive ideas for reform. We have researched policies in the United States, the United Kingdom, Norway and Germany. We have identified eleven possible changes to connection policy, each of which draws inspiration from one or more country. Even if some reforms have not been implemented elsewhere, they have been debated actively. We divide the possible measures into three categories:

- Facilitating market transactions, through such means as auctions or publishing additional information that can facilitate decisions by generators.

- Changing the payments made by generators, such as the introduction of transmission charges, and the provision of locational signals.

- Reforms concerning the Transmission System Operator's response to new connection requests, or to investment in the network.

Figure 1 illustrates the different types of reforms considered.

Figure 1: Summary of policies analysed

Facilitate Market

Forced site auctions ✗ Threat of illiquidity ✗ Easily evaded	Tradable rights ✓ Efficient retirement ✓ But with limits	Time-limit to connections ✗ Hard to set limit ✗ Doesn't solve problems
Auction available capacity ✗ Market power abuse	Publish more information ✓ Available capacity ✓ Length of Queue	Use-it-or-lose-it policy ✗ Hard to apply ✗ Doesn't solve problems

Generator Payments

Deep charges ✗ Market too small ✗ Harsh on renewables	Up-front payments ↑ ✓ Add milestones ✓ Deter frivolous applications	
Bring back G charges ✓ Locational signals possible ✗ International distortions		

TSO Decisions

Just say YES: all firm ✗ Re-dispatch nightmare ✗ Market power problems	Start saying NO ✓ Reject costly locations	Licensing ✗ Does not solve the right problem
Say YES to small units ✗ Doesn't solve problems	Advanced planning/building ✓ Reduce lead time ✓ Efficient for renewables ✗ TSO risk	

In the main text of this report we discuss each potential reform, describing where it has been used or debated, and how it relates to the goals of the review: deterring strategic behaviour, improving the investment climate, and respecting the principles of transparency, confidentiality and non-discrimination. We then assess the likelihood of success and the potential problems that could arise, concluding with a recommendation. For some of the reforms, the recommendation involves an amendment to the way it has been implemented or proposed elsewhere. In summary, the process is to describe the reform, explain its basis in international experience, assess its appropriateness for the Netherlands, and to derive recommendations including possible amendments.

Core policy recommendations

Our first recommendation is to retain several important aspects of the existing connection policy: the "first-come/first-served" system for responding to requests, and the use of "run-back" scenarios. The first-come/first-served policy has defects, but is superior to the various alternatives that we consider, such as auctioning connection capacity, having a regulator select its favourite projects, or asking the TSO to honour all connection requests while addressing congestion through re-despatch. First-come/first-served has the merit of triggering a competition among generators to come forward with plans for new capacity if they fear congestion. First-come/first-served has the advantage of treating all applicants equally. TenneT's existing policy as a whole is not discriminatory. We do not recommend any changes that would require TenneT or DTe to favour particular types of generating capacity.

Below we also offer some recommendations for change.

1) Increase Transparency – TenneT can facilitate the market by publishing more information: the length of the queue and the amount of available connection capacity at different locations in the Netherlands. This information would guide the planning decisions of generators, improving transparency and the investment climate. TenneT can also promote "tradable rights" in a limited manner. Existing connections have no finite duration. The connection is a "right" of access to the grid, which already under existing legislation can be traded. A generator hoping to build a new power station could buy an old site from an existing generator who seeks to retire a plant. The existing connection would extend to the new owner. TenneT could facilitate this type of "trading the right", simply by disclosing to applicants whether the retirement of particular power stations could free up the connection capacity necessary to accommodate new ones. By "tradable rights" we do not intend any change to the first-come/first-served approach of TenneT to new connections. We simply refer to the publication of additional information of interest.

2) Implement Milestones with cancellation fees – TenneT can also change its existing connection contract without requiring new legislation. We contemplate the imposition of deadlines for the achievement of certain milestones with respect to site permits and construction. Failure to meet milestones would sacrifice the generator's position in the first come/first serve queue, allowing others to proceed.

TenneT should also face milestones. TenneT should volunteer to reduce the connection fee by a given amount if it fails to meet targets. The DTe should also offer TenneT financial rewards for consistent compliance with milestones.

We have considered but ultimately rejected raising the up-front payments that generators must make in congested areas. However, we support the idea of cancellation fees based on 'deeper' costs, if a generator withdraws a project but there is no one else to willing to locate at the abandoned location. Generators should contribute toward any wasteful deep costs they create from a connection application that they cancel subsequently. The UK has recently implemented a similar policy, where cancellation fees are higher in congested areas of the grid, and therefore relate to 'deep' reinforcement costs.

3) Permit in advance - Existing legislation would allow TenneT to start the permit process for network expansion in congested areas, prior to receiving applications for new capacity. Advanced permitting would reduce the time needed to expand connection capacity, facilitating the investment climate. The key to this reform is confidence that the DTe would approve the recovery of the associated costs in the transmission tariffs, although we understand that these costs are relatively minor. A more extreme version of this policy would include the commencement of network expansion before the receipt of requests for the associated connection capacity. However, such an approach would entail far more expenditures than merely securing permits. If TenneT expands the network in advance, it could face significant risks of building capacity that subsequently proves unnecessary. It could be risky for TenneT to adopt such a policy. The Dutch Government's targets for renewables could justify advanced network construction, but TenneT should only build in advance if the Government changes legislation and takes the initiative to guarantee the recovery of the associated costs. Other countries are implementing specific policies to anticipate investment in renewables.

Review of existing connection policy

Dutch law currently requires TenneT to accommodate all connection applications on a first-come/first-served basis. If the network does not have sufficient capacity to accommodate a request, then TenneT can at most delay offering the connection until completing the reinforcements that are necessary to maintain grid integrity. At the workshops TenneT organised to discuss the connection policy, participants (who represented generators) expressed support for the current first-come/first-served policy.

Generators pay a one-off 'shallow' connection charge for the new connection between their facility and the network, and a relatively small ongoing maintenance charge.[1] The connection charges do not depend on the location of the connection or the congestion of the network. Generators do not pay annual transmission charges ("G" charges). If a generator cancels a connection agreement with TenneT, it is liable for the shallow connection costs that TenneT has incurred, which can be several million Euros.

Requesting a connection at a particular site automatically precludes other generators from making requests at the same site for at least six months. After signing a connection agreement, a generator faces no deadline to complete the construction of a power station at the site. There is no limit on the number of simultaneous connection requests that a generator can make. If a generator is unsure about the location of a new power station, the generator can request connections at several different sites. Nor is a generator limited to requesting an amount of connection capacity that matches the size of the power station contemplated.

To cope with the recent high level of connection requests, TenneT has implemented a short-term solution (a 'runback scenario') offering connections that are interruptible until the completion of the re-enforcements necessary to preserve network integrity. The run-back policy accelerates plant construction, and deters generators from locating new power stations in constrained areas where the connections would be interruptible. At the workshops participants expressed support for the runback policy.

TenneT only offers one 'run-back scenario' to one generator at a particular site. If two generators apply at the same site, and sufficient capacity is not available, the first applicant may receive an offer of a run-back scenario but the second will not. The run-back scenario offered to a

[1] Approximately €12500 per year for 2007 on the 380kV/220kV network.

generator will specify the amount of capacity that is "firm" and the amount that is interruptible. An applicant for the connection can modify its plans if it wishes, and build a unit small enough to run entirely on a firm basis.

TenneT deals with day-to-day network congestion through re-despatch. Power stations offer TenneT a price to reduce output to relieve transmission constraints in one part of the grid, and reserve plant in another part of the grid offer a price to increase their production to make up the shortfall.

Other aspects of Dutch connection policy include:

- Lack of co-ordination between the connection policy and the tariff policy. Under the law TenneT must agree to connections, committing to network reinforcements before knowing whether DTe will allow TenneT to recover the associated capital expenditures in the tariffs.
- No ability to reinforce the network in anticipation of future connection requests. DTe asks TenneT to justify its planned reinforcements by reference to actual connection requests.
- While TenneT produces a capacity plan, it does not currently publish the available connection capacity at different sites.

We have reviewed the existing policy with respect to the following goals: preventing strategic behaviour, fostering a positive investment climate, promoting transparency and non-discrimination, and protecting confidentiality:

Preventing Strategic Behaviour

- *The possibility of hoarding capacity*. –generators could find it profitable to deter construction by rival generators, by placing artificial requests for connections despite the lack of any intent to build a power station. For the generator, a connection agreement can be an inexpensive option for use at a later date if the market develops favourably. However, holding the option does have a cost for society and other generators, possibly delaying the construction connection of more efficient plant, and projects that have a higher chance of success. Similarly, the current policy does not dissuade generators from mothballing old units.
- *Incentives for gaming:* If one generator knows that its rival has an interruptible connection, an incentive could arise to despatch power stations deliberately to create the congestion that prevents the rival from operating. Gaming incentives are of particular concern because interruptible connections are awarded to new power stations, which tend to be among the most efficient power stations on the system, and therefore pose more of a threat to rivals.
- *Insufficient incentives to retire plant*: The absence of G charges and of tradable connection rights provides little incentive for existing inefficient plant to retire and make connection capacity available for new plant. Existing generators could have financial incentives to mothball plant to deny new connection capacity to entrants.

Promoting a Favourable Investment Climate:

- *Risk:* TenneT faces a risk created by the obligation to accept connection requests before knowing whether the regulator will allow TenneT to recover the costs of the associated network reinforcements.

- *Inability to Anticipate Congestion:* DTe currently asks TenneT to justify network reinforcements by reference to customer connection requests. The network planning procedures do not explicitly consider the possibility of building in advance of requests, to avoid congestion. If the process only follows requests, then the system can have an extended congestion problem.

- *Lack of locational signals:* A favourable investment climate is one where both TenneT and the generators have signals to invest in an efficient manner. The existing policy incentivizes generators to issue a rush of connection requests whenever they perceive that there may be a scarcity of connection capacity. Currently, the only locational signal is the prospect that connections in congested areas of the country will be interruptible for a certain period of time. Otherwise, generators can raise network costs by requesting connections in congested locations, without having to bear the economic consequences. The absence of locational signals also deprives TenneT useful guidance concerning the areas to prioritize investment. If TenneT faces requests to connect in two different areas, and does not have enough resources to reinforce the network in each area simultaneously, it will not have clear guidance concerning the location of priorities.

- *Effects of strategic behaviour:* The strategic behaviour described above can have adverse consequences for the investment climate, because strategic behaviour poses a particular problem for new investment.

- *Lack of transparency:* As we discuss below, providing greater transparency could improve the investment climate for new generators.

Transparency, Confidentiality and Non-Discrimination

- *Transparency:* We have received a confidential letter from someone who recently applied for connection capacity in the Netherlands. The applicant was placed in a queue under the first-come/first-served policy. However, the applicant was not able to obtain information concerning:

  - its position in the queue,
  - the amount of capacity already requested by people who were ahead in the queue, or
  - whether sufficient capacity was available to honour the requests by the others in the queue as well as the applicant. TenneT asked the applicant to complete a study designing the connection, which would cost approximately €60,000, before TenneT would indicate the likely availability of capacity.

TenneT has verified the statements by the applicant. Providing the type of information requested would improve transparency. There is no reason to withhold the type of information requested until the completion of a study. TenneT agrees.

The current policy also lacks transparency concerning the capacity available to accommodate the construction of power stations at different available sites. TenneT does not publish any map that would indicate where in the Netherlands the greatest amount of connection capacity is available, or the locations of the congested sites.

- *Confidentiality:* The applicant who wrote the letter was told that concerns over confidentiality prevented TenneT from disclosing information concerning the length of the queue, the number of applicants, and the amount of capacity requested. We do not see why this information should raise concerns over confidentiality.
- *Non-discrimination:* TenneT's current policy does not treat any applicant differently. However, the broadest interpretation of the word "discrimination" includes the failure to recognize the differential impact that a uniform policy can have upon particular applicants. We do not offer any view on the legal interpretation of "discrimination". However, for the sake of analytical rigor we anticipate complaints from developers of power from renewable sources. Developers could argue that the current connection policy better suits the needs of large new turbines that use fossil fuels. Three factors arguably distinguish renewables from the perspective of transmission planning: their small size, shorter lead times for their construction, and the predictability concerning future investment. If the government is committed to its targets for the expansion of renewables, then TenneT can anticipate the amount of investment in renewable capacity more easily than it can forecast the construction of combined-cycle gas turbines. If these claims are true, then renewables arguably suffer disproportionately from a connection policy that takes a long time, that waits for connection requests before expanding transmission capacity, and that applies a "first-come/first-serve" rule. If the "first come" is one large project that the grid cannot accommodate, then its developer might wait in the queue for capacity and prompt the TSO to postpone the acceptance of subsequent applications from smaller projects that the grid *could* accommodate immediately. We consider these concerns when evaluating alternative connection policies below.

Alternative Connection Policies

Facilitating Market Transactions

Reforms could focus on market transactions. The TSO could reject the first-come/first-served approach to accepting connection requests, instead auctioning available transmission capacity for sale to the highest bidder. The Government or regulator could require generators to auction off sites that contain old, inefficient power stations, to create room on the network for new entrants ("forced site auctions"). The "tradable rights" option could permit new investors to offer existing generators money to reduce congestion by closing their inefficient old power stations. Finally, the TSO can improve market decisions by publishing more information.

Auction Available Capacity

1. *International Precedent:* We do not know of any country that uses auctions to award connections. The United States, the United Kingdom, Germany and the Netherlands all follow a first-come/first-served policy. However, the Netherlands and other countries already use auctions to sell interconnector capacity. The Netherlands has used auctions to allocate third-generation (3G) spectrum in the telecommunications sector, and National Grid allocates gas entry capacity via auction in the United Kingdom. The closest example of an auction for connection capacity has been in Ireland, where the regulator used an auction process to grant a licence for a new power station. The regulator had concerns that the small size of the Irish market and the concentration of generation capacity would deter new entrants. The regulator decided to offer the entrant some support in the form of a long-term contract for power, but the regulator solicited bids to see which developer would insist on selling the minimum portion of its capacity to a long-term contract. The goal was to select the developer who was willing to take most exposure to market prices, which would intensify competition. Although the Irish situation was different, in principle TenneT could use auctions to sell scarce connection capacity, replacing the current "first-come/first-served" policy.

2. *Goals of the Policy:* When discussing discrimination, we mentioned a concern that renewables could suffer disproportionately from a first-come/first-served policy if the "first come" was a project for a large power station that would create congestion. Under the existing policy, TenneT would offer the large power station a "run-back" scenario, and the large power station project would obtain priority over subsequent applicants. TenneT would not accept subsequent applications until the completion of the reinforcements prompted by the large power station, even if the subsequent applicants had smaller projects that the grid could immediately handle. An auction would permit everyone interested in a particular area to bid simultaneously for the available capacity. Perhaps the developer of the large power station in this example would submit a lower bid, reflecting the risk of interruption under a run-back scenario. We might expect the highest bids to come from the developers with smaller projects who could anticipate having 100% firm connections.

3. *Assessment:* Auctioning connection capacity would not satisfy the goal of preventing strategic behaviour. Market power often motivates strategic behaviour. Auctions do not work well in the presence of market power. Generators with market power would assign the greatest value to the auctioned sites, and would be able to out-bid new entrants. Auctions can work well for allocating telecom spectrum, because of the ability to ensure in an auction that there are more licenses available for sale than there are incumbents. The 3G auctions in several countries have assured new entry. Auctions for interconnector capacity or gas pipeline capacity can avoid market power concerns by placing limits on the portion of capacity that any one company can purchase. In the alternative of fixed limits, mechanisms such as use-it-or-lose-it rules can help prevent the exercise of market power after the auction, even if the auction for interconnector or pipeline capacity was not competitive. In contrast, we do not see

how to assure competitive auctions for connection capacity without creating serious problems. We explain in a separate section below that a "use-it-or-lose-it" approach would be difficult to implement with respect to connection capacity. In the absence of "use-it-or-lose-it" rules, policy makers would have to ensure that the auction itself is competitive, by for example auctioning off a number of connections and sites simultaneously, ensuring that the number of sites available was greater than the number of incumbent firms and applying a 'one-site, one-firm' rule to prevent incumbents from buying up sites intended for entrants. But such a policy would require the authorities to choose which sites would be auctioned. It seems unlikely that the Authorities would have better information than power plant developers about the best sites to develop. Moreover, the authorities would have to hold back some sites, until there were a sufficient number to auction in a block. But holding back sites could frustrate new plant development and act as a form of hoarding. The only alternative to auctioning a block would be to compel the sharing of connection capacity at an existing site among competing generators. The regulator or TenneT could allocate one site's connection capacity in lots to different bidders. We know of some cases where multiple generators own units at a common site, or have a joint venture for despatching a common unit. However, dividing a site into lots would either require or interfere with decisions concerning the number and types of units to build at a particular site, undermining a key goal of liberalization: to entrust such decisions to the market. The only other option would be to preclude incumbents from bidding for new sites. However, such a policy would be discriminatory in the absence of a serious demonstration of incumbent market power, and could risk serious inefficiency if incumbents are best placed to build new power stations due to their experience, efficiency or market knowledge. We cannot recommend such a policy in the absence of compelling evidence concerning the threat of market power abuse by incumbents.

Furthermore, at times the market will have sufficient generation capacity and there will be little interest in building new power stations, as was the case in the Netherlands a few years ago. At such moments, the auctions for available capacity might be extremely illiquid. The auctions would have to distinguish between the connection capacity available in different geographic areas. For some areas there may be few interested bidders. Auctions require liquid markets to function properly. The need for liquidity is another reason why some countries use auctions for interconnector capacity but not for connection capacity.

First-come/first-served has two positive features: it does not discriminate, and it motivates competition among generators to accelerate their investment plans. If generators fear a lack of connection capacity, they will have incentives to come forward with applications as soon as possible, given prospective market prices. Of course, the connection policy should entail adequate measures to ensure timely construction of the power stations after submission of the connection requests. If so, then a first-come/first-served policy will put pressure on developers to bring forward plans for new sites as soon as possible, instead of adopting a "wait and see" approach that could exaggerate the periods of scarcity in the investment cycle. Generators also expressed support for the first-come/first-served policy in the workshops.

4. *Recommendation:* we do not recommend auctioning connection capacity.

Forced Site Auctions

1. *International Precedent:* In the mid-90s, the electricity regulator of the United Kingdom documented the systematic abuse of market power by two large electricity generators. When the two dominant generators closed down power stations, suspicions arose that one motivation could be to induce an artificial scarcity of capacity, to raise electricity prices. The regulator investigated the issue, and considered the merits of forcing the dominant generators to auction off available sites to third parties prior to closing power stations. The regulator did not have the legal authority to impose such a commitment. However, the dominant generators agreed to explore the desirability of selling old power stations as opposed to closing them. They sought the views of consultants who prepared reports saying that it did not make sense to sell the particular power stations targeted for closure.

2. *Goals of the Policy:* Forced auctions would seek to improve the investment climate, by providing project developers access to existing sites that already have connections to the transmission system. Forced auctions would not address the types of strategic behaviour discussed in connection with our review of the existing policy, which relate to the despatch of existing power stations, requests for connection capacity and the refusal to close existing sites. The obligation to auction a site would only arise after a generator had already decided to retire the power station.

3. *Assessment:* A policy of forced auctions would confront several problems. First, a generator could undermine the effectiveness of the policy by mothballing power stations instead of closing them. By claiming that a particular power station would one day return to operation, a generator could postpone or avoid the requirement to auction the site.

   Second, by trying to improve the investment climate, a forced auction policy could unwittingly exacerbate the feared strategic behaviour of artificially postponing plant retirements.

   Fourth, forced auctions might not even improve the access of sites to independent project developers. As we mentioned above, concerns with strategic behaviour often presume the existence of market power. Auctions do not tend to work well in the presence of market power, and generators with market power would be able to out-bid new entrants. If strategic behaviour is a serious concern, it is difficult to see how forced auctions could solve anything.

   In theory, a heavy-handed policy of forced auctions could avoid the problems described above. The government could investigate and reject mothballing proposals that might evade the auction requirements. The government could insist on retiring units at a particular point in time, and could forbid anyone with market power from offering bids for auctioned sites. However, such an auction policy would present a serious risk of inefficient consequences such as premature plant retirement, and would compromise property rights significantly. Owners might be forced to sell sites at points in time when the market had very little interest in building new capacity, incurring artificial losses. Owners could have legitimate business reasons to retain sites and extract greater value from them at subsequent points in the business cycle. International best practice is to require a serious demonstration of market power abuse prior to compromising the property rights of private parties. In most countries, a dedicated competition authority or a court has the authority to investigate allegations of abuse and impose remedies, but the law could also grant DTe this authority.

4. *Recommendation:* We do not recommend forced site auctions as a general policy. We understand that the legal framework in the Netherlands would already permit competition authorities to impose forced auctions if they found a serious demonstration of market power abuse. We see no grounds to promote forced auctions to a general policy that would apply regardless of actual abuse.

Tradable Rights

1. *International precedent:* As we mentioned earlier, at present a connection is a "tradable" right because a generator can sell its site to a third party, and the connection right will transfer with the property. Connection rights in the Netherlands are indefinite—they do not have any fixed expiration date. We consider a policy of facilitating trades in connection rights, by disclosing to applicants whether the closure of particular existing sites could free up sufficient connection capacity to satisfy the request for a new connection. Conceivably, TenneT could sign a connection contract stipulating that the applicant's request would be honoured immediately upon the closure of a specific site. The applicant would then sign a contract with the owner of the relevant site, and offer payment in exchange for closure.

2. *Goals of the policy:* The policy would increase transparency, by giving people more information about the system. The additional transparency could help improve the investment climate, helping the developers of new projects to avoid the wait for reinforcements to the transmission system. Facilitating trades might also reduce the incidence of strategic delays to plant retirement. Even if a generator perceived an inappropriate value of €X from delaying plant retirement, conceivably the developer of a new project might find it worthwhile to pay the existing generator more than €X to retire the power station, ending the strategic behaviour.

3. *Assessment:* Networks are complex. The owner of a power station might not know whether or to what extent its retirement might free up capacity to connect a new power station somewhere else on the network of interest to developers. A TSO is in a unique position to know these things. Disclosing them would facilitate the operation of the market. It cannot threaten confidentiality to tell a developer that the closure of a

particular power station might free up the connection capacity necessary to honour the developer's request, instead of waiting ten years for reinforcements.

4. *Recommendation:* If the network does not have sufficient transmission capacity to honour the request for a new connection, TenneT should tell the applicant whether the retirement of a station or stations at particular points in the network would free up the necessary capacity. TenneT should be willing to sign connection agreements that make the grant of the request contingent on plant retirements occurring elsewhere.

Publish More Information

1. *International Precedent:* In the United States and the United Kingdom, TSOs publish information concerning the capacity available to connect new power stations. Applicants for new connection capacity can expect to receive information concerning their place in the queue and the likely availability of capacity. We understand that Elia (the Belgian TSO) has recently started publishing information on its website regarding connection capacity available at each substation.

2. *Goal of the Policy:* By publishing more information, TenneT would hope to improve transparency, which helps the investment climate.

3. *Assessment:* The only possible objections to increased publication would be the administrative costs, and concerns over confidentiality. The administrative costs of publication are small in relation to the likely impact. Having information about available capacity can help guide the developers of power stations to identify the best sites from a transmission planning perspective. Publishing information could even reduce TenneT's administrative costs, by deterring applications for new connection capacity in congested areas. We see no reason why the publication of information would compromise confidentiality. TenneT would not have to publish the names of the applicants for new connections. Concerns over confidentiality would also seem inconsistent with the common industry practice of announcing to the public the plans for new power stations.

4. *Recommendation:* TenneT should publish information concerning the amount of new connection capacity that remains available at different parts of the network (possibly on a substation by substation basis), and the amount of available capacity that has already been requested in particular locations. Applicants for new connections should know their position in the queue and the likely availability of capacity. TenneT could also identify those substations for which it would be very expensive to increase the capacity.

Use-it-or-lose-it policy

1. *International Precedent:* Use-it-or-lose-it (UIOLI) describes a policy of reviewing the despatch of power stations. If a generator does not despatch the power station sufficiently, the regulator would determine that the generator was hoarding its connection rights to the detriment of competition. The regulator would cancel or

reduce the generator's connection right. Competition law acknowledges that dominant generators can abuse the market by hoarding capacity. The courts in many countries would have the authority to require the divestiture of a connection right as a remedy to stop perceived abuse. However, we see two key distinctions between general competition policy and a formal UIOLI policy. First, to implement a UIOLI policy would not require a prior finding of market dominance, just a finding that the generator could not justify its low level of despatch. Second, the generator would not receive compensation for the loss of its connection right. General principles of competition law would support a forced auction as the way to prevent abuse while interfering the least amount necessary with the property rights of the generator. UIOLI policies apply to pipeline capacity in the natural gas industry, but we do not know of any country that applies a UIOLI policy to electricity connections.

2. *Goals of the Policy:* A UIOLI policy would seek to deter the strategic behaviour of hoarding connection rights to the detriment of competition.

3. *Assessment:* Some participants in the TenneT workshop of June 2007 expressed support for a UIOLI policy. However, we foresee severe difficulties in its implementation, similar to those confronting a forced auction policy. The efficient use of peak plant may entail extremely infrequent despatch. Any regulator may find it difficult to determine whether infrequent despatch was efficient or an exercise in hoarding. Errors by the regulator would risk closing efficient peak plant that the system needs. Generators may also mothball plant legitimately, in the hope of returning to service when electricity prices rise at a later date. This optionality is an important part of a plant's value, which a UIOLI connection policy could negate. Market participants discussed the option of applying this policy only to new power stations, to prevent adverse effects on existing generators who invested under a different regulatory regime. We like the principle of exempting existing power stations. However, applying the policy only to new connection agreements would postpone the effectiveness of the policy for somewhere between 20 and 30 years, when today's new plant is old and marginal.

4. *Recommendation:* We do not recommend applying a UIOLI connection policy.

Time limit to connection agreement

1. *International Precedent:* When a generator applies for a connection, TenneT could add an expiration date to the agreement, designed to match the anticipated useful life of the new power station. Neither the United Kingdom nor the US applies a time limit to generator connections.

   We understand that connection agreements in the gas industry have expiration dates. However, the (upstream) gas industry involves the exploitation of a finite resource – the gas field – and the oil company can make a reasonable estimate of how long the field will take to deplete. Moreover, the time it takes to deplete the field is to a large extent under the control of the oil company – it is therefore relatively common for host governments to stipulate that the field must be depleted within a certain time frame, to ensure timely tax and royalty revenues. In contrast, a power plant is a machine to turn fuel into electricity – it has no pre-defined useful lifetime. There is no analogous logic to insisting that a plant close after a set period of time. Therefore, the use of time-limited connection agreements in the gas industry is not a meaningful precedent for the electricity industry.

2. *Goals of the Policy:* Imposing expiration dates on connection agreements could help prevent hoarding capacity.

3. *Assessment:* Some participants in the June 2007 TenneT workshop suggested this policy. We are concerned that the policy could harm the investment climate. At times it can be efficient to invest in upgrading or modifying a power station. Time limited connection agreements could deter generators from making efficient investments that would prolong the life of a station. Perhaps the policy could permit a power station in the eighteenth year of its useful life to seek an extension of the connection agreement, contingent on undertaking an investment programme. Even so, we foresee difficulties deciding on the amount of the extension, and the amount of investment required to qualify for an extension. Excellent maintenance of a plant could extend its useful life, yet maintenance is not as tangible as an investment upgrade. If undertaking an investment becomes a requirement for extending a connection, then generators might undertake frivolous investments, or inefficiently reject the alternative of excellent maintenance in favour of an investment overhaul. Furthermore, unpredictable changes in market conditions could make it efficient to extend the lives of generating units without unusual maintenance or investment. If market prices are extremely high the year before a plant's scheduled retirement, then the generator may do best to tolerate the inefficiencies and higher likelihood of breakdown associated with its old unit, running it as much as possible for a few more years. Finally, to respect investor expectations we would recommend imposing expiration dates on new power stations only, exempting existing ones. Therefore, the proposed policy would not have any effect on the market for at least 20 years.

4. *Recommendation:* We do not recommend placing time limits on connection agreements.

Changing the Payments Made by Generators:

Dutch generators only pay "shallow" connection charges, defined as the costs of building the specific infrastructure necessary to connect them to the network. Paying "deep charges" would make generators responsible for the costs of reinforcing the network to accommodate specific connection requests. Such a policy could motivate generators to seek new connections in areas that minimize network reinforcement costs. Another option is to "bring back G-charges" with the hope of motivating generators to retire old units that might free up new capacity for efficient new entrants. A third type of reform could involve an increase in the "up-front" payments that generators make when requesting connections, and the imposition of deadlines for progressing with the construction of the associated power station.

Deep Charges

1. *International Precedent:* Connection charges have been debated actively in the United States and the United Kingdom. The US policy is essentially one of shallow connection charges. FERC policy permits utilities to impose charges based on the incremental costs of network reinforcements, but few utilities do. Most utilities charge shallow costs to avoid litigation. If asked to pay for incremental costs, applicants for new connections would likely bring legal claims alleging unreasonableness in their measurement. However, connection policy in the United States contains one element related to deep costs: the schedule of up-front payments. The applicant for a new connection must make a series of payments to the TSO prior to receiving the connection. The payments relate to deep reinforcement costs, but the excess over shallow charges are either refunded within five years in cash or through the grant of a firm transmission right (FTR). In areas that practice locational marginal pricing, an FTR permits the applicant to receive the "congestion rents" from third parties that relate to the reinforcements funded. US connection policy can be described as shallow charges with a forced loan for the deep reinforcement costs.

   Connection charges are shallow in the United Kingdom. The regulator has rejected deep charges out of concern that they would discriminate against entrants and deter competition. However, cancellation fees apply to applicants for new connections in the United Kingdom. The cancellation fees vary by zone, and are higher in congested areas. The differences in cancellation fees by zone relate to the costs of network reinforcements required to expand transmission capacity in each zone. Appendix I describes the extent of deep and shallow charges in the United States and the United Kingdom.

2. *Goals of the Policy:* Deep charges would hold developers responsible for the costs that their siting decisions impose on the network. Responsibility for network costs would motivate generators to locate in the best areas from a network planning perspective, improving the investment climate. Deep charges would also make it very expensive for a generator to engage in a certain type of strategic behaviour. A generator might have to pay a lot of money if it sought to deter rivals by applying for more connection capacity than needed, just to create congestion on the network. The prospect of congestion would raise the connection costs imposed on the applicant.

3. *Assessment:* Deep connection charges can be volatile because network reinforcements are extremely 'lumpy'. We can imagine a series of five connection requests in a particular area, where the first four requests reduce available capacity without requiring any reinforcement, while the fifth triggers a large upgrade to the network. Under a deep connection charge policy, the first four requests would pay minimal costs, while the fifth would pay extremely high costs. The United States and the United Kingdom try to overcome these issues to some extent by spreading costs among groups of generators, as described in Appendix I, II and III. However, the

concept is not likely to work as well in the Netherlands due to the relatively small size of its market.

The lumpiness of network reinforcements implies that their benefits will usually extend to more than one generator. A new connection may require the TSO to install a larger transformer, but an efficient size can be larger than required to relieve the congestion caused by the new connection. Allocating the *benefits* of the reinforcement would also present a challenge. Arguably the generator should receive a share of the benefits that third-parties enjoy from the deep reinforcements. The Netherlands cannot follow the US in addressing this problem through the award of FTRs, unless the Dutch transmission system changes to introduce locational marginal pricing.

We have analyzed the debate over deep and shallow charges in the United States, the United Kingdom and Germany. A consistent theme has emerged. Deep charges find favour among incumbent power companies who stand to lose from the construction of new generating capacity by entrants. Interest groups who support competition seek shallow charges. We describe this debate in the Appendix I.

In May 2007 TenneT organized a workshop to discuss alternative connection policies. Some people in the workshop expressed support for deep charges. One member explained that distribution networks in the Netherlands currently operate a deep connection policy. The adverse effects of a deep policy are allegedly minimal if a network has at least some uncongested areas. Rather than tolerate the potentially arbitrary deep costs of the congested areas, generators can respond by choosing to locate in an uncongested area. In the uncongested area, connection charges are the same as under a shallow connection policy. However, simple adoption of a deep charging policy would require market participants to trust in the continuous availability of uncongested areas. Situations may arise where the network is sufficiently congested that all available sites for new generation face significant reinforcement costs.

Below we discuss an alternative policy called “Just Say No”. In the context of that discussion we explore the possibility of deep charges in some areas if the policy guarantees the availability of shallow charges elsewhere. The guarantee should apply even if connections in the shallow areas might prompt the need for network reinforcements. Deep charges would not apply as a universal principle, but simply as a tool to steer generators from the most congested areas to the least. This approach would mitigate the adverse effects of a universal deep connection policy.

4. *Recommendation:* We do not recommend a universal deep connection policy. Later we discuss the schedule of up-front payments required by generators. In that section we assess the possibility of requiring higher up-front payments in congested areas. This concept draws inspiration from the example of the forced loan that relates to deep charges in the United States, and from the cancellation charges in the United Kingdom. In another section we consider the possibility of applying deep charges only in particular areas of the Netherlands.

Bring back G Charges

1. *International Precedent:* The Netherlands had G charges, and many other countries like the United Kingdom still have them.

2. *Goal of the Policy:* We consider the imposition of G charges that would be fixed per kW. Fixed charges per kW would not distort short-term despatch, and could deter strategic behaviour. A strategy of keeping old plant connected in the hope of blocking rival investments would become more expensive. A G charge might persuade generators to retire old plant to make way for new connections. If the Netherlands had G charges, it could use them to send locational signals, imposing higher charges in congested areas as in the United Kingdom. The "blocking" strategy described above would then be particularly expensive in congested areas.

3. *Assessment:* Existing Dutch legislation would permit the introducing of a fixed G charge per kW. The previous G charge was eliminated in response to concerns with the distortion of cross-border flows. Applying a G charge per kW would prevent the distortion of despatch decisions, but a unique G charge in the Netherlands could distort decisions concerning the construction of new power stations. Generators might prefer to build power stations in interconnected markets that lack G charges. If the interconnectors were congested, then locating in Germany to serve the Dutch market would not be advantageous. However, Dutch –German forward price differences have converged recently, suggesting a lack of congestion looking ahead. TenneT is adding another 1500 MW on the Dutch –German border which would also reduce congestion.

   A system of G charges would provide a mechanism for introducing locational signals to steer new investment to less congested areas. Dutch law would have to change before permitting different G charges in different areas of the Netherlands. Experience in the United Kingdom shows the difficulty of introducing new locational signals. Their proposed introduction prompts intense complaints and litigation from existing generators. For many years the UK energy regulator sought to introduce a new system of locational signals in the treatment of transmission losses. The result was protracted litigation and a postponement of the desired policy for nearly two decades. 18 years after the policy was first put forward, the regulator has still been unable to introduce it. Generators in Great Britain face locational signals through fixed transmission charges per kW, but those signals proved acceptable only because they predated the privatization of the generators. We provide more details of the UK experience in Appendix IV.

   Another issue with respect to locational signals involves the need for stability. A locational signal can be inefficient if it changes too quickly. Imagine that now is a convenient time to invest in the North of the Netherlands, and we establish locational signals to encourage investment in the North. Five years pass, and three new power stations have been constructed in the north. It then becomes convenient to locate in the South. If the system updates the locational signals, then the new power stations in the North may find themselves in a perverse situation. They will have helped the network and responded to a signal, which after their completion reverts to a penalty because a fourth new power station in the North would now create problems. The locational signal can operate a bit like a mirage in the desert: you follow it only to find that it has moved after your arrival. The only way to solve the problem of instability would entail exempting new units from subsequent updates to the signals in some fashion. However, a policy of exemptions can create tensions involving the compensation of the TSO. It is not possible to grant exemptions to all units and simultaneously be confident that the TSO will receive full compensation for the costs of the network plus a reasonable rate of return. If the TSO guarantees benefits to the three new generators in the North, and the TSO in turn seeks compensation from third parties, then generators somewhere else on the network must pay, which is in tension with the concept of their exemption from updates. The only way to give stable and long-term locational signals to generators would therefore entail some financial risk for the TSO. We can imagine an efficient system of financial risks and rewards for the TSO, which could represent a net improvement over the existing system. However, to start incentivizing TenneT with risks and rewards would entail a significant change in philosophy. Designing an optimal system might take several years. We can imagine small systems of rewards and penalties for TenneT in connection with the completion of milestones as described below. Assessing milestones is straightforward. However, it would be quite a challenge to try and steer TenneT to place bets concerning the nature and location of future network congestion.

At the May 2007 workshop to discuss connection policy, several industry participants expressed support for the return of G charges and locational G charges. However, at the workshop participants did not discuss the difficulties in giving generators stable locational signals, or the UK's experience of resistance to the introduction of locational signals. Generators from all regions of the Netherlands were not present at the workshop. We would anticipate conflict if all generators were together in a room and we began discussing a policy of higher G charges in specific areas of the country.

4. *Recommendation:* We do not recommend imposing G charges in the Netherlands. Although the UK has G charges, the UK has limited interconnection with other countries, and therefore less concerns with the potential distortion of investment. The experience of the United Kingdom shows that an attempt to expand locational signals can provoke litigation that prevents the effective implementation of the policy. The introduction of stable, long-term signals would entail some system of financial risks and rewards for the TSO, which can be done and may even be interesting as a long-term goal, but would be extremely complex to design. Perhaps in the long run a policy of locational G charges would make sense, but it would require co-ordination with neighbouring countries and a fundamental change in TenneT's regulation. We do not have any confidence in the ability to implement such reforms in time to address the current problem of network congestion.

Up-front Payments and milestones ↑

1. *International Precedent:* The Netherlands currently requires generators to make a series of payments prior to receiving a connection. The payments reflect the cost of the connection. In this section we consider following the precedent of the United States to raise the payments, reflecting deep connection costs subject to a refund. After the completion of a new power station, the generator would receive a refund equal to the difference between the shallow and deep costs. We also consider UK precedent. The UK does not require up-front payments related to deep charges, but now imposes cancellation payments that are higher in congested areas.

2. *Goal of the Policy:* Higher upfront payments or cancellation payments would deter the strategic behaviour of requesting excessive connection capacity simply to deter rivals.

3. *Assessment:* In the UK generators used to pay shallow costs even if they cancelled their connection agreement, not paying for any deep costs incurred. The TSO has claimed that this system does not stop unrealistic projects from requesting connections, which then require the TSO to invest in reinforcements. The TSO has therefore proposed cancellation fees proportional to the standing connection charge, which varies by location depending on congestion. We like the UK system more than the US system of forced loans related to deep charges. The US system raises the costs of developing a new power station, as the applicant must bear the finance costs of the forced loan. To focus on cancellation payments would relieve the applicant of any funding costs as long as the project proceeded, or as long as another project subsequently took up the connection capacity request. The key idea is that the consumers who pay TenneT's tariffs should not be liable for the deep reinforcement costs that were prompted by an abandoned connection application. If another applicant is willing to take over the connection request (or a part of it) then some or all of the deep costs imposed by the original request will not be wasted; there should be no reason for a cancellation fee.

   An effective cancellation system would require project milestones in the connection agreement: deadlines for the generator to meet related to the advancement of the project. Otherwise the generator would claim that a project has not really been cancelled, just delayed indefinitely. With effective milestones, an incomplete project would pay a cancellation fee and go to the back of the connection queue after a certain point, and TenneT would offer the connection capacity to the next person in the queue. The milestones should allow for reasonable project delays but deter developers from taking excessive time to build their plant, blocking rivals. In the first May 2007 workshop and afterwards, market participants expressed general support for the concept of cancellation fees and project milestones. They offered useful discussion of potential milestones: one participant thought that an especially important milestone was the procurement of planning permission by the generator. While TenneT and generators are best placed to develop detailed milestones, examples from the US include:

- Proof that the applicant has control of the site.
- Completion of a fuel delivery agreement and water agreement, if necessary.
- Control of any necessary rights-of-way for fuel and water interconnections, if necessary.
- Acquisition of any necessary local, county, and state site permits.
- A signed memorandum of understanding for the acquisition of major equipment.

Other possibilities include application for an environmental permit and the performance of an environmental impact assessment. In Appendix III we describe in more detail some of the requirements imposed on applicants for new connections in the United States.

Earlier we mentioned a complaint that has been submitted concerning TenneT's connection policy. Among other things, the complaint cited the lack of any requirement for a generator to tailor the request for new connection capacity to the size of the proposed power station. An effective system of milestones and cancellation fees would address the problem. If the applicant's 'Environmental Permit' mentioned a capacity less than that requested from TenneT, TenneT would reduce the reserved connection capacity.

A generator should lose its place in the connection queue only if there are good grounds to believe that the generator is delaying unreasonably, and there is another applicant further down the queue with a better chance of completing a project more quickly. If a generator suffers the rejection of an environmental permit, but appeals promptly, it would be unreasonable to send the applicant to the back of the queue pending the appeal. All applicants are likely to go through a similar process.

Workshop participants also noted that ideally TenneT should also face milestones – obligations to complete certain tasks within a certain period of time. National Grid has obligations in its license agreement to make a connection offer within a set time of receiving a request, and PJM (a market operator in the USA) is obliged to execute studies within a certain period of time. The absence of private shareholders in TenneT makes it difficult to incentivize the company with a system of financial rewards and penalties. Nevertheless, experience indicates that even a government-owned company will respond to formal obligations. The formality of TenneT milestones would attract attention and highlight the importance of a service-oriented corporate culture.

Possible milestones for TenneT could be:

- Provide applicant with information on the available connection options and the initial estimated connection charge within X days.
- Supply a quotation and timetable for a basic connection design within X days of receiving the request.

- Execute basic design within X days of receiving the order to draw up a basic design, or explain why this is not possible to the customer and possibly DTe.

- Issue a quotation for connection within X days of receiving the request.

However, the precise milestones and timing should be agreed between TenneT, DTe and generators, since only this group has the expertise to develop realistic milestones. In Appendix X we describe the connection milestones that apply to PJM and National Grid.

4. *Recommendation:* We recommend developing a policy of project milestones and cancellation fees. The principle of higher cancellation fees in congested areas would also make sense. We have developed some attractive ideas for the milestones: they could focus on permit applications and progress in securing fuel supplies or equipment. Included in the milestones could be an automatic policy of reducing the connection capacity to match the plant's design capacity. Milestones should apply symmetrically to TenneT. Cancellation fees should not apply if someone further down the queue uses the capacity. We recommend that TenneT engage in a dialogue with DTe and the industry about the precise nature of the milestones and cancellation fees.

TSO reforms:

We consider possible changes to the way that TenneT the Transmission System Operator (TSO) makes decisions concerning new connections, or invests in the network. One possibility is for the TSO to grant firm access rights to all parties requesting connections, regardless of available capacity. The TSO would then address network congestion through redespatch. We call this policy "just say YES". Second, the TSO could alter the "first come/first serve" approach, allowing smaller units to jump the queue for new connections if their particular requests would not prompt congestion. We call this policy "Say YES to small units." Third, the TSO could "Start saying NO" to connection requests in particular areas of the country where connections would pose extraordinarily high costs for reinforcing the existing network. Fourth is the "Advanced Planning/Building" option. The TSO would prevent the emergence of congestion, by anticipating the need for new transmission capacity and either securing the requisite permits or commencing construction before generators requested connections. Finally, we consider the application of a licence regime. A connection agreement would be contingent on the project developer first procuring a licence to build and operate a particular power station.

Just say YES

1. *International Precedent:* In Germany the TSO accepts all requests for connections, regardless of available capacity. The TSO addresses congestion through redespatch until it can complete the necessary reinforcements.

2. *Goal of the Policy:* Saying YES would hope to deter strategic behaviour, as artificial requests for new connections would no longer deter rivals. Saying YES would also

improve the investment climate for project developers by assuring them all of access to the system.

Under the ‘runback scenario’, TenneT interrupts plants with new connections first – a kind of ‘last in, first out’ policy. The efficiency of the system could improve if TenneT just said YES to all requests, and addressed congestion through a competitive redespatch system. Congestion would prompt TenneT to accept an offer from a plant to regulate downward. If power stations bid competitively for downward regulation, TenneT would end up choosing the plant that saved the most money from ceasing despatch, which would be the plant with the highest marginal costs in the congested area: the least efficient plant. With a “last in first out” interruption policy, TenneT instead interrupts the newest plant, which would tend to be among the most efficient.

A rational system of redespatch could create efficient locational signals. Generators would find it most profitable to locate new power stations in areas that were useful for the transmission network. For example, an area with too many power stations would find that not all could despatch simultaneously. TenneT would have to accept bids for downward regulation—what was known as “constrained off” payments in the United Kingdom. Generators in the congested area would in theory compete to offer the lowest bids for downward regulation. A project developer would not want to locate in an area where it foresaw competition with other units to regulate downwards. The developer would instead prefer building in areas where the new power station could actually relieve constraints, perhaps receiving high prices to “regulate upwards”, what were known as “constrained on” payments in the United Kingdom.

3. *Assessment:* To say YES could work in the absence of what we call “local market power”. If only one company owns the unit or units that can redress a transmission constraint, then it will no longer have an incentive to submit competitive bids. A constrained-on generator will have an incentive to bid as high as possible. If only one generator is to be “constrained off” in a congested area, then the generator could ask for an unreasonably large sums not to run. These problems might not arise right now, because TenneT’s policy reduces the predictability of constraints. TenneT does not connect new generators until the network has sufficient capacity to accommodate them, so TenneT does not have to rely to any considerable extent on redespatch. The redespatch situations that arise are infrequent and unpredictable. However, network congestion could become much more frequent if TenneT began to say YES to all new requests. The frequency of congestion would make it more predictable, and companies could begin to abuse local market power.

   International precedent magnifies our concerns over local market power. The abuse of constrained-on payments was investigated by the market regulator, Ofgem’s predecessor OFFER and is discussed in Appendices 1.2 and 1.10. OFFER found that the possibility of constrained on payments led to bids that were often several times higher than otherwise. Although the generators attempted to justify their bids by reference to the reasonableness of their profits, OFFER concluded that the

> present system permits generators located behind transmission constraints to name their own price. It does not provide adequate protection for customers. In a competitive market, customers should not have to rely on generators adopting self-imposed codes of conduct to limit their bidding. If it proves necessary, I do not rule out more formal price control of generators in constrained locations. But such price control would not be straightforward to determine and implement, nor would it address the underlying monopoly problem. A more competitive solution ought to be sought before price control is considered.[2]

The "price control" contemplated by the UK regulator would be the equivalent of TenneT taking over the despatch of plant, estimating the marginal costs on behalf of power stations, organizing despatch and paying them accordingly. Argentina has such a system. While TSO-controlled despatch would avoid the abuse of local market power, it would represent a radical step backwards, would likely present considerably regulatory risk, and cause more problems than it solves. We are aware that both TenneT and DTe have expressed concerns about the competitiveness of the balancing market in general. The market for relieving local transmission constraints would be even less competitive.

In the presence of vertical integration, market participants might suspect that the TSO artificially declares insufficient connection capacity, as a way to protect its affiliated generation business from competition. Another concern might be that first-come/first-served would discriminate indirectly in favour of incumbent generating companies, if they are better placed to know when the network will face congestion problems. Germany's adoption of a just-say-YES policy can find justification in a strong concern for entrants. However, first-come/first-served can work in the Netherlands. TenneT has no incentive to discriminate when measuring connection capacity, and we simultaneous recommend sufficient transparency to give entrants the same ability as incumbents to anticipate network congestion.

4. *Recommendation:* We do not recommend just saying YES.

Say YES to Small Units

1. *International Precedent:* Here we consider a policy where small units could jump the queue for a connection. We have not found any direct precedent for this policy in any of the countries examined. However, the United Kingdom has some special policies for units of less than 100 MW in size, relieving them of the obligation to pay certain network costs. The United States and the United Kingdom have developed special policies for connecting renewables, which tend to be smaller units (see Appendix IV and V).

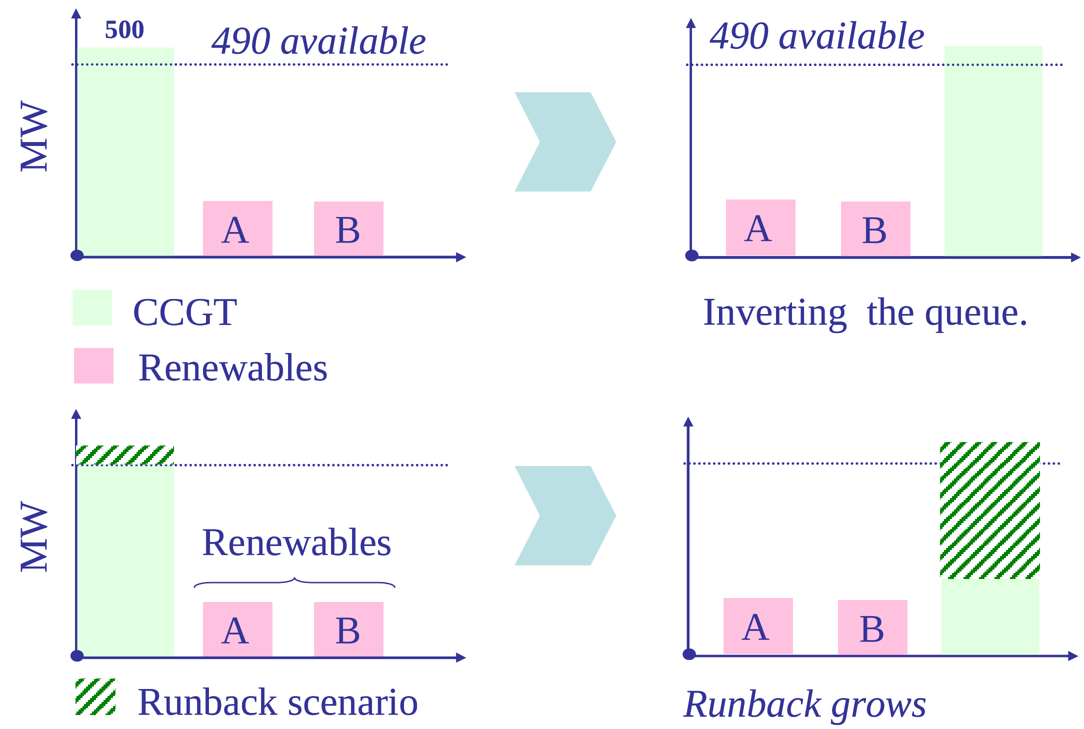
[2] OFFER Report on Constrained-On Plant (Oct. 1992), p.98.

2. *Goal of the Policy:* As we described in our review above, we anticipate a concern that the existing policy has a disproportionate adverse impact on smaller generators, in particular on projects that would use renewable power sources. The specific concern is that first-come/first-serve would permit a large unit to create network congestion stalling the construction of smaller units, even though the network has the existing capacity to handle the smaller units. A special policy for smaller units could ease concerns of discrimination, and could improve the climate for investing in renewable sources of generation.

3. *Assessment:* We are concerned that a policy targeting smaller units would create distortions. In response to the UK's preferential treatment of generators less than 100 MW in size, there are now many projects designed to have precisely 99.9 MW. It is not reasonable to believe that 99.9 MW happens to be an efficient project size. Generators appear to be tailoring the sizes of the units to take advantage of the incentives offered, which runs the risk of creating inefficiency.

   We do not see how TenneT could allow smaller units to jump the queue without harming larger ones. Figure 2 illustrates. The top half of the figure imagines that a 500 MW unit has made an initial connection request. The network can only handle 490 MW. The request by the large unit forces two smaller units A and B to join the queue and wait for reinforcements, even though the network's 490 MW are sufficient to accommodate them immediately, as indicated on the right above the words "inverting the queue". We investigate whether it is possible to invert the queue without harming the large unit. Perhaps the large unit would have to wait for reinforcements anyway, so TenneT could connect the small units first without delaying the larger one.

Figure 2: Smaller Units Jumping the Queue



The bottom half of the figure illustrates the problem. TenneT offers the maximum amount of firm connection capacity available, and then offers a "runback" for the remainder. Figure 2 indicates that the 500 MW unit would receive an offer of 490 MW of firm connection capacity, with the potential to run an extra 10 MW on an interruptible basis. If the large generator accepts this offer, then it is not possible to accept units A and B without reducing the firm capacity offered to the large unit, increasing the amount subject to runback. If the large unit did not accept the runback scenario at all, and insisted on 500 MW of firm capacity, then it would leave the queue, and even under the existing policy TenneT would be able to accommodate the smaller units.

We also note that the larger unit in this example might have an incentive to redesign the project, and switch to a smaller generating unit if it would eliminate the runback scenario and permit the generator to receive 100% firm capacity.

4. *Recommendation:* There is no way to accommodate smaller units without harming larger ones. TenneT's policy does not naturally favour larger units. When project developers learn that there is insufficient capacity to accommodate their request, they already have incentives to reduce their project size. Our discussion here does not address some specific concerns that could relate to the behaviour of large generators: perhaps they hold up smaller projects unnecessarily by requesting more connection capacity than they really intend to use, or by delaying construction unnecessarily. However, TenneT can address those issues by imposing stricter deadlines for the

completion of projects. Cancellation fees can also deter artificial requests for excessive amounts of capacity.

Start saying NO

1. *International Precedent:* Before the liberalization of the electricity industry, central planning was the norm for the construction of generating units in Europe. The government decided where generators would build new units, and was therefore able to consider such issues as the effects on network congestion.

2. *Goal of the Policy:* Refusing requests to connect new generation in certain parts of the network could relieve congestion, improving the investment climate for TenneT. A policy of saying No could also improve the investment climate by permitting TenneT to add connection capacity pre-emptively in certain parts of the country while having a higher degree of certainty of its eventual utilization.

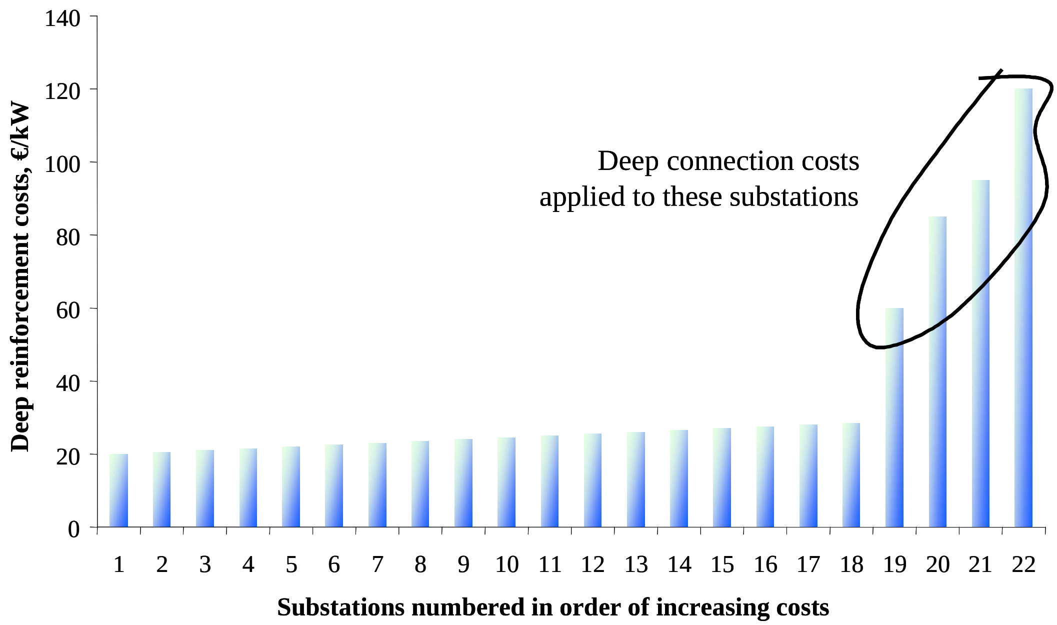
   Assessment: If TenneT decides to reject all further connection requests in the northern half of the Netherlands, we imagine that the established power companies in the north would complain. Power generators in the north could suffer a devaluation of their existing sites, which would no longer be useful for adding generation capacity. We see two potential ways to ensure confidence in the decisions concerning new sites: either formalizing TenneT's policy with guidelines, or asking the Government to make the relevant decisions. One possible way to formalize a say-No policy would involve the preparation of system expansion studies. Perhaps TenneT could only say NO to requests that involved some threshold level of reinforcement costs per kW. TenneT would have to show the generator any studies that estimated reinforcement costs, and the generator would have the option to seek a review by the DTe. If the Government took the initiative, then we could imagine a less technical approach: simply declaring certain geographic areas of the network off limits for new generation capacity.

   Saying No can be too extreme a policy. While connecting a new generator at a certain location may be very expensive, we can imagine circumstances in which a generator would be willing to pay for the associated reinforcement costs. If so, it would seem pointless to refuse the connection. A less extreme alternative of a say-NO policy would be to delineate certain geographic areas of the network in which a deep connection policy would apply. This alternative would differ from a generalized policy of deep charges. To prevent the problems discussed above in connection with deep charges, we would recommend introducing some requirement that at least a certain amount of the network should still have a shallow policy. If Area A has deep charges but Area B does not, then even if connecting a new generator in certain parts of Area B would entail network reinforcements; TenneT would socialize the costs of those reinforcements. Another way to limit the scope of deep charges is to say that they would only apply to reinforcements above a certain magnitude. The challenge would then be to determine a reasonable threshold, which would have to be high enough to make shallow charges realistically available over large parts of the network, but strict enough to apply at least in some locations.

We understand from the second workshop that the current environment has some similarities to a Just Say No policy. If a generator seeks a connection at a site that lacks sufficient capacity, TenneT can ask the generator to wait for several years, or can offer an extremely long and expensive connection to an alternative site with available capacity. Since these alternatives are unattractive, the project developer may offer a contribution to deep reinforcement costs to accelerate the connection. However, a Just Say No policy would differ in material respects from an alternative of negotiated solutions at difficult sites. The Just Say No policy would be more formal, with objective criteria determining where a policy of deep charges could apply. Negotiated solutions would be prohibited in the areas delineated for shallow charges. Furthermore, a Just Say No policy would address situations where reinforcements may be extremely expensive, but would only involve upgrades to existing lines, and would therefore pose no significant issues with environmental permits, taking almost no time to complete. In the current environment, TenneT does not have the leverage to negotiate contributions for deep reinforcements by pointing to the potential of significant delays at such sites.

One possible way to formalize a say-No policy would involve the preparation of system expansion studies. Perhaps TenneT could only say NO to requests that involved some threshold level of reinforcement costs per kW. We imagine that if TenneT calculated deep reinforcement costs for certain geographic areas, there would be clear outliers that had costs in €/kW of new transmission capacity created far in excess of most other sites. Figure 3 illustrates with a hypothetical example where it would be extremely expensive to add connection capacity to some substations. TenneT would show the generator any studies that estimated reinforcement costs (or even simply publish them on its website), and the generator would have the option to seek a review by the DTe. If the Government took the initiative, then we could imagine a less technical approach: simply declaring certain geographic areas of the network susceptible to deep charges. Limiting the scope of deep charges would create more certainty for generators, ensuring that all project developers could avoid the apparent arbitrariness of a deep charging policy unless they felt particularly attracted to the most congested areas of the network. The result would be to improve the investment climate.

Figure 3: Costs per kW of new capacity by substation



3. *Recommendation:* We recommend exploring the Jus Say NO concept further, with two refinements. First, the policy should entail either explicit involvement by the government or a formalized process with decision-making guidelines and the opportunity for appeals to DTe, to help assure generators of reasonable and transparent decisions. Second, generators should have the ability to overturn a NO decision by offering to pay for the associated reinforcements. To Just Say NO should therefore devolve into a policy where a deep connection policy would apply in certain extreme cases. We call this a 'selective deep charges' policy. Part of the challenge would be deciding how to limit the scope of deep charges, either through some investment threshold criterion or on a geographic basis.

Advanced Planning/Building

1. *International Precedent:* Appendix IV describes the new policy in the United States of expanding the network to accommodate renewable sources of generation. Some of the network expansion would occur in anticipation of future demand.

2. *Goal of the Policy:* Advanced planning and building would improve the investment climate reducing network congestion. It would also reduce incentives for strategic behaviour, by avoiding situations the TSO had to offer run-back scenarios that could invite the abuse of despatch patterns.

3. *Assessment:* The Dutch Government has committed itself to certain targets regarding the proportion of electricity that renewable sources should generate. Targets require the construction of a large capacity of wind plant, and there are a limited number of

suitable locations for these wind-farms. However, at present TenneT waits for an application by a wind-farm before commencing the construction of reinforcements. TenneT could accelerate the development of wind farms by planning and constructing pre-emptively, and including the costs in its Regulated Asset Base. On the other hand, pre-emptive investment raises the prospect of forecast errors. Consumers bear the costs of the errors.

Errors are less of an issue where the only costs incurred are minimal. The bulk of the extended time horizon for reinforcements involves the requirements to secure sufficient permits. The costs of securing the permits are much smaller than the costs of the investments themselves. It would therefore seem reasonable to impose two different policies. Without any change to legislation, TenneT could seek agreement with DTe to recover the costs for obtaining permits to expand the network. The expansion itself can be subject to a separate policy, which we describe below.

One possibility would be to involve the Government more directly in dictating pre-emptive investment. We prefer this to the approach in the United States, where pre-emptive investment decisions receive thorough examination in a regulatory proceeding with much of the trappings of litigation, such as the cross-examination of technical witnesses by legal counsel representing different interest groups.

Recent experience in California provides a useful precedent for TenneT. The California System Operator (CAISO) recently applied to the US energy regulator (the Federal Energy Regulatory Commission or the FERC) to build ‘trunk-lines’ to windy areas in anticipation of the construction of renewable projects. Rate payers would bear the cost of the trunk line until renewable generators were able to connect to it. The CAISO proposed the scheme in response to what is sees as a ‘chicken and egg’ problem for renewables, which cannot sign power-sale agreements until they have transmission in place, but cannot fund the transmission without power sales agreements to support any loans. However, the construction of the trunk line is not wholly pre-emptive - the CAISO must demonstrate firm interest in the new trunk line, and a portion of the costs must be covered by standard connection agreements. Imposing similar guidelines on TenneT could help reduce the risk of forecasting errors. We give more details of the developments in California in Appendix IV.

We have received a letter from Norton Rose explaining that the Dutch legal framework already imposes obligations on TenneT to build sufficient capacity, which encompasses the notion of building in advance. Norton Rose also indicates that nothing in the law prevents DTe from approving of advanced construction or permitting.

4. *Recommendation:* TenneT should secure agreement with DTe for the recovery of the costs of securing permits for network expansion, even for potential reinforcements that cannot yet be tied to existing connection requests. It is also interesting to explore a policy of pre-emptive investment. To address the problems introduced by forecasting errors, it would be wise to involve the Government in authorizing pre-

emptive investment, or to impose some guidelines of the nature introduced in California.

License regime

1. *International Precedent:* Many markets require generators to have licences for the operation of each power station. A licencing regime would require the project developer to demonstrate its technical and financial ability to build and operate a power plant. A licence could be a prerequisite to receiving a connection. Norton Rose has suggested that the DTe rather than TenneT should grant licenses. Many countries require generating licenses, and the regulator has the responsibility for granting them.

2. *Goals of the Policy:* A licence regime could deter a certain type of strategic behaviour: requesting a connection with no intent of building a power station. Under the current regime, anyone can apply for a connection despite the absence of sufficient technical skills or sufficient funds to build a power station. A licence regime would narrow the field of applicants to financially sound companies with significant expertise in power station development or operation.

3. *Assessment:* The key threat of strategic behavior comes from existing generators, not potential project developers who lack the financial or technical skills necessary to build and operate power stations. Existing generators would likely satisfy all objective and transparent license requirements of a technical and financial nature. The question then becomes whether the license regime should impose additional requirements to screen out people with inappropriate motives. Unfortunately, no clear test can determine the intent of a generator when requesting a new connection. Milestones and cancellation fees are likely to deter frivolous applications better than a licencing test. Workshop participants also noted that much of the GB generator license was concerned with ensuring conformity with the Grid Code. However, in the Netherlands, the Programme Responsible Party agreement covers much of this ground, so the situation in the Netherlands is not as ‘unlicenced’ as it may at first appear. While a generation license regime may have other merits, we do not see it as a solution for solving the current connection issues.

   A licencing regime could provide an interesting legal vehicle for shifting the responsibility and authority over certain connection issues away from TenneT to the DTe. The DTe would have responsibility for issuing licences, and the authority to revoke them in the event of violations. A shift of greater authority to the energy regulator might help improve the investment climate.

4. *Recommendation:* A licence regime is unlikely to solve the potential problems with strategic behavior. A licence regime could provide an interesting vehicle for shifting more authority on connection policy to the DTe.

Combinations of Policies

In the May 2007 workshop, participants suggested that a combination of policies would be necessary. Here we explore which particular combinations seem attractive.

The merits of certain policies would seem clear even in the absence of others. We do not see any significant cost to publishing more information. Our discussion concerning tradable rights and transparency both involve recommendations to publish more information. TSOs at times hesitate to publish information that entail significant interdependencies. For example, capacity may be available at one site, but only contingent on certain developments at other places on the network. Perhaps capacity is currently available at both sites A and B, but construction at A would remove the available capacity at B. However, TSOs have met the challenges of publishing information that relies on multiple uncertain factors. In the recent past, representatives of gas TSOs argued to the European Commission that it was not even feasible or useful to publish information concerning the capacity of a gas transmission network, because capacity changed constantly depending on the pattern of gas flows. However, publication has since become a requirement that all gas TSOs have satisfied. The market has benefited from the information. We know that National Grid in the United Kingdom publishes significantly more information than TenneT about available capacity, and Elia in Belgium has recently started publishing information on available connection capacity by substation. We have no reason to doubt that TenneT can match the transparency of the National Grid and Elia.

We recommend a policy of securing permits in advance, regardless of the other options adopted. We see little cost to such a policy, while it offers to reduce the lead time of network construction significantly, bringing it more in line with the lead time for constructing new power stations. Reducing the lead times for grid expansion would be a significant benefit for the industry, offering to reduce the price of electricity to consumers by reducing congestion.

A question then arises whether the publication of greater information and advanced permits would alone suffice to address the problems identified with the current policy. Greater information and advanced permits would improve transparency and the investment climate, but would not prevent the emergence of strategic behaviour. We therefore believe that it is essential to explore a policy of milestones and cancellation fees.

The recommendations above together constitute a minimum package necessary to address the various problems that can arise under the current policy. TenneT can implement them without changing legislation. We also recommended exploring two other options: a variant of "Start Saying No" and the concept of TenneT building in advance, as opposed to simply securing permits. Below we discuss their possible roles in combination with the other options.

A 'selective deep charges' policy would not work in isolation. It would raise the importance of transparency. To ask for deep reinforcement costs in selected areas would limit the site locations available to generators, forcing them to rely more on information concerning the available capability of the network. Furthermore, a 'selective deep charges' policy would not prevent strategic behaviour. Generators could still rush to submit applications in uncongested areas, or delay plant construction. A 'selective deep charges' policy would therefore make more sense as a package of reforms including the project milestones, and increased transparency. A ‘selective deep charges’ policy offers one key contribution absent from the other reforms identified: it would serve as a substitute for locational signals that would be extremely difficult to implement. Currently, the length of the queue itself serves as a locational signal, since generators do not want to wait years before they can have firm capacity. But if our advanced permitting policy is successful, the waiting time even for congested areas that require deep reinforcements could reduce considerably. In this case, the length of the queue would no longer be an effective locational signal. The core recommendations above would stop strategic behaviour and improve the investment climate, but would not stop generators from locating in areas that prove extremely costly for the network. A ‘selective deep charges’ policy would provide a strong locational signal.

In theory, building in advance could address almost all problems identified, if supplemented by a system of milestones and cancellation fees. Facing abundant capacity and a downside to submitting frivolous applications or delaying construction, no one would see any advantage to strategic behavior. Arguably the investment climate would be fine without the need for increased transparency. Generators would have confidence in access without knowing details about the system. Even with the existing level of information, we can imagine a certain level of capacity at which the ability to connect everyone becomes obvious. However, we would not recommend this particular package. Building in advance could eventually lead to abundant capacity, but it may take several years. In the meantime market participants would lack the useful guidance of additional transparency.

We also do not see that building in advance is essential for addressing congestion. If TenneT secures permits in advance, then the time horizon for adding new transmission capacity could be even less than the construction of new power stations. While a policy of building in advance is interesting, it is neither necessary nor sufficient for addressing the problems identified. We view it as an interesting option for supplementing the core reforms above. The most interesting aspect of building in advance would be to increase the prospects for achieving the Dutch Government’s targets for renewables, not for addressing the specific weaknesses identified in our report.

We have also been asked whether a policy of Just Say Yes might make sense in conjunction with the other reforms recommended. Just Say Yes would reduce the need for transparency, and would deter strategic behaviour. Our principal objection to Just Say Yes involved the prospect of market power abuse resulting from increased congestion. If the other reforms suffice to reduce congestion significantly, then perhaps TenneT can Just Say Yes without inviting excessive congestion. If TenneT secured construction permits in advance, then it could connect new generators relatively quickly to avoid re-despatch problems. However, we would postpone the adoption of a Just Say Yes policy until after implementing the core recommendations. If the other reforms substantially reduce the amount of applications for new connection capacity, then TenneT can begin to Just Say Yes with the confidence of avoiding significant redespatch problems. We perceive substantial risks to implementing a Just Say Yes policy well before knowing the effectiveness of the other proposed reforms.

Summary

We conclude that a logical core package for reform includes increased transparency, a system of milestones with cancellation fees, and securing permits in advance. We recommend investigating a policy of Just Say No in the most congested areas of the network, which we have modified and called "selective deep charges". The policy would be necessary to send a strong locational signal—an issue that the core package does not address. However, selective deep charges would require changes to legislation, and the policy's merits will depend on empirical study that TenneT must conduct. Building in advance would only make sense if mandated by the Government in response to broad policy concerns like the desire to meet renewables targets. We recommend waiting to see how other reforms work before considering closely a Just Say Yes policy.

Figure 4 below shows the options that we recommend, the refinements that we have proposed when considering them, and the various concerns that the policies would address.

Figure 4: Recommendations

Facilitate Market	Refinements	Goals Addressed
Tradable rights ✓Efficient retirement ✓But with limits Publish more information ✓Available capacity ✓Length of Queue	Just facilitate by publishing info	Transparency, Investment Climate
Generator Payments Up-front payments ↑ ✓Add milestones ✓Deter frivolous applications	Not up front, but cancellation fees with milestones	Strategic Behaviour
TSO Decisions Start saying NO ✓Reject costly locations Advanced planning/building ✓Reduce lead time ✓Efficient for renewables ✘TSO risk	TenneT discretion ↓, & not really "No" Separate Planning from building* * Building not essential	Investment Climate

Appendix I: The debate over deep and shallow connection costs

We have researched the deep vs. shallow connection costs debate in the GB, US and German power markets. Whether a Transmission System operator (TSO) and/or Transmission Owner (TO) prefers to charge deep or shallow connection costs depends in large part on the degree of vertical integration in the country's Electricity Supply Industry. In the presence of vertical integration – where the TO also owns or is affiliated too generation – the TO will prefer deep connection costs. One interpretation is that the TO does not want his own generating affiliates burdened with the reinforcement costs caused by new entrants. A less innocent explanation is that deep connections costs act as a barrier to entry, and hence a vertically integrated TO is keen to apply them t prevent unwelcome competition for its generation affiliate.

For example, the GB (then the England & Wales) market was liberalised with a vertically unbundled TSO, and a relative strong regulator. In the GB market, there has never been any attempt by the TSO to introduce deep connection charges (though the use of system charges vary by location and reflect deep connection costs to a degree, they are the same for entrants and incumbents alike). connection charges have got progressively 'shallower' since market liberalization, expressly to improve competition in the market. In the US, market liberalisation and open transmission access caused vertically integrated utilities to call for a move from the initial shallow connection charges to deep charges. The FERC has made some concessions to the utilities, and connection charges have got deeper since liberalisation began. In Germany, where again there is a large degree of vertical integration, TSOs tried to press for deep connection charges, but these requests were strongly rebuffed both by the regulator and politicians.

In sum, it seems that regulators regard deep connection charges as detrimental to competition; it seems likely that vertically integrated transmission companies are in favour of deep connection charges as mechanism to raise entry barriers to potential competition in generation.

a. The GB market

In the GB market, the regulator (Ofgem) and the TSO have recognised the need for cost reflectivity in connection and transmission tariffs, but at the same time feel that deep connection charges are discriminatory – since some users pay more that others for the same service – and can act as a barrier to competition; Ofgem and the TSO regard deep connection charges as incompatible with the TSO's license conditions, and that it is an 'accepted' fact that they are bad for competition. Hence the moves in the GB market have been to make charges as shallow as possible, while maintaining a system that gives locational signals to generators.

By May 2002, Ofgem and the Department of Trade and Industry (the DTI, the UK Government department that deals with energy policy) had decided to combine the two separate electricity markets of England & Wales and Scotland into a single GB market.[3] The result was the new British Electricity Trading and Transmission Arrangements (BETTA). As a consequence of BETTA, National Grid would extend its authority to set transmission tariffs from England & Wales to GB as a whole. As part of the BETTA design process, National Grid Company (NGC) launched a high-level consultation in December 2003 on the charging methodology that it should use to calculate GB transmission charges.

With regard to deep v. shallow charges, two main areas of debate emerged. The first was connection charges, and the second was the use of system charges. We discuss both issues below.

[3] Although the final legislation to enable this process was only passed in July 2004.

Shallow vs. 'super-shallow' connection charges

At the time of the debate, NGC implemented a shallow connection policy; generators making a new connection to the national grid would pay for all of the direct costs of the connection between their plant and the grid, including any new transformer stations required and the land on which this equipment would sit. Users raised several objections to this connection policy, essentially arguing that the policy was not shallow enough.

For example, if a second user joined an existing connection site the connection charges for each user would change. Each user's new connection charge depended on a number of factors, including what new connection assets were required, whether was any reconfiguration of the circuits connecting the substation, and the type of connection assets installed. NGC concluded that "[t]he original User's connection charges could be higher or lower after the arrival of the new User, and whether the new User benefits at all from sharing may not be clear."[4]

Similarly, the charge for disconnection depended on NGC's assessment of which assets were made redundant by the disconnection, again a function of the other users connected to that node of the network. This made disconnection charges unpredictable. NGC noted that "[e]ach User's overall [disconnection] charge will depend on the commercial decisions of another, and potentially competing, party."[5] A further problem was that when there were more than four connections at a single node, NGC would allocate some – sometimes the majority – of the connection charges to socialised infrastructure charges. Hence user's charges would reduce arbitrarily once there were more than four connections at a single point in the network.

NGC felt that these issues could distort competition and entry decisions. Specifically, generators that could join an existing, heavily used connection point would have a significant advantage over generators that required a new 'spur' connection or were joining a lightly used spur connection. Since sites for new entrants are more likely to require new connections (assuming incumbents own the existing sites well served by the transmission network) the old connection charges could act as a barrier to entry. In contrast, incumbents were more likely to create deep connection charges, which would be socialised, by expanding capacity at heavily used nodes. The problem was also worse for many renewable generators, who nearly always required new spur lines for their connections.

In sum, the problems identified were a smaller version of the problems that arise when implementing deep connection charges for system reinforcement costs – that connection charges will vary arbitrarily from user to user, depending of the history of connection at that point in the network.

To resolve these perceived problems, NGC proposed to move the connection boundary so that all connection infrastructure that *could be shared*, for example a transformer station, would

[4] National Grid, Charging Methodology CCM-M-07 Implementation of "PLUGS" – Change to Connection Boundary and associated removal of Land Charges and Type B Termination Charges and Change to Calculation of Site Specific Maintenance Charges, 21 November 2003, p.5.

[5] *Ibid.*

be socialised via use of system charges, even if the connection applicant was the only party using the infrastructure at the time. Some respondents called this a ‘super-shallow’ connection charge. Similarly, NGC would include costs for land, maintenance and disconnection for equipment that new users could *potentially* use in future – but were not using now – as infrastructure that all users would pay for via transmission charges.

The reaction from the market was, perhaps unsurprisingly, positive, since it involved shifting costs from individual generators to all users, including load. Ofgem approved the proposed changes with effect from April 2004.

The Deepness of GB Transmission charges

At the time of the consultation, NGC applied a system of zonal transmission charges in England & Wales. The charges reflected the Long Run Marginal Cost of connection in each zone – NGC would calculate the effect that new connections in a zone had on overall system costs, and set a zonal charge to reflect this. Hence, the charges were (and still are) a compromise between user-specific deep charges and a ‘postage stamp’ system of uniform transmission charges. The charges users paid would reflect the deep costs they imposed on the system, but would not vary by individual user, and would be relatively insensitive to the history of other connections.

NGC proposed to use to the England & Wales charging methodology for the new GB tariffs under BETTA – a proposal that would lead to high transmission charges in Scotland. During the subsequent consultation period, the issue arose as to the precise way NGC translated the effect of additional generation into incremental costs, which would feed into zonal tariffs. Several respondents proposed that NGC should make charges deeper, by making them more proportional to the costs created by individual users. In other words, the use of system charges would become more uniform, and the charges for individual generators would become more variable.

NGC responded to the idea of deeper connection charges by noting that:

> “deep connection charges are widely accepted as a barrier to competition and on these grounds the Authority has recently approved a move to a shallower connection boundary in England and Wales [discussed above]. Due to the accepted need to avoid deep connection charges, the Investment Cost Related Pricing mechanism was developed as a compromise between the pure cost reflectivity of deep connection charges and the non-cost reflective “postage stamp”.”[6]

So the arguments that were accepted by the regulator for implementing super-shallow connection charges ruled out any move toward deeper charges in the transmission system. NGC also noted that deep connection charges would be inconsistent with its license conditions, and its obligation to “ensure that its use of system charges are non-discriminatory, and do not have the effect of restricting, preventing or distorting competition in generation, supply, transmission or distribution”.[7] In other words, NGC felt that deep connection charges would be discriminatory,

[6] National Grid, ‘GB Transmission Charging: Final Methodologies Conclusion Report to the Authority’ 30 September 2004, p.42.

[7] *Ibid*, p.8.

since some user would pay more for other for the same connection in the same place, depending on the arbitrary history of previous connections.

Ultimately, the regulator accepted NGC's proposal to extend the charging methodology used in England& Wales to the new GB market, without any increase in the 'deepness' of transmission charges.

b. The US

Arguably, the deep vs. shallow debate in the US has been largely influenced by the prevalence in the US Electricity Supply Industry of vertically integrated utilities. Initial proposals for shallow connection costs at the start of market liberalisation met with protests from vertically integrated utilities, which perhaps feared their customers would be forced to pay for the arrival of unwelcome generation entrants. FERC has made some concessions to the concerns of utilities, with the results that the US has arrived at a compromise solution, in which generators contribute to some extent to deep costs but do not pay for all of them.

The GB Electricity Supply Industry (and many other European electricity markets), was a single state-owned entity before liberalization. Accordingly, policy makers were free to design the liberalised market, by deciding how to divide up the ESI before liberalisation. In contrast, pre-liberalisation the US ESI was largely privately owned; therefore one should not regard US connection policy as an optimal, 'designed' policy, but rather the result of the ESI's ownership structure at the start of liberalisation and the compromises that have been negotiated since.

Understanding the US debate

As we describe in Appendix 2, in the US generators pay the shallow costs of their new connections. In some cases they also finance the deep network reinforcement costs that their interconnection requests create, which the transmission owner then refunds to them either completely in cash or through discounted rates for transmission service, or partially by giving them the rights to some of the revenues that their transmission investment creates.[8]

There have been two related sources of debate regarding deep vs. shallow costs in the US. The first is whether generators making interconnector requests should pay tariffs based on the transmissions owner's average $/kW costs, or the marginal cost ($/kW) of the network reinforcement that the generator is responsible for. A second and related debate is whether generators should fund all or a portion of the deep reinforcement costs. The extent to which new

[8] The 'refund' system that FERC allows – either cash refunds or the granting of financial transmission rights – depends on the ownership structure of the Transmission network. If a vertically integrated utility owns the network, FERC will worry that it cannot be trusted to refund a generator (that is competing with its own generation subsidiary) in a fair way by granting transmission rights. Accordingly, FERC will insist on cash refunds or discounted rates for transmission service. If the interconnection request takes place in an area administered by a Regional Transmission Operator (an RTO), which has no financial stake in the market and does not own generation assets, the FERC will endorse refunds via the granting of financial transmission rights. An RTO is in effect a System Operator for the assets owned by a large number of Transmission Owners. While the precise responsibilities of the RTO vary, they also administer centralized spot markets for energy and other generation services, in addition to operating the regional grid.

generators, and other new transmission users should be directly liable for network upgrade costs has and continues to be a very controversial topic in the US.

As with most markets, to a large extent the ownership structure of the Electricity Supply Industry (ESI) at liberalisation has dictated the course of the debate. At the dawn of the liberalisation process, the US ESI was really a system of largely separate vertically integrated utilities, that owned both transmission and generation assets. In this environment, the vertically-integrated utilities had built transmission lines mainly to deliver power from the utility's generating plants to their 'native load' customers – the customers in service areas designated by statute or contract. While neighbouring utilities traded power and shared reserves, transmission was rarely built to facilitate trade between utilities. When long-distance transmission lines were built, it was usually to bring power from specific remote, low-cost resources, such as hydro-electric facilities in the Pacific Northwest, to cities and towns.

Transmission service, like wholesale power service prior to the partial deregulation of wholesale power markets which started to take effect in the 1990s, was priced at "embedded" or average cost. A transmission customer paid a pro rata share of the transmission owner's embedded cost of its transmission system (original cost less depreciation, much like a Regulated Asset Base). "Congestion" was not really recognized or priced—the cost of redispatch was socialized among all users (primarily the utility's native load customers). Building transmission to facilitate regional trade is a relatively new concept in the US.

The US then embarked on the process of opening up transmission access in the 1990s; this led to requests from third-party generators for network connections that required deep reinforcements. This cost would be spread among all users, even though the need for the new capacity was caused by the new users. Many incumbent utilities argued (as they still do today) that shallow connection charges would "subsidize" new users; transmission owners claimed that merchant generators would capture all or most of the benefits of expensive new transmission capacity while imposing the costs on all users. In addition, socialising the costs of deep reinforcements would provide misleading locational price signal; generators would not consider the incremental cost of expanding transmission capacity when siting their plant.

Why were transmission owners in the US so concerned about protecting their customers from the costs of deep reinforcement? After all, the TSO in the GB market had not raised similar concerns upon market liberalisation. Vertical integration in US utilities provides much of the answer. Shallow connection charges made entry easier for rivals that would compete with the incumbent utility's generating plants. Moreover, bearing the cost of deep reinforcement likely would force the utility to raise the rates charged to its native load customers. Many believed it would be inherently unfair to raise the rates of retail customers to pay for new transmission investment that was not necessarily needed to provide them with economical and reliable service.

In response the objections raised by utilities on the absence of deep charges, in the early 1990s FERC modified its transmission pricing policy. FERC implemented what became known as the "higher of" pricing policy—a transmission owner could charge a generator the higher of embedded cost or incremental cost. If the transmission owner either had to (1) expand its transmission system or (2) curtail beneficial off-system transactions (either spot or longer-term transactions) to accommodate an interconnection request, then the transmission owner could charge the user an "incremental cost-based rate" reflecting either (1) the cost of the upgrade or (2) the opportunity cost of the foregone transactions, with the latter capped at the cost of expansion. An important point, however, is that by incremental cost, FERC did not mean direct allocation of the entire cost of the upgrade to the new user. Instead, if a new transmission line cost, for example, $100/kW, the transmission owner would be allowed to charge a rate equal to $100/kW (unless this was lower than its embedded cost, in which case it could charge embedded cost). In effect, transmission customers could be charged for incremental cost on a pro rata basis, but could not be assessed the full cost of an upgrade.[9]

FERC's "compromise" pricing policy satisfied almost no one. Transmission owners generally believed that they should be allowed to charge embedded *and* incremental cost. Transmission owners believed that third-party customers who created the need for new investment should pay for both the existing system (the embedded cost rate) and should pay an additional charge based on the incremental cost they imposed on the network. Transmission have-nots, such as public power companies and large customers, were equally angry with this policy, claiming that incremental-cost pricing was equivalent to allowing transmission owners to extract monopoly rents from the transmission network (presumably because they felt there was insufficient control over how much the transmission expansions should cost). While unpopular, FERC's "higher of" policy has survived largely intact to this day.

Allocating the cost of new transmission investment became a hot issue again at the dawn of the millennium, largely because (1) the US entered a major new generation construction cycle in portions of the country and (2) the FERC was pushing hard for Regional Transmission Organisations or RTOs across the country. The presumption was that an RTO – which owns no generating or transmission assets but is in effect a System Operator – would be more likely to direct the construction of transmission to facilitate power trading, as opposed to building transmission to ensure customer reliability. State regulators want reliable service, but they generally do not want to pay for transmission investments that are not viewed as benefiting small retail customers. Hence this was one reason why many of them objected to the formation of RTOs and the implication of more construction of inter-utility transmission lines.

Participant funding

In practise, despite lobbying by utilities to charge tariffs based on the marginal costs of deep network reinforcements, few utilities actually price their transmission service in this way. This is primarily because transmission owners believe that there will be much argument over the precise measurement of opportunity/incremental cost. A transmission owner may choose to charge the standard, embedded-cost rate rather than take the risk of incurring significant litigation costs only to have FERC disapprove its proposed incremental cost rate.

Instead, some transmission owners and state regulators have gone beyond the "higher of" pricing policy debate described above, and say that merchant generators should be forced to pay

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[9] For example, suppose that, because of the lumpiness of transmission investments, an interconnection request for 300 MW required a transmission line upgrade of 500 MW at a cost of US$ 5 million. This is equal to US$100/kW. The generator would be charged 300 MW x 1000 x to US$100/kW = US$ 300 million.

for all incremental network costs they impose on the grid. That is, small customers should not be forced to pay at all for network upgrades "caused" by merchant generators – charges would be 100% 'deep'.

In the US 100% deep charges is known as participant funding. Many utilities would prefer participant funding, in part, because it pushes even more costs on new entrants, and therefore accts as a more effective barrier to entry. Moreover, participant funding does not require an ex ante determination of an incremental cost rate. Under participant funding, a generator (or, more typically, a group of generators) agrees to pay for specified network upgrade costs, in addition to their direct interconnection costs, as a condition of being interconnected to the transmission network. A "cap" typically is placed on the network costs that the generator is forced to pay (i.e., a generator will not be financially liable if the transmission owner incurs significant, unexpected cost overruns). This approach does not require the transmission owner to establish an incremental cost rate—the generator pays for the network upgrade through a side agreement and then pays the transmission owner's standard, embedded cost rate once the unit is brought into service.

Conclusions

For the reasons given above, large, vertically-integrated utilities have tended to resist transmission expansion (or at least paying for it), but in some cases state regulators are equally resistant, based on the view that small customers should not have to pay for upgrades that benefit merchant generators, or for upgrades that may facilitate the export of low-cost power, thereby raising prices for the very customers that are paying for the upgrade.

Incumbent, vertically-integrated utilities, state regulators, and consumer advocates tend to be the main proponents of deep transmission charging (allocating transmission expansion costs directly to new generators). Generators, power marketers, and large customers are the primary supporters of traditional shallow charging, in which the cost of new network upgrades is rolled in with the cost of all other network facilities (and generators only pay for the cost of their direct interconnections to the grid). These parties point out that the imposition of network upgrade costs on generators can significantly increase the cost of new generation, and therefore are a means by which incumbent, vertically-integrated utilities protect their generation from competition. Moreover, in their view, it is hard to isolate the beneficiaries of new transmission investments, and therefore who should pay for it.

Others, including the electricity practice at The Brattle Group, agree that it is hard to isolate the beneficiaries of new transmission capacity. While such capacity may be built to enable merchant generators to market their power, the addition of new generating resources could yield wide benefits, in terms of lower dispatch costs, reduced market power, greater reliability, etc. In addition, beneficiaries could easily change over time as more capacity is added and relative fuel costs and environmental regulation changes. Moreover, the need for transmission capacity develops over time—it is a dynamic process. As noted elsewhere in this report, deep connection charges place large costs arbitrarily on the unfortunate party whose request forces an expansion of transmission capacity. But previous users claimed the available transmission capacity, so new capacity would not be needed "but for" the usage of these other parties. So direct allocation creates a potential gaming problem, in which new generators and other new transmission customers strive to avoid being the party that gets "tagged" with upgrade costs.

Alternatives have been put forward, among other by Principals of The Brattle Group. We advocated a zonal pricing approach in which there would be higher charges for generators that located in areas that add to prevailing congestion and lower charges if generators located in transmission-constrained load pockets – much like the GB tariff system. But such ideas have not caught on in the US—instead the FERC has preferred to use locational capacity markets to give generators incentives to locate in transmission-constrained areas –generators receive a higher capacity payment if they locate in constrained areas.

At present, most of the debate focuses on cost allocation within the RTOs whose jurisdictions can cover up to 40 transmission owners. RTOs, the FERC and stakeholders are struggling with the issue of how to allocate the cost of large new very high-voltage lines that arguably benefit the entire RTO region. FERC appears to hold the view that transmission upgrades benefit most customers and therefore such upgrades should be paid for by all or most customers. Political pressure has forced FERC to make some concessions to those favouring participant funding, but FERC's preference has been to have broad cost allocation.

c. Germany

Unfortunately there is less public information available about the debate in the German power market. We understand from contacts in the German ESI that there has been a short debate on deep vs. shallow connection costs in Germany, with the (vertically integrated) TSOs arguing for deep connection costs. The TSOs proposed that generators should pay for the grid reinforcement costs that new power plants connection requests cause, to the extent that these costs can be assigned to individual generators.

However, the relatively new German energy regulator (BnetzA) and politicians were strongly of the opinion that TSOs should only be allowed to charge shallow connection costs to the power station operators, to facilitate market entry and improve competition in the German generating market. We understand that the debate ended relatively quickly once the TSOs recognized that there was no political support for their deep connection charges proposal.

The German experience seems consistent with the other two countries studied – vertically integrated TSOs will generally push for deeper connection charges, and strong regulators keen to improve competition will prefer shallow connection charges.

Appendix II: Connection policy developments in the GB market

Generators that terminate a connection agreement with National Grid before the competion of the connection are liable to pay a 'final sum'. The final sum is based on the direct or 'shallow' costs that NG has incurred in preparing the connection. The final sum provides a financial deterrent against signing spurious connection agreements.

National G rid has recently proposed to amend the current system, noting that:[10]

> [t]he current regime has worked well when primarily accommodating occasional applications for large power stations in dispersed locations. However, BETTA reforms and government incentives to encourage renewable generation has led to a significant queue for transmission capacity clustered in specific areas and for power station granularities that are considerably smaller than those that have been previously observed.

These problems appear similar to the current scarcity of connection capacity in parts of the Netherlands. National Grid identified several problems with the existing connection policy, most notably that: [11]

> cost reflective final sums can be very low or zero until work commences [on the connection] and hence there may be little incentive for … [u]sers to fully consider the viability of projects before Bilateral Agreement signature. This could lead to unviable projects being accepted and included in the background against which transmission reinforcements are planned."

While users are liable for the direct or shallow costs associated with their connection upon termination of the agreement, National Grid may incur other significant re-enforcement costs elsewhere in the system, for which the 'final sum' payment would not compensate. Furthermore, generators can evade liability for the final sum by cancelling immediately prior to the National Grid's actual construction of the connection. National Grid has also pointed out that generators can find it difficult to predict the final sum. Once construction has commenced, the final sum will depend on the precise amounts expended at the date of termination.

Finally, National Grid noted that due to the 'lumpiness' of capacity additions, the final sums can vary considerably through time and from developer to developer, turning the final sum payment into something of a lottery. For example, the first wind mills to connect at a particular location could be exposed to a large final-sum payment if it cancelled after the completion of a spur to the main network. Subsequent windmills at the same location would share in the costs of the spur, but would be exposed to smaller final-sum payments upon cancellation, since the final sum would only reflect the new connection investments incurred by National Grid.

National Grid has proposed amendments to the connection policy. The 'cancellation charge' would be set in advance for each connection, and would be the same per KW for all users in the same area. System users would be exposed to a cancellation cost from the moment of signing the

[10] CUSC Amendment Proposal 131, p1 30th October 2006

[11] Consultation Document CUSC Amendment Proposal CAP131 User Commitment, National Grid, March 16th 2007, ¶4.3 p11.

Construction Agreement, even if cancellation occurs prior to the initiation of any work by National Grid. While National Grid may not have incurred shallow costs on the connection, signing the construction agreement could prompt 'deep' reinforcement costs elsewhere in the system.

National Grid proposes calculating the cancellation charge as a multiple of the Transmission Use of System Charge (TNoUS) and the connection capacity. A reduction factor would apply to the charge, increasing from 25% (four years before completing the connection) to 100% the year before completion. The reduction factors would reflect the higher costs of cancellation as the completion date approaches. For example, if a 500 MW power station cancelled a connection agreement two years before its completion date, the costs would be around £9 million or over €13 million.[12] NG estimate that the cancellation fee as proposed would on average cover 50% of the costs of the gird investment required to accommodate all generation entry forecast between 2007 and 2012.

The Transmission Use of System Charge sends strong locational signals to help deter congestion. In Scotland and the North of England TNUoS charges reach £21.5/kW, whereas they are negative (users are paid for their system use) in the south of the country where there is more demand. Tying the cancellation charge to the TNUoS charge would make cancellation much more expensive in the North relative to the South. However, National Grid has proposed a minimum cancellation fee per kW to prevent negative cancellation charges. The proposed system seems reasonable, because new connections in congested areas will generally require more deep system reinforcement.

In sum, the main interesting points of the proposed GB system for TenneT are that:

- National Grid does not believe that the threat of a cancellation fee will suffice to deter connection requests from projects that have little chance of proceeding. The existing policy seems inadequate because the cancellation fee can be avoided by termination prior to investment in the requested connection, even if National Grid has already incurred "deep" reinforcement costs.
- The existing system leads to fees that are difficult to predict, and that vary excessively among projects.
- National Grid's proposal would expose a generator to a cancellation fee even if National Grid has incurred no direct or shallow costs on the connection.
- The proposal departs from strict cost-reflectivity, in that the user could pay a cancellation charge even if no deep or shallow costs were incurred (although NG forecast that the system would only cover 50% of the actual costs on average).
- Cancellation charges are higher in geographic areas that are congested.

[12] Calculation assumes a TNUoS charge of £4/kW (applicable in South Yorkshire and North Wales), to give a total cost of £4/kW x 500,000 MW x 6 x 0.75.

Appendix III: US Connection Policies

The details of connection policy – called generation interconnection procedures in the US – vary slightly between different US markets. However, the Federal Energy Regulatory Commission (FERC), has issued binding Orders that govern interconnection policy. The important features of connection policies are very similar for all markets.[13] Differences tend to relate to the specifics of market design (the use of Locational Marginal Pricing affects some details of the connection policy). We consider the details of the PJM and the CAISO (California) markets – two of the largest in the US.[14]

In common with TenneT, US markets operate a first-come, first-served connection policy. The Interconnection Request must include descriptions of the project location, size, and equipment configuration, as well as proof of right to control the site for the proposed project, and the anticipated in-service date. The in-service date must be no more than seven years in advance, unless it is demonstrated that engineering, permitting and construction of the project will exceed this period. Upon receipt of the completed Interconnection Request, the project is placed in an Interconnection queue. Queue positions depend on the date of submission of the completed Interconnection Request.

I.1. Shallow and Deep Connection Costs

In US markets generators pay for the shallow and deep costs of their connection. However, FERC policy has consistently been that the Transmission Owner (TO) must reimburse an interconnecting generator within five years for any deep reinforcement costs paid for by the generator. The TO refunds the deep costs to the generator, either in cash over a five year period or by granting the generator so-called Financial Transmission Rights (FTRs) for a 30 year period. These FTRs give the generators the right to congestion revenues earned over the parts of the network that the generator financed. Of course, there is no guarantee that present value of the FTR payments will equal the deep reinforcement costs that the generator has financed– the FTR value could be more or less. Nevertheless, the FTR revenues could ultimately compensate the generator for a significant portion of its deep connection costs. FERC has specified this 'rebate' policy because it wants to facilitate the ability of generators to interconnect to the bulk electric grid, and presumably feels that deep connection charges would be a disincentive to connect.

In effect, the US is a system of shallow connection charges and a forced loan for the deep reinforcement costs to the (TO). The requirement for the connection applicant to lend the TO the money for the deep reinforcement costs – which can be millions of Euros – and the uncertainty as

[13] FERC jurisdiction does not extend to Texas. Interconnection policies in that state are set by the Public Utility Commission of Texas.

[14] The PJM material comes from the 'Generation and Transmission Interconnection Process Overview Manual' Section 2: Interconnection Process First Steps PJM Interconnection, L.L.C. 2–4 Revision 01, Effective Date: 02/26/03. For the California market the material comes from the CAISO FERC Electric Tariff Third Replacement Volume No.II ISO Tariff Appendix U, June 23 2006.

to exactly how much of the amount will be paid back, provides a powerful tool for screening out projects that are unlikely to proceed in practise.

However, if the interconnecting generator receives its money back within five years, the generator will not face any locational signals for plant siting. The rebate reduces the incentive for the generator to select the least-cost location from a transmission perspective. FERC recently reaffirmed this policy in its Order No. 2003.

In response to this lack of locational signals caused by the rebate system, CAISO has proposed that it calculate benefits resulting from reinforcements costing more than $20 million, and use the benefits as a cap on the rebate paid to the interconnecting generator. This policy would avoid forcing all network users to pay the costs of 'inefficient network upgrades – where the benefits of the upgrade were less than its costs. This would guard against projects that cause unreasonably expensive deep reinforcement costs. Without locational price signals, CAISO feels that a reasonable backstop is needed to prevent ratepayers from financing uneconomic projects. The CAISO's proposal to apply an economic test to interconnection applications remains pending before FERC.

Calculating deep connection costs

PJM uses a "but for" standard in determining the deep network upgrade costs to assign to a new generator. Under this standard, the new generator pays for network upgrade costs that the PJM system would not have incurred "but for" the addition of the generator's capacity. This is equivalent to charging the generator the long-run incremental cost that it imposes on the PJM grid. To reach this determination, PJM performs a "deliverability" analysis. The analysis evaluates how flows change on the PJM system when the proposed new generator is added to the existing set of generating plants and transmission assets. The analysis also considers new generating plants that have not yet been built but that lie ahead of the applicant plant in the connection queue.

PJM adds the full output of the new generator, adjusted for its expected availability factor, and decreases all other generation in PJM so that total generation in PJM is held constant. For example, if the output of the new generator is 500 MW, then PJM will model injection of 500 MW at the proposed location of the new generator. If the new set of flows causes a violation of any reliability criteria, PJM determines whether the new generating plant is causing 5% or more of the flow on any limiting (overloaded) line. If the new plant's output contributes to 5% or more of the flow on an overloaded line, the new plant is then responsible for paying for the network upgrade needed to bring the PJM system back into compliance with the reliability criteria.

In practice, PJM does not analyze individual connection applications, but groups together applications both geographically and over a six month period, and identifies the additional network costs required to accommodate these projects. PJM allocates deep network upgrade costs to new generators in proportion to their relative impacts on overloaded facilities, using their capacity and contribution to reactive power (shift factor). For example, PJM would analyse all the connections applications received in a six month period that wish to connect upstream of an existing constraint. PJM would then allocate the identified deep reinforcement costs between this 'cluster of projects'. The grouping of projects, both geographically and over time, improves the allocation of deep reinforcements costs. Grouping helps to avoid imposing extraordinarily large reinforcement costs on the first person in the queue, compared to subsequent applicants who might pay almost nothing.

In California, CAISO uses the queue position of each Interconnection Request to determine cost responsibility for required network upgrades. So in general, the CAISO will study interconnection applications in series, and allocate costs to each project as it creates them. However, CAISO has the option to carry out a study for a cluster of new projects, if these projects were all proposed in a similar part of the network at a similar time. In this case, the CAISO would spread out the upgrade costs over all the projects in the cluster.

Once PJM establishes deep reinforcement costs for a specific generator (or group of generators), that generator is not liable for additional upgrade costs spurred by a later queue of generators. Moreover, if PJM subsequently determines that a later generation project benefits from a transmission enhancement prompted by an earlier generation project, that later project may be required to pay a portion of the upgrade cost. In other words, a new generation project ultimately may end up paying less than the upgrade cost initially set by PJM if one or more future projects end up paying for a portion of the upgrade cost.

I.2. Detailed Connection Procedure

US markets apply different connection procedures for large and small generators. The definition of large generators tends to include power stations with more than 10-20 MW. The procedure for generators below 10-20 MW is simpler. We focus on the large generator procedure.

The large generator interconnector procedure has five consecutive steps, which requires the generator to pay increasing fees and prove that the project has passed certain milestones:

1. General Feasibility Study; cost at least $10,000, duration 30 days;
2. System Impact Study; cost at least $50,000; generators must have applied for permits;
3. Facilities Study; at least $100,000; must be requested not more than 30 days after the System Impact Study;
4. Interconnection Services Agreement: Cost is project specific; must be requested not more than 60 days after the Facilities Study;
5. Construction Services Agreement

The fees and milestone requirements help avoid getting 'phantom' projects into the connection queue that cause congestion. After each study, which the generator can challenge, the generators can make a decision to go forward with the next step or abandon the process. For some projects, not all of these studies may be required.

General Feasibility Study

A party wishing to connect a new generation resource or a new transmission facility to the PJM system must submit an Interconnection Request in the form of an executed Generation or Transmission Interconnection Feasibility Study Agreement, and a non-refundable deposit of

$10,000 for a plant over 20 MW. The applicant is obliged to pay the actual costs of studies conducted by PJM on its behalf, and the non-refundable deposit is applied to those costs as work is completed. If the cost of the Generation or Transmission Interconnection Feasibility study is reasonably foreseen to exceed $10,000 before the study begins, PJM will advise the applicant.

System Impact Study

After receipt of the Generation and Transmission Interconnection Feasibility Study results, if the applicant decides to proceed, an executed System Impact Study Agreement must be submitted to PJM with a $50,000 deposit. The System Impact Study is a comprehensive regional analysis of the impact of adding the new generation and/or transmission facility to the system and an evaluation of their impact on deliverability to PJM load in the particular PJM region where the generator and/or new transmission facility is located. This Study identifies the system constraints relating to the project and the necessary attachment facilities, local (shallow) upgrades, and network (deep) upgrades. The Study refines and more comprehensively estimates cost responsibility and construction lead times for facilities and upgrades.

PJM conducts System Impact Studies twice each year – grouping all the connection applications received in the last six months. In situations where more than one generation project violates reliability criteria, cost responsibility for deep upgrades to mitigate such violations will be allocated among the projects in the course of the system impact study.

The identity of all applicants, the size and the location of projects for which System Impact studies have been completed are published on the PJM web site. After reviewing the results of the study, the applicant must decide whether or not to proceed to the next step.

Facilities Study

Upon completion of the System Impact Study, for an interconnection request to maintain its assigned priority, the applicant must execute and return the Generation Interconnection Facilities Study Agreement and the required deposit of either $100,000 or the estimated amount of the applicant's cost responsibility for the first three months of study work, whichever amount is greater, within 30 days. The Generation Interconnection Facilities Study Agreement may also define reasonable milestone dates that the proposed project must meet to retain its assigned queue priority while PJM is completing the Study.

When completed, the Generation and Transmission Interconnection Facilities Study will document the engineering design work necessary to begin construction of any required transmission facilities. The Generation and Transmission Interconnection Facilities Study will also provide an estimate of the cost to be charged to the applicant for attachment facilities, local (shallow) upgrades and network (deep) upgrades necessary to accommodate the project and an estimate of the time required to complete detailed design and construction of the facilities and upgrades.

Interconnection Services Agreement

Within 60 days of the completion of the facilities study, the generator needs to sign an Interconnection Service Agreement which defines cost responsibility for any required transmission system upgrades, confers the rights associated with the interconnection of a generator, and any operational restrictions or other limitations on which those rights depend. To proceed with the project, the applicant must also provide a Letter of Credit or other acceptable form of security in the amount equal to the estimated costs of new facilities or upgrades for which the applicant is responsible. Additionally, within the same 60-day period, the applicant must demonstrate:

- Completion of a fuel delivery agreement and water agreement, if necessary.
- Control of any necessary rights-of-way for fuel and water interconnections, if necessary.
- Acquisition of any necessary local, county, and state site permits.
- A signed memorandum of understanding for the acquisition of major equipment.

PJM may also include other milestone dates for events such as permitting, regulatory certifications, or third-party financial arrangements. Milestone dates may be extended by the PJM in the event of delays not caused by the interconnection customer/developer, such as unforeseen regulatory or construction delays.

Construction Services Agreement

Finally, the generator must sign the Construction Services Agreement (CSA), which lays out the construction schedules and requires that the parties use reasonable efforts to install the various facilities in accordance with the agreed schedule. If the developer is unable to agree the terms of the CSA with the Transmission Owner, the developer has the option to engage his own contractor for the work, as long as the developer agrees to execute the work within a timeline set down by PJM.

Appendix IV: US Renewable Connection Policy

The standard interconnection procedure in US markets is that the generator has to pay for the shallow, and any necessary network upgrades (or deep upgrades). This connection policy is problematic for some renewable sources such as wind farms, solar arrays and geothermal plant, because they must locate in often remote regions where there is a natural resource. But such regions can be very far from nearest grid tie-in point. As a result, the 'shallow' costs of connection can be very large, and the first wind farm at the site would have to pay a large amount to finance the shallow connection costs.

Moreover, there is a 'chicken-and-egg' problem in that renewable developers cannot get a contract to sell electricity to utilities if they do not have transmission lines in place, but they cannot finance transmission if they do not have a contract with the utilities. These issues create a significant barrier for renewable developers and the MOs in terms of financing and constructing a tie line of the appropriate capacity. Recently, the California System Operator (CAISO) applied to the FERC for a system of pre-emptive investment in connections for renewable resources, and the FERC has approved the CAISO's proposal, giving the green light for other markets in the US under FERC jurisdiction to apply similar policies.[15]

The CAISO found that several factors specific to renewable project compound this 'chicken-and-egg' problem including that:

- Multiple competing developers develop multiple generation projects, which makes co-ordination difficult;
- The individual generation resources are generally smaller than typical fossil fuel projects,
- The generation resources will come on-line in relatively small increments over a number of years.[16]

The CAISO noted that current FERC policy – which requires generation developers to pay for the shallow costs of connection – has impeded the financing and construction of lines to access 'location-constrained' renewable resources. The CAISO notes that such facilities have not been built – and are not being built – even though the potential power supplies that could come from such resource areas are significant.

To overcome this problem, the CAISO proposed that the transmission provider pay for the 'trunk line' to the renewable-rich region. Any interconnecting generators will only have to pay for their interconnection to the trunk line plus a share of the trunk-line costs on a pro-rata basis. The transmission provider would include the costs of the trunk line in its rate-base, and other rate payers would continue to pay for any unsubscribed portion off the new trunk line.

[15] FERC Order XX April 19th 2007.

[16] *Ibid.* ¶8 p.4.

To reduce the risk to rate-payers, the CAISO developed a number of criteria and safeguards that would need to be met before the shallow connection costs could be included in the rate base. The main points are:[17]

1. The project must provide access to an "energy resource area" in which the potential exists for the development of a significant amount of location-constrained energy resources;
2. The interconnection project must be a high-voltage line designed primarily to serve multiple location-constrained resources that will be developed over a period of time;
3. The CAISO would have to ensure that the interconnection project will result in a cost effective and efficient interconnection of resources to the grid.
4. To limit the cost impact of the proposal on ratepayers, the total investment in the interconnection facilities under this scheme could not exceed 15% of the total of high-voltage transmission facilities already included in the rate base;
5. The interconnection project must demonstrate adequate commercial interest by ensuring that (a) Standard connection agreements must cover around 25-30% of the new interconnection line and (b) there must be a tangible demonstration of support for the project of at least 25-30% of the capacity of the new project (in addition to the capacity covered under the standard connection agreements). This interest could be shown through formal declarations of interest, assessment of the number of megawatts in the CAISO interconnection queue, responses to an open season, or studies showing the potential megawatt development in a region.

In approving the CAISO's proposal, the FERC noted that "The difficulties faced by generation developers seeking to interconnect location-constrained resources are real, are distinguishable from those faced by other generation developers, and such impediments can thwart the efficient development of infrastructure. In this regard, we find that the CAISO's proposal is an appropriate mechanism to accommodate the unique characteristics of location-constrained resources and that doing so does not constitute undue discrimination against other generators."[18]

The immediate application of the CAISO's new process is to build two 500kV lines into the Tehachapi mountain region in California. The Tehachapi area is an example of a situation where insufficient interconnection capacity has prevented the development of location-constrained resources such as wind-farms. As noted by the California energy regulator (CPUC), the amount of wind generation in the CAISO's interconnection queue for the Tehachapi resource area has increased more than fourfold since the CPUC ordered the local utility to apply for transmission expansion in the area.

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[17] *Ibid.* ¶6 pp.3-4.

[18] *Ibid.* ¶62 pp.19-20.

Prior to the CPUC's action, market participants were only able to privately finance the construction of one interconnection facility from the Tehachapi resource area to the CAISO-controlled grid. With respect to the single line that was constructed, the Commission recently issued a series of orders to address competing requests for capacity. Implicit in these competing capacity requests is the fact that the interconnection facility is undersized and that insufficient capacity exists to meet all requests for service. The haphazard and inefficient way in which the Tehachapi resource area has been developed highlights the need for addressing the incremental nature of renewable development in California.

Appendix V: UK Renewable Connection policy

The network required to connect planned offshore wind farms extends beyond UK territorial waters, and hence does not fall under existing legislation for the regulation of the electricity network. Accordingly, in July 2005 Ofgem and the Department of trade and Industry (DTI) issued a joint consultation on the regulatory treatment of the offshore grid. Essentially two options were put forward:

1. The TO would pay for the development of the offshore grid, and recover the costs through transmission use of system charges. A variant off this approach is that the Government caps the charges, if it judges them to be sufficient to deter the development of offshore wind and hence compromise the Government's renewable targets.

2. The developer would pay for and construct the link between their wind farm and the onshore grid.

Having received responses to the consultation, the Secretary of State opted for option 1, for two main reasons.[19] First and most obviously, in effect lending the wind-farm developer the money for their connections to the grid will encourage the development of offshore wind resources, and is also consistent with the on shore policy. Second, the Secretary of State found that if the TO coordinated offshore grid construction this would reduce the cost and environmental impact of the connections. Individual wind farms might find it hard to co-ordinate their cable projects, and so multiple cables from offshore to onshore might result. In contrast, the TO would have a good overview of all connection applications and be able to co-ordinate construction.

In effect, the UK policy means that other rate payers pay the shallow costs of offshore wind farms' connections, since these costs are rolled into the rate base. In some ways this is similar to the policy recent approved for California (discussed in Appendix IV), with two main differences. First, in GB the TSO must receive a planning application before it starts construction of the offshore cable, so it is not a policy of pre-emptive building (although the TSO may 'oversize' the connection to the first applicant to allow for subsequent projects – the details of this are not yet clear). Second so far at least there do not seem to be any detailed criteria limiting the exposure of other rate payers to the risk of building the offshore network.

[19] DTI, Regulation of Offshore Electricity Transmission, Government Response to the joint DTI/Ofgem Public Consultation, 30 March 2006.

Appendix VI: Connection Policy in Germany

Connection policy is also a current subject of policy debate in Germany, where the Government has introduced new legislation aimed at improving competition in electricity generation and giving incentives to investors in new power plants[20]. In Germany, a desire to increase competition, rather than problems with a queue of generators, has motivated changes to the old connection policy.

The government's intention to introduce the new grid law was first announced in autumn last year, and on the 25th of April 2007 the German Cabinet approved the final draft of the new Grid Connection Law (Kraftwerks-Netzanschluss-Verordnung, KraftNAV), which is now waiting for the approval of the parliament. Final approval is expected in a couple of months, possibly before the end of June. After the law is approved by the parliament, transmission companies will proceed into publishing their new connection policies[21]. We discuss some of the most significant aspects of the new German connection law below.

A firm connection policy

New generators are granted firm connections, even absent network reinforcements. In the past, power plants could only be connected to the transmission grid if the network capacity was in place. If grid reinforcement works were necessary, these would have to take place *before* the station's connection to the grid. One can imagine that, in the presence of vertical integration, the network companies had strong incentives to delay investments in the required deep reinforcements, to delay or prevent entry of plant that would compete with their generating affiliate. Under the proposed new law, power plants will be connected to the grid immediately, even if the required reinforcements are not yet in place. If, following the connection of the new plant, network congestion arises, the TSO deals with this using thee 'normal' congestion management methods of plant re-despatch.

Although this congestion management procedure in Germany is still under development and it is currently unknown what its final structure will be like, we know that the dispatcher in the grid control centre is currently entitled to advise the power stations to reduce/increase power or to shut down. RWE TSO Strom actually applies a re-dispatch mechanism that compensates deviations from the original schedule of the power station between TSO and the power stations.

For power plants that have committed themselves to a specific request for connection to the grid until the end of 2007 and expect to be connected by 2012, there is a limited Third Party Access guarantee for 10 years, when it would come to bottle necks in the German network. By granting a firm connection to these power stations, the government gives them privileged grid

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[21] http://luca.init-ag.de/BMWi/Navigation/Presse/pressemitteilungen,did=200652,render=renderPrint.html

access, even if this leads later to bottlenecks in the grid, that need to be dealt with. This regulation aims at giving an additional drive to investors to speed up projects that are already planned[22].

This solution is the 'firm connection' policy that we advise against in the Netherlands, because it risks creating large system balancing costs caused by market power in the market for constraint resolution services. However, such a policy may be appropriate in Germany because the problems posed by vertical integration and market power in the wholesale market may outweigh increased costs of re-despatch. German policy makers may be willing to increase balancing costs, if the policy improves competition. In contrast in the Netherlands, TenneT has no incentive to delay investment in network reinforcements, as it has no generating affiliate. The problem in the Netherlands is not encouraging new generation, but dealing with the connection of the large capacity of panned generation. Therefore, we maintain while a firm connection policy may be suitable in Germany to overcome problems associated with vertical integration, the policy would not be appropriate for the Netherlands.

Shallow and Deep charges

> Under the new connection law, the applicant bears all the 'shallow' costs related to the connection of the power generating facilities to the nearest grid connection node (§ 8 of the draft law), but does not pay for any 'deep' costs related to the reinforcement of the grid or any other contribution towards network costs. In contrast, under the existing (soon to be old) connection process, the applicant had to pay for facilities (transformers, switchgear bay needed to connect the power station to the substation at the grid connection point, additional lines to reinforce the grid etc.) which then became the property of the grid owner. These were in the past all costs covered by the power station.

Accordingly, like the Netherlands, Germany applies shallow connection charges with no system of locational charges for Generators[23]. Therefore, in future Germany could also experience problems similar to the Netherlands where many generators want to connect in one part of the network that has a particular advantage. However, at present the connection policy seems focused on overcoming the problems associated with vertical integration and encouraging entry, rather than worrying about such entry will be prioritised if it materialises.

- In Germany, for a power plant to get connected to an operator's network, a investor first needs to submit an application for connection to the grid, in which they will provide information in the following categories: a) Location and intended mode of operation (peak, mid- or base-load), b) Intended concept of connection to the network c) technical description of the generator per mode of power generation d) technical description of the equipment and own transformers necessary e) technical description of the wire and wire

[22] Supra

[23] The incentives given to investors with the new law are all related to time (speeding up the process for connection to the grid) and not location. There are no locational incentives in Germany like a g-component in the grid usage tariffs (power stations do not pay for grid usage at all). Source: RWE

system for own connection to the grid f) description of the own allowed generation system[24].

- If the application is qualified, then the candidate power station goes to the next round. According to the new law the grid operator needs to let the applicant know within two weeks on what evidence is necessary for the final connection decision and for predicting the available connection capacities. The grid operator will also let the applicant know of the costs associated with this process. The applicant needs to submit a Feasibility study (Machbarkeitsstudie) to establish that connection to the grid is feasible and viable. Costs for the study are calculated individually.

- The operator and the entrant will agree upon the reservation of a connection point, specific to this applicant. This commitment will become effective as soon as the entrant pays within a month of the acceptance of connection a reservation royalty equal to 1,000 € per MW of network connection capacity in addition to any costs associated with the previous step. The royalty is usually counted by the grid operator as an advance payment against expenses incurred while setting up the connection. If such, a deduction is not possible or the connection process is cancelled, the power station is reimbursed[25].

- The two parties will draft together and sign a connection contract (Netzanschluss-Vertrag). This mainly regards technical issues (the ones already mentioned in the first step of the process, the application). However, apart from agreeing on all technical requirements that need to be satisfied for a power station to be connected to the grid, the connection contract also touches issues such as the power failures and interruptions, the setting up of protocols for mutual exchange of information, the concept of auxiliary power, liability, lifespan of the power plant and clientele as well as legal consequences[26].

The two parties will later sign a commercial contract (or “system usage” contract) which mainly deals with the commercial issues, i.e. charges for individually used grid equipment, charges/reimbursement for re-dispatch, reimbursement for provision of reactive power, charges for metering, system usage charges when taking power from the grid etc.

Transmission companies are obliged to have all application forms and standardised copies of contracts posted in their website. Applicants have instant access to this information. At the same time, they can also be informed of applications of other power stations competing for the same connection point. RWE, for example publishes power plant applications on its website

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[24] http://www.rwetransportnetzstrom.com/generator.aspx/netznutzung/netzanschlussregeln/ kraftwerks-anschluss/language=de/id=226362/kraftwerks-anschluss.html, *Anlage 1a (Kraftwerke)*

[25] KraftNAV, § 4, Anschlugszusage und Netzanschlussvertrag

[26] Supra, § 4 (4)

Appendix VII: Connection Policy in Norway

The vast majority of Norway's electricity is generated from hydro power, and there have been objections on environmental grounds to new projects for electricity generation from fuels such as natural gas that most other countries consider 'clean'. Given this environment there have been few applications for the connection of large new generating plant on the Norwegian high-voltage grid; the problem of 'queues' of generators jostling to connect is not a problem Norway is likely to experience for many years to come.

Given the dearth of new investment, Norway's grid policy focuses mainly on providing locational signals for generators, rather than how to prioritise competing connections.

Generators must pay for new infrastructure between the generating facility and Statnett's grid on a shallow-cost basis, with connection costs agreed on a bilateral basis between the investor/generator and either Statnett (for a high-voltage connection) or the local distribution company who owns the local infrastructure[27]. While the distribution company independently sets the rates it charges new generators for the shallow connection, Norwegian law requires the tariff to be "fair and cost based". There are no deep charges for new connections; the cost of new transmission capacity on the central grid is "socialised", and Statnett does not levy a one-time charge for new generators who wish to connect to the central grid. Moreover, the grid tariff, which is adjusted on an annual basis, does not vary with location.

Even given the absence of deep connection charges or G charges that vary by location, there are still two main sources of locational signal for Norwegian generators. The first is the charge for losses, which vary by location. Because power in Norway flows from the North to the South of the country, applied loss factors are lower in the south of the country to encourage generators to locate there are relieve congestion on the gird (or defer the need for further grid investment).

The second form of locational signal is that Statnett offer a reduced production tariff ("*Nettbegrunnet innfasingstariff*" or NIF) for fifteen years to generators that locate in is "socio-economically desirable" areas. This reduction constitutes a significant discount on the production tariff. The regular production tariff for 2007 is 5.60 NOK/MWh (0.68 €/MWh)[28] , while the reduced tariff is 1 NOK/MWh (0.123 €/MWh)[29]. The NIF was established to encourage new generation in areas currently suffering from a production deficit. Generation eligible for this discount should contribute to postponement or avoidance of projected investments in the grid. Statnett re-evaluates the areas and capacity constraints where NIF is offered on an annual basis, and also the maximum amount of capacity that would benefit the grid in each region. If in a given year more than one generator apply for the reduced tariff, and the total generation capacity of the

[27] In many cases Norwegian market conditions dictate that new generators (with the exception of very small generators) are affiliated with the local distribution company.

[28] Using 8.12 NOK/EURO exchange rate as of May 3, 2007. Source: www.dn.no.

[29] Vedlegg Statnett tariffhefte 2007 at http://www.statnett.no/Resources/Filer/Kraftnettet/Tariffer/VedleggTariffhefte2007.pdf

applications exceed the limit set by Statnett, the generators will be granted a NIF for a certain volume pro-rated according to the size of their applications.[30]

Two conditions must be fulfilled before a generator can apply for the lower NIF tariff: the investor must have received a license/permit from the regulator (*Norges vassdrags- og energidirektorat* or NVE); and the board of the investing company must also have made a firm decision to invest in the new production facility. When both these conditions are in place the probability of an investor abandoning its decision to invest in new generation capacity is judged to be low. There is no procedure in place for penalising an investor who applies for the NIF tariff but does not go ahead with the investment. While in theory this could lead to generators acting strategically to increase the average tariff of rival generators applying for the NIF, in practise this has so far not been an issue.

[30] For example, if investor A applies for 500 MW and investor B applies for 1000 MW of NIF, but there is only 1000 MW available, investor A will be receive a discount for 333MW while investor B will be receive a discount for 667 MW.

Appendix VIII: Resistance to locational signals in the GB market

In the main body of the report we discussed that introducing locational G charges – which vary in different parts off the Netherlands – could create windfall gains and losses to existing generators. This in turn would motivate efforts to oppose the introduction of G charges by generators located in congested areas which would be subject to relatively high charges. This resistance could significantly delay the introduction of a locational G charge, so that this policy would not be an effective solution to problems created by TenneT's current connection policy.

Below we explain that resistance to the introduction of a zonal losses scheme in the GB market – whereby generators located relatively far from the main sources of demand would lose a larger proportion of their production – has delayed the scheme for 18 years. While the GB market does have a system of locational G charges, these were introduced *before* privatization, when the electricity supply industry was State owned. Accordingly, the introduction of locational G charges in the GB market did not create 'winners' and 'losers' – and on privatization buyers were already aware of the transmission charges that they would face.

Below we explain the attempts to introduce a zonal losses scheme in the GB market in more detail

Attempts to introduce zonal losses in the GB market

Discussions over transmission losses in the GB electricity market have extended from the late 1980s to the present day. The issue has been extremely sensitive, provoking litigation by private parties and, more recently, disagreement between the UK energy regulator and branches of the UK government.

In 1989, the regulator published an annual report that described a vision for the future treatment of transmission losses. Charges for transmission losses should eventually vary by location on the network, to provide efficient incentives for despatch and the location of new generation and demand. However, during an unspecified transition period all market participants would share the costs of transmission losses in proportion to the amount of electricity generated or consumed, regardless of location. The political sensitivity of the issue arises because generators in the north of the country could pay significant sums of money under zonal charges for transmission losses, as could consumers in the south of the country. Politicians from the north have consistently opposed the introduction of "zonal" transmission losses.

On 14 November 1995 UK energy regulator wrote to the Pool Chairman expressing concern over the lack of progress on locational issues, and requested that the Pool move forward urgently. This issue was also discussed in the regulator's annual report for 1995/1996 as well as in the November 1995 consultation paper 'The transmission price control review of the National Grid Company'. Two years of debate and study transpired before the old England and Wales Pool could approve a proposal on zonal losses in May 1996, for proposed implementation in 1997.

Teesside Power and Humber Power – both generators with a concentration of generation in the north of England – appealed the decision to implement zonal losses, but the regulator rejected the appeal in February 1997. Teesside Power then sought a Judicial Review of the regulator's decision. They alleged that the proposed arrangements allocated charges in excess of the costs of losses to southern demands in order to provide reduced charges to northern demand, and this constituted a breach of the Pooling and Settlement Agreement (PSA). Some observers noted that, for every year Teesside Power delayed the introduction of zonal charges, they saved millions of pounds in transmission loss charges. This saving was more than enough to offset the legal fees incurred. The litigation continued into 2001, when Teesside Power formally withdrew it in light of the introduction of New Electricity Trading Arrangements (NETA) in England and Wales.

With the consultation process leading up to NETA, the need for locational charging of transmission losses was re-emphasised by the UK energy regulator (Ofgem) and the UK Department of Trade and Industry (DTI). NETA documents (including the 'July Document'[31], followed by the 'October Document'[32], then the 'December Document'[33] and the 'April Document')[34] provide evidence of this. Finally, in May 2001 the regulator published a consultation document[35] specifically aimed at developing the enduring arrangements for transmission access and losses under NETA. However, ultimately the regulator decided not to introduce a system of zonal losses in combination with NETA. It was felt that introducing new trading arrangements and a new system of transmission charging at the same time would be difficult for both the regulator and market participants to cope with. Instead, the regulator adopted a phased approach, promising to introduce zonal losses at a later date.

In January 2003, following the submission by market participants of four modifications related to the introduction of zonal losses arrangements, Ofgem approved the implementation of annual zonal loss factors (based on the previous year's load flows) from 1 April 2004. However, a group of northern generators requested a judicial review of the decision. The northern generators argued, amongst other things, that Ofgem's decision was unreasonable. Despite having the review initially rejected on written submissions, at an initial oral hearing leave was given for a full hearing of the review. The judicial review rejected the modification on the basis that the original decision approving zonal losses was "procedurally flawed."[36] Consequently, the regulator's original decision is void, and the zonal losses modification for England and Wales will not proceed.

In any case, the modification would only have applied in England and Wales; at the time Scotland operated under different electricity trading arrangements. Accordingly, the Department

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[31] 'The new electricity trading arrangements. Volume 1', Ofgem, July 1999

[32] 'The new electricity trading arrangements. Ofgem/DTI Conclusions Document', October 1999

[33] 'NGC System Operator Incentives, Transmission Access and Losses Under NETA. A Consultation Document', December 1999

[34] 'NGC systems operations under NETA: transitional arrangements. A consultation document', April 2000

[35] 'Transmission access and losses under NETA. Consultation document', May 2001

[36] Ofgem decision document published 30th January 2004.

of Trade and Industry launched its own consultation on whether zonal losses should be implemented across Great Britain when the NETA arrangements were extended to Scotland via the introduction of the British Electricity Trading and Transmission Arrangements (BETTA). On 27th June 2003, the Secretary of State for Trade and Industry announced that she was "minded" not to include zonal transmission losses under BETTA. The Secretary of State is reluctant to introduce the zonal losses scheme in the new Great Britain market because it is not clear that the benefits of introducing the scheme outweigh the implementation costs. Nonetheless, the UK energy regulator still appears to support zonal losses, and states that they "continue to regard the adoption of cost-reflective charging as economically and environmentally beneficial in protecting the interests of consumers."[37] In sum, 18 years after the regulator first introduced the idea, zonal losses are still not applied in England and Wales.

[37] *Loc. cit* footnote 36.

Appendix IX: Responses from market participants

Comments from Essent

According to the Dutch electricity act a transmission operator should take care of a connection to his grid if a customer applies for such a connection. Essent believes this should be the starting point of all discussions about necessary new connections to the grid. Also the minister wrote on June 7th to Parliament: "…. *het overheidsbedrijf investeringen kan doen die vanuit publieke oogpunt noodzakelijk en gewenst zijn, maar vanuit commerciële optiek minder vanzelfsprekend zijn*". Discussions about strategic behaviour from generators divert the attention from this starting point.

The opportunity to obtain a connection to the grid including adequate transmission capacity is essential for market development and security of supply. After over a decade of non-commissioning of large generators in the Netherlands, production companies see opportunities to build new capacity and now have to find out that their preferred sites cannot be connected to the grid due to transmission constraints. Liberalization of the electricity market implies that the central planning procedure for grid and production including a risk free return on capital are abandoned. This will undoubtedly lead to other solutions for production locations and different grid configurations. Generation capacity will preferably be built in those areas where conditions for generators are favourable like the availability of land, fuel, cooling water, etcetera. Aligning the grid capacity with these favourable locations should be leading. To facilitate market development and security of supply some surplus of transmission capacity should be available. Also, it can be no surprise to the national transmission operator that producers favour for example locations at the Maasvlakte, Sloe and Eems. Unfortunately the TSO has apparently made other choices which are not aligned with these developments.

Essent strongly believes in a European level-playing-field also for the development of new power generation, so the developments in Germany towards a new legal framework for a firm connection policy cannot simply be discarded.

Brattle mentions "the lack of locational signals" while at the moment producers experience the ultimate locational signal: there is no transmission capacity available! We believe that locational signals for a small country like the Netherlands are inappropriate.

Essent believes that the current TenneT policy with more transparency and advanced planning is adequate to get some relieve for the current transmission adequacy problems.

Essent has the following comments on Brattle's recommendations:

- Tradable rights

Already existing sites with a connection to the grid can be bought by anyone. This recommended reform does not materially change any existing policy, nor does this idea lifts capacity problems.

- Publish more information

At this point in time there is no information available to the market about existing connection capacities nor is there information available about the time it will take to increase capacities. So until a producer applies for a connection he is in the dark about the possibility of obtaining adequate capacity within a certain timeframe. By revealing more information to the market the producers have the ability to act proactively.

- Up-front payments

Up-front payments will have no effect on capacity shortages; it will only create additional hurdles for investors.

- Add Milestones

This will result in endless discussions between TSO and producer. For example: start of construction, can be interpreted as dig a hole (is 1 m3 enough?). The effect is more bureaucracy and an additional hurdle.

- Say-NO

If a TSO starts "saying-NO" for sites that might be expensive for the grid operator but are very attractive for the producer(s), the producer might be forced to invest at a site that is less cost attractive for him and will lead in the long term to higher energy prices. Without a central planning procedure –which is abandoned- there is no way TenneT can make an overall assessment of costs and revenues.

- Advanced building planning

Based on the capacity plan TenneT should have a view on attractive sites for producers. Already prior to a more definitive decision, TenneT can opt for starting the permit procedure. This will speed up the process of actually building the connection.

Comments from Norton Rose

1.1 This is further to the workshop on TenneT's connection policy, held in Arnhem on 22 May 2007 and in response to the request to provide comments to the May 2007 Draft report by the Brattle Group, Ltd ("Brattle") entitled "A Review of TenneT's Connection Policy" ("Report"). This input is further to the preliminary input provided by email dated 31 May 2007. Please note that this memorandum is drafted by Norton Rose and that the views in this memorandum do not necessarily reflect the position of RWE.

1.2 We would like to summarize the comments and suggestions made below in the following manner. The emphasis of the Report is on changes that TenneT itself can make to its Connection Policy. While this is understandable in light of Brattle's instructions, we believe that it is important to craft a policy that is, to the maximum extent possible, in line with the main tenets of the current Electricity Act 1998 ("Act") and applicable EU regulation.

1.3 Main elements of the Act are that the TSO plans, constructs and maintains an adequate network, promotes optimal use and grants (regulated) non-discriminatory third party access to it. If it does so, costs are for the most part "socialised" and the TSO is excused from providing transport capacity if it (within reason) cannot be made available. This regulatory regime, in our view, supports certain suggestions made by Brattle (e.g. Publish information and Advanced planning/building) while it is difficult to reconcile with others (e.g. Deep Charges or "G-Charges", "Just say Yes (to small units)" and "Just Say No"). It does not require the TSO to run financial risk, but does require non-discriminatory third party access and transparency.

1.4 The current EU regulatory framework assumes that a national authority allocates production sites and in many European countries this is the case. It also suggests that allocation of scarce essential infrastructure is done in a rigorous, transparent and non-discriminatory fashion. An important reason to have a national authority allocate production sites is that such an allocation has many public policy elements that are not within the remit of the TSO, for example regional development, industrial policy, employment and -last but not least- development of renewable resources. Allocation criteria of existing capacity should not be made on the basis of the "first come first served" principle, but at least include tests on energy efficiency, and technical, economical and financial capabilities of applicant, and the "use it or lose it" principle.

1.5 We believe that this suggests that allocation of production sites is done by either the Ministry of Economic Affairs or the supervisor Directie Toezicht energie ("DTe") and is subject to temporal and otherwise conditional licenses. Such licenses could provide locational signals and render forced site auctions unnecessary and regulate milestones and penalties for construction and operation of the units. This suggestion requires amendments to the Act, which will obviously take time. In the interim, we believe it would be appropriate for the TSO to implement the suggestions by Brattle in respect of the (limited) auctioning of available capacity (subject to criteria suggested above) and up-front payments. The latter could be implemented in TenneT's connection and transport contracts.

2 Regulatory framework

2.1 The Act (and the articles of association ("articles") of TenneT) provides a description of TenneT's responsibilities with regard to the high voltage grid. The Act creates the statutory duty to connect to, and construct, repair, renew and extend, the grid, as an exclusive task of all Dutch grid managers, including TenneT. Under the Act, TenneT as TSO is obligated to connect third parties to the grid, within a reasonable time, against payment of a regulated tariff and in a non-discriminatory way. Similar obligations apply in respect of transport: TenneT has to transport, except when "within reason" there is no capacity. The tariffs are proposed by the grid manager an approved by the NMa/DTe. Dispensations can be granted by NMa/DTe. Costs are "socialised" and allocated among users in accordance with the Act and the Tariff Code.

2.2 The 2003 Directive assumes that a generation license is required and a number of evaluations are made before such a license is granted. These pertain to general criteria such as "transparency, non-discrimination, safety and security, public health and safety, the environment, energy efficiency and characteristics particular to the applicant, such as technical, economic and financial capabilities". It is important to note that the Netherlands do not require a generation license. Consequently, some of these evaluations are currently made by different de-centralised governments/ authorities, some by TenneT and some not at all.

2.3 Advance Planning/building

2.3.1 We do not immediately agree with the observations in the Report with regard to the ability to reinforce the network in anticipation of future connection requests. The Explanatory Notes (“Notes”) to the Act indicate that the grid manager should ensure that “[s]ufficient capacity (that is to say, sufficient lines of sufficient capacity) [is] present to meet the demand for connection to the grid and transport of electricity”. The Notes also state that grids should be constructed, repaired, renewed and extended “[o]n request or on [the] own initiative” of the grid managers. This indicates that grid managers have a statutory obligation to take the initiative.

2.3.2 The European Commission, too, has voiced its concern over the management and (timely) construction of a European grid on several occasions. As a result of the IEM directives, an obligation for TenneT to monitor the quality of the grid was incorporated in the Act. In a bi-annual Quality and Capacity plan (“Plan”) (Kwaliteits- en Capaciteitsdocument), TenneT must assess current and define future standards for quality and capacity of the grid. One of the aims of this report is a continuous monitoring of the supply and demand on the (inter)national market and resolve possible shortcomings in capacity. In TenneT’s Plan for 2006-2012 the growth in demand and supply of electricity on the Dutch market is assessed in 3 scenarios. TenneT concludes that in all 3 scenarios, an upgrade and renewal of the network is necessary, but dependent on the planned location of new generation capacity.

2.3.3 Both TenneT and Brattle have stated on several occasions that building in advance involves financial risk due to the uncertainty of DTe approval for an increase in overall tariffs. They state that DTe does not approve certain investments without a concrete construction proposal. According to TenneT, this dilemma restricts the ability to build in advance. We do not believe that the regulatory regime imposes a requirement that investments can only be approved if there is a concrete construction request. That would also be difficult to reconcile with TenneT’s statutory obligation to have sufficient capacity available (which obviously requires advance planning and construction). TenneT should therefore be able to get projects cleared by DTe for that purpose. The rules that TenneT has to connect “within a reasonable time” and only does not have an obligation to transport when "within reason" there is no capacity, should be read in conjunction with TenneT's obligation to ensure sufficient capacity and consequently build "in advance".

2.4 Publish information

2.4.1 The Act prescribes that TenneT is obliged to keep information provided to it confidential. According to the Explanatory Notes this obligation is, however, restricted to “business confidential” information.

2.4.2 At present, TenneT uses a very strict interpretation of its legal obligations of non-discrimination and confidentiality. We agree with Brattle on the observations made with regard to the uncertainty and intransparency caused by the current connection policy and the disincentives it gives to investments in new generation capacity. Under the current legislation, TenneT could provide the market with more relevant information needed for planning purposes without compromising its duty to maintain “business confidentiality”. That could include information relevant for an economic feasibility study, information on available capacity and the length of a queue, expected timelines for construction and permitting procedures.

2.5 Deep or G Charges

2.5.1 The Act and Tariff Code currently includes a system of "socialisation" of costs incurred by TenneT for the construction, maintenance and renewal of the grid. Only the costs that are incurred for the connection of a generation facility to the grid will be allocated to that generation facility individually in accordance with the Act and Tariff Code.

2.6 Just say "No" or "Yes (to little people)"

2.6.1 Under the Act, TenneT is obliged to refrain from any form of discrimination in its connection policy and connection- and transport contracts. As a consequence, TenneT is not allowed to refuse any party requesting a connection to the grid. It has an obligation to connect and to transport (albeit qualified by "reasonableness").

2.6.2 TenneT has a (qualified) obligation to connect and transport, in other words "say yes". In doing so, it is not permitted to discriminate between large and small projects or between one fuel type and another. The Act does not provide any justification for such a differentiation. Such a choice involves many public policy elements, which -in our view- should be decided upon by a governmental entity, rather than the TSO.

2.7 Allocation / auction available capacity

2.7.1 The "first come first served"-principle is not stated in the Act. Instead, it is an application by TenneT of the non-discrimination principle (and –as argued below- not always the most appropriate). There is Dutch case law which supports the view that the "first come, first served"-principle as applied by TenneT with regard to the connection procedure is in breach of the principle of proportionality required by the General Administrative Law Act, as its consequences may be disproportionately harsh on newcomers.

2.7.2 Energy transport and distribution networks, as well as interconnectors are generally referred to as 'essential facilities'. Essential facilities are facilities, mostly infrastructures, that '[…] cannot be duplicated for technical, environmental or economic reasons and to which access is required for those wanting to compete on downstream markets'.

2.7.3 General (EU and Dutch) competition law requires firms operating essential infrastructures, such as high voltage grids, to grant access on transparent and non-discriminatory conditions. Several internal electricity market directives ("IEM") have been drafted which indicate that "non-discriminatory access to the network of the transmission (…) operator is of paramount importance", and that "regulation (…) is an important factor in guaranteeing non-discriminatory access to the network". Directive 2003/54/EC, indicates that Member States may impose public service obligations on undertakings operating in the electricity sector if these obligations are "clearly defined, transparent, non-discriminatory, verifiable and shall guarantee equality of access". The Directive states that "[t]he operator of a transmission or distribution system may refuse access where it lacks the necessary capacity". Duly substantiated reasons must be given for such refusal, however. Members States are required to ensure, where appropriate and when refusal of access takes place, that the transmission or distribution system operator provides relevant information on measures that would be necessary to reinforce the network.

2.7.4 The 2003 Directive does not indicate what those reasons should be. In respect of authorisation for new generation capacity, it does, however, refer to more general criteria such as "transparency, non-discrimination, safety and security, public health and safety, the environment, energy efficiency and characteristics particular to the applicant, such as technical, economic and financial capabilities". It is important to note that the Directive assumes that a generation license is required and that these evaluations are made in that stage. The Netherlands do not require a generation license, however. Similarly, it is usage in the upstream industry that when a license is given the "use it or lose it"-principle is applied and technical, economic and financial capabilities of the applicant are evaluated. In the recently published draft regulation for access to LNG terminals, the Minister of Economic Affairs reiterates its commitment to this principle for large-scale energy projects.

2.7.5 The current connection policy of TenneT is not intended nor equipped for the allocation of scarce suitable construction sites for new generation capacity. However, as a result of the current 'first-come-first-served'-principle, TenneT is de facto allocating these scarce suitable sites for the construction of new generation capacity. Under the current connection policy the interests are not sufficiently balanced, but instead are allocated to the first mover without regard to other criteria. The allocation criteria for existing capacity should at least include tests on energy efficiency and technical, economical and financial capabilities of applicant, and "use it or lose it" principle.

2.7.6 It is not TenneT's responsibility to weigh different (local or national) interest in allocating scarce suitable generation sites. This should be done by a governmental entity capable of balancing the wide spectrum of interests at stake. We believe that allocation of production sites should be done by either the Ministry of Economic Affairs or the DTe and should be subject to temporal and otherwise conditional licenses. Such licenses could render forced site auctions unnecessary and regulate milestones and penalties for construction and operation of the units. This suggestion requires amendments to the Act, which will obviously take time. In the interim, we believe it would be appropriate for the TSO to implement the suggestions by Brattle in respect of the (limited) auctioning of available capacity (subject to criteria suggested above) and up-front payments. The latter could be implemented in TenneT's connection and transport contracts. TenneT has, in its connection policy, stated explicitly that it reserves the right to change the connection policy if a change in circumstances should require such a change.

3 Review of existing connection policy

3.1 Below are our initial comments on the assessment of the current connection policy as made in the Report. We will also provide a preliminary overview of our additional concerns with regard to the current policy.

3.2 Preventing strategic behaviour

3.2.1 We agree with the observation made in the Report on the wide spectrum of options for strategic behaviour for incumbents under the current connection policy.

3.3 Promoting a Favourable Investment Climate through transparency

3.3.1 The current connection policy does not create a favourable investment climate (due to uncertainty and intransparency). The current connection policy is intransparent in its application of the "first come first served" principle (when does it apply, when is this communicated to the party concerned and others standing in the queue).

3.3.2 Furthermore, the current temporary solution of TenneT, the availability of run-back capacity, is only beneficial to generators if legal safeguards are in place as to the temporary nature of the measure, transparency of runback circumstances and probability, and dispute resolution mechanism (prevention of unwarranted scale back or cut off). Incumbents should also be prevented from strategic despatch of facilities to prevent run-back capacity from becoming available.

3.3.3 We believe that locational signals should be provided by a governmental entity (in consultation with the TSO).

3.4 Transparency, Confidentiality and Non-Discrimination

3.4.1 Please refer to the above for our remarks on these topics. Greater transparency can be achieved while observing the required confidentiality. The non-discrimination principle does not appear to permit just saying yes or no in general or to a particular group (e.g. renewable or other small projects).

4 Alternative Connection Policies

4.1 We generally agree with the conclusions by Brattle with regard to the alternative connection policies. Below we will highlight some of our additional comments. Please note that our comments include both options for policy under the current legislative framework, but also options that could necessitate new legislation.

4.2 Facilitating Market Transactions

4.2.1 We believe that forced site auctions could in the future be prevented by adopting a system of temporal conditional permits for generation activities. To the extent forced auctions would be necessary, these could be made conditional. We doubt whether the Dutch competition authorities are the appropriate authority to apply this remedy.

4.2.2 We believe that auctioning of available capacity may be appropriate in cases where there is scarce essential infrastructure. We doubt whether such auctions should favour small or renewable projects as this would be discriminatory to the other potential bidders. It may also not lead to an efficient allocation of the scarce infrastructure, which is the objective of the auction. In particular wind energy is highly unpredictable and will lead to inefficiencies.

4.2.3 As regards tradable rights, currently, opportunities already exist to acquire a connection indirectly, via acquisition of the entity to which the connection rights are granted. We partly agree with the observations made by Brattle with regard to tradable rights.

4.2.4 We agree that more information could be published without violating the confidentiality obligation under the Act.

4.3 Changing the payments made by Generators

4.3.1 As stated by Brattle, there is no legal framework for charging "Deep Charges" and they unjustifiably benefit other grid users.

4.3.2 Like “Deep Charges”, we do not see a legal basis for charging “G-Charges”. Locational signals should be given by a governmental entity.

4.3.3 A clear system of up-front payments could be introduced involving milestones and penalties/ cancellation fees / loss of license.

4.4 TSO Reforms

4.4.1 We do not believe that the policy of “Just saying Yes” would work as TenneT does not have sufficient (legal and financial) possibilities to re-dispatch to avoid the resulting congestion. There may also be possibilities to exploit local market power.

4.4.2 Just being positive to small units creates market distortions and appears discriminatory and inefficient. Under current national and European law, TenneT is obliged to provide a connection to all that request this, except under extreme circumstances. Furthermore, the option of giving preference to renewable/ smaller projects is a public policy decision which should not be made by TenneT.

4.4.3 Just saying no does not sit well with the non-discriminatory third party access rule. As suggested by Brattle, the relevant decisions should be made by government. We agree with the refinements suggested by Brattle, which should be investigated further.

4.4.4 We believe that advanced planning and building is already a requirement under the Act.

Comments from Nuon (in Dutch)

Aanvullend kan gesteld worden dat Nuon van mening is dat:

- *Een beleid van meer open informatieverstrekking met duidelijke en eenduidige spelregels een verbetering zal zijn van de transparantie;*

- *Een systeem met '*up front payments*' of '*cancelation payments*'*

bespreekbaar is zolang de omvang en timing hiervan realistisch is en past binnen de fasering van het project. Een aansluitovereenkomst is niet de enige belangrijke voorwaarde voor een project (bouw van een centrale). Het verkrijgen van de benodigde vergunningen van overheidswege is bijvoorbeeld een ander cruciaal aspect op basis waarvan investeringsbeslissingen genomen worden.

- *Ook het tijdig vooruit plannen (van verkrijgen van vergunningen) door TenneT van uitbreidingen in het transportnet is een aspect wat zeker aandacht behoeft. In Nederland zijn er niet zoveel locaties waar grootschalige additionele opwekking haalbaar is (zie SEV), zodat de planontwikkeling van TenneT hier vrij makkelijk en betrekkelijk risicoloos (in geval van niet doorgaan van individuele projecten) op kan inspelen.*

Wij vertrouwen erop dat u onze opmerkingen, voor zover niet reeds door anderen gemaakt, mee zult nemen om de aansluitprocedure te verbeteren.

Uiteraard zijn wij bereidt toelichting te geven indien gewenst.

Comments from EON Benelux

- Generally speaking EBX supports an increased transparency on available transmission capacity and an advanced planning/building as measures to improve the connection policy of TenneT. More complicated steps (like locational signals, etc. etc.) needs a more in depth investigation before introduction in order to avoid market distorting signals.

- The approach in solving transmission scarcity for new generation should be kept as simple (KISS) as possible. There are 2 genuine hot spots: Maasvlakte and Eemshaven, and to some extent the North-Holland coast (wind) and Borssele. Solving the constraints of the top two bottlenecks does not require any complex consideration, but leadership and determination; However, it is obvious that any proposed solution must take into account existing contractual obligations.

- Transparency is required as to the ability of the network to absorb additional generation. The available potential transmission capacity at all main network nodes should be quantified (for format see the Elia website).These numbers will, by nature, be mutually dependant, but will facilitate power plant developers understanding what might be feasible. The issue of limited predictability (loop flows) is an inherent phenomenon, but should not prevent TenneT from providing its estimates and underlying assumptions. An estimate is not a contractual obligation;

- It should be possible to the TSO to give estimates of marginal grid investments/costs per additional MW and the expansion potential per node. This would provide the necessary and helpful economic test to assess likeliness of investments;

- Proactive and advanced planning and building on the most congested transmission routes that need reinforcement by the TSO is a very effective way to accommodate new generation. This would enable to construct the new transmission within the time-frame that is needed to build the power station. It eliminates the timing deadlock caused by long development terms for new lines. Since the development cost (following the appropriate procedures) is relatively low as compared to the actual building, this approach eliminates the risk of stranded investments in networks;

- As to milestones as a measure to prevent parties to keep an unjustifiable position in the queue occupied: in practice it will be difficult for the TSO or regulator to evaluate early in the process whether the intent to construct a power plant is genuine, or to know at all that the next one deserves a preference. The determining issues for the time schedule are at first not very costly (engineering contracts, internal development), and parties can construct any contract (include cancellation clauses etc). Later on, it is obvious if one gets permits, or if major works take place, but that is not the phase that this measure should target; therefore, if milestones are introduced they need to be objective, reasonable, non-discriminatory, and also applicable for TenneT's grid-expansion projects.

- All presented measures to keep generators from misusing their position at existing sites, are solutions for non-existing problems/issues. Old generation either runs or is taken down for new developments. It is hard to imagine that parties will be able to abuse market power at locations with an excess of generation; Nevertheless some remarks to these measures:

- To add an utilization period to a grid-connection will be difficult to implement in a fair and economically efficient way. At the same time it adds a new uncertainty to the investment decision to be taken by an investor. What is the life time of a plant? We know of 40 years old coal plants that are still profitable. The life time for nuclear could even be 60 years. What number to pick, and on what grounds, and would it have any significance?

- Use-it-or-lose-it is also hard to imagine to work fairly and effectively. If an operator mothballs, or decommissions a plant but keeps the site and connected transmission rights, and does not use it for new developments immediately, the reason most likely is that there is already an excessive number of plans in the pipeline. Competition for that particular transmission at that particular time, would not be efficient. Moreover, if such legislation would be in place the operator would have means to prevent losing its rights by keeping the plant alive, which is also not efficient;

Appendix X: Milestones for PJM and National Grid

PJM

PJM's milestones relate to the speed of performing studies. We understand that the Milestones are generally on a best endeavours basis, and that there is little or no penalty for PJM if it fails to meet them. For example, PJM staff commit to conduct the Generation and Transmission Interconnection Feasibility Study within 30 days. If this is not possible, PJM must notify the applicant and provide an anticipated completion date. PJM then commits to perform the System Impact Study within 120 days. If this is not possible, PJM must notify the applicant, providing an anticipated completion date and explaining the need for additional time. If the customer decides to build its own connection, PJM then has a number of specified times within which it must respond during the construction process. For example, PJM states that it will provide comments on the design drawings within 60 days after their receipt. The lack of a response from PJM within the sixty days implies approval.

National Grid

National Grid has a licence obligation to offer a connection within a defined timescale. National Grid's obligation is less detailed than PJM's, but is more onerous due to the threat of licence revocation. The schedule for making an offer depends on the type of agreement requested by the customer, and the need for any works to facilitate the connection. There are no obligations to execute the actual connection within a specified time, only to make the offer.

All timescales apply from the date that the customer completes its connection application form, providing the appropriate technical data and paying the relevant application fee. The relevant timescales for each agreement type are:

- Bilateral Connection Agreement - 3 Months
- Bilateral Embedded Generation Agreement (where works are required) - 3 Months
- Bilateral Embedded Generation Agreement (where no works are required) - 28 Days
- Bilateral Embedded Licence Exemptable Large Power Station Agreement (where works are required) - 3 Months
- Bilateral Embedded Licence Exemptable Large Power Station Agreement (where no works are required) - 28 Days.