

**RECOMMENDATIONS FOR  
THE DUTCH ELECTRICITY MARKET  
NOVEMBER 2001**

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## 1. Executive Summary

In late June and early July 2001, the Amsterdam Power Exchange (APX) witnessed extraordinary price spikes. For two weeks, prices frequently reached levels of 600 €/MWh or more, with peaks reaching 1,200 €/MWh. We have compared these spikes to historical pool prices in England & Wales, and determined that over a period of several years, England & Wales has never witnessed a similar episode.

The unusual nature of the price spikes has provoked a serious and broad analysis of the Dutch power market. We have examined whether the price spikes could be attributed to insufficient capacity relative to demand in the Netherlands. However our analysis shows that the reserve margin in the Netherlands is not significantly lower than has been witnessed in other countries.<sup>1</sup>

*The principal cause of the spikes appears to be plant outages in Belgium and the Netherlands, combined with a lack of sufficient transparency.* In Belgium, outages of two nuclear units and problems with the French-Belgian interconnector created a demand for exports from the Netherlands. The Dutch market therefore had to supply domestic Dutch demand as well as demand in Belgium through the Dutch-Belgian interconnector. At the same time, the Dutch market experienced major plant outages. Our data, which is largely restricted to units greater than 60MW, shows that only 80% of installed domestic capacity was available at critical points in time. By modelling the Dutch power system in detail, we have confirmed that the outages could have been expected to produce serious price spikes at the times actually witnessed. Serious negative imbalances during the price spike periods also confirm the scarcity of capacity. The prices witnessed in the APX make sense if the market perceived that capacity was sufficiently scarce to threaten a black-out. Under such circumstances, even well-functioning markets should produce very high prices. Given the absence of full information on available capacity and demand, it was reasonable for market participants to perceive a significant threat of a black-out.

Some reductions in capacity could be expected due to hot weather, as regulations restrict the operation of some plants to prevent excessive temperatures in the rivers where they discharge water.<sup>2</sup> However, the outages appear extraordinary considering that almost no units had planned maintenance at this time in the Netherlands. We have examined how frequently such a level of cumulative outages could be expected, given reasonable estimates of accidental outages for each plant and the distribution of capacity in the Netherlands. We estimate that an episode of outages reaching cumulative levels of 20% of domestic capacity can easily be expected to occur at least once a year. Our analysis

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<sup>1</sup> The smaller size of the Dutch market means that, for a given reserve margin, and comparable system characteristics, it has lower reliability than a larger market, and would therefore be more vulnerable to price spikes. However, the size of the price spikes appears extraordinary even bearing this in mind.

<sup>2</sup> Hot weather also reduces the capacity of gas-fired power plants by impeding their efficiency. However, the figure of 80% already takes into account the impact of hot weather.

suggests that price spikes will continue to be an inherent problem in the Netherlands, because the market is so small that a few unusual simultaneous events can have a significant impact on available capacity. The number and diversity of units in significantly larger markets such as in the United Kingdom and Germany make them far less prone to disruption from accidental outages. *Our analysis provides strong support for TenneT's decision to expand interconnector capacity through the addition of two phase shifters.* Increased interconnection will contribute to improved reliability by diversifying risk and making a much larger set of units potentially available.<sup>3</sup>

We have examined the market structure, conduct, and performance of the Dutch power market to shed further insight into the price spikes and to derive potential recommendations for reform. Our analysis of market structure considers the concentration of capacity ownership, to determine whether significant market power problems can be expected. We have identified distinct baseload and peak markets. Concentration levels in each market are not so high as to expect the sustained problems that have prompted the forced divestiture of capacity in other markets, such as England & Wales. However, concentration levels are still sufficiently high to warrant careful vigilance for market power problems. The DTe has limited the amount of interconnector capacity that can be purchased by any one party. Our analysis suggests *that the cap on purchases of interconnector capacity is essential for preventing acute concentration problems in the peak market.*

One crucial issue in the analysis of market conduct is whether generators might have induced capacity scarcity by declaring false outages. The evidence available to us was not sufficient to draw a firm conclusion on this issue. Some generators certainly had significantly lower levels of capacity available at critical times than others, but statistical analysis of the data shows that the observed levels of generator-specific outages could simply be a matter of random chance. *Nonetheless, we discuss below recommendations for facilitating the detection of any inappropriate capacity withdrawals in the future.*

Another aspect of market conduct was the inability of two gas-fired generators to produce at maximum capacity despite the absence of any technical problems. The power plants had exhausted their level of contracted fuel supplies with Gasunie, and faced the prospect of significant imbalance charges from continued operations. We have determined that the imbalance charges would have been so extraordinary as to warrant prices of many thousands of €/MWh to justify continued generation.<sup>4</sup> *We conclude that the current Gasunie imbalance policy has a negative impact on the electricity market.*

We analyse market performance by asking whether the prices reached on the APX are so high as to provide excessive returns on power plants that are utilised only infrequently.

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<sup>3</sup> We believe that these effects outweigh the disadvantage that the TSO has less ability to control the despatch of units exporting to the NL from other control areas.

<sup>4</sup> Continued generation for a single hour could warrant a price of over €9,000/MWh (this figure would fall significantly if generation continued for further hours on the same day)

We conclude that *the APX prices over the past year, including the price spike episodes, have not been so high as to provide excessive returns on peak plant.*

We also assess the transparency of the market. Our analysis suggests that the high prices may have been due in part to insufficient information. Although the high prices implied significant concerns with a potential black-out, we estimate that the market still had roughly 1,000 MW of available unused capacity for an extended period during the price spikes. Had information on demand and availability been provided, concerns over a black-out may have been less, resulting in lower prices. We conclude that *too little information is published to permit all market participants a full assessment of market fundamentals.*

We recommend the following changes to the market:

1. *Outages:* Belgium and the Netherlands should establish separate but co-ordinated programmes concerning maintenance schedules. The programmes should require generators to notify schedules in advance, should allow Transmission System Operators (TSOs) to veto specific maintenance plans, and should restrict the ability of generators to revise maintenance plans. Generators should be required to maintain records concerning unplanned outages, and regulators should have the authority to investigate unplanned outages.
2. *Transparency:* Total hourly electricity demand in the Netherlands and Belgium should be defined, measured and published (both *ex ante* predictions and *ex post* data). Interconnector availability, flows and the availability of generation capacity should be published. The actual output of each plant should be provided to TSOs, but published only with a delay of several months. Maintenance schedules should be published, as well as all medium and long-term plans for construction and mothballing or retiring capacity.
3. *Declaring Positions:* All players should be obliged to inform DTe of their net contractual position.<sup>5</sup> DTe would then publish summary statistics on an anonymous basis, including a measure of the concentration of ownership of remaining uncontracted capacity (the HHI index).<sup>6</sup>
4. *Natural Gas Imbalance Charges:* We recommend that TenneT discuss with Gasunie the effects of its imbalance policy on the electricity market, including its potential to artificially limit the availability of peaking capacity. We also recommend that Gasunie permit and facilitate the trading of imbalance positions among suppliers.

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<sup>5</sup> By net contractual position we mean whether and by how much players are long or short on their bilateral contracts. On an aggregate basis, net contractual positions can be indicative of future activity on the APX market.

<sup>6</sup> The calculations and publication requirements should take into account both ownership of physical capacity and equivalent contractual commitments.

5. *Balancing Market*: Greater liquidity in the balancing market could help reduce price spikes. We have reason to believe that some generators participate in the balancing market less than they should. As parties learn the new system better, they may become more willing to offer capacity, since this appears to be economically rational. We therefore recommend that TenneT review the balancing rules to ensure they do not provide any disincentive to efficient participation. TenneT should also provide additional information and explanations of the mechanics of the balancing market and its implications for risk allocation.
6. *Single Benelux Market*: The formation of a “single Benelux market” is being considered.<sup>7</sup> Fundamentally, the existence of a single market depends on economic criteria, and in particular on whether the Dutch-Belgian interconnection capacity is a binding constraint on cross-border trade. However, institutional changes of the kind proposed can nonetheless have significant impact. We *fully endorse the evolution of Belgian access rules* to approximate the rules currently in place in the Netherlands. We recommend co-operation between DTe and CREG, and between TenneT and Elia, to ensure effective regulation and monitoring. However, we urge caution before changing the current system of allocating transmission rights by competitive auction. Advantages of the current system include transparency, the provision of long-term signals, allocating interconnector costs directly to users, and the ability to impose a safeguard against any concerns about market power (through the 400 MW net capacity limit).
7. *APX Price Cap*: The APX should eliminate its maximum price. The current cap could inadvertently serve as a focal point for nervous bidders, or for collusion. The cap may also facilitate bidding strategies by importers that effectively by-pass the APX.
8. *Interconnector Capacity Cap*: The cap on purchases of interconnector capacity should be revised to consider the total market share of each company, considering both physical capacity and equivalent contractual commitments. Thus a firm that owned little or no domestic capacity in the Netherlands would be able to buy more interconnector capacity than a company with large amounts of domestic capacity.
9. *Interruptible Capacity*: It is important to ensure the maximum possible utilisation of interconnectors, for reasons of economic efficiency and system reliability. The introduction of interruptible capacity could enhance utilisation. However, we understand that this might also impose significant costs. We therefore recommend that TenneT examine the potential costs and benefits of interruptible capacity, and the feasibility of securing co-operation from neighbouring TSOs.

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<sup>7</sup> Such a programme would include measures to co-ordinate access rules and other TSO systems and procedures, and potentially changes to the treatment of the Belgium-Netherlands interconnector (e.g., the introduction of a single pool with market-splitting, or the use of co-ordinated redespach by TSOs to avoid congestion, with the costs “socialised” via inclusion in transmission tariffs).

## 2. The Price Spikes

Last summer, the APX witnessed unprecedented price spikes.<sup>8</sup> The spikes occurred during late June and early July, reaching levels of up to 1,200 €/MWh. We assessed the APX hourly day-ahead prices from January 1<sup>st</sup> to August 31<sup>st</sup>, 2001, and defined a “price spike” as a price above 250 €/MWh.<sup>9</sup> From January 1<sup>st</sup> to August 31<sup>st</sup>, 2001, 44 price spikes occurred, most within seven days at the end of June and in early July.<sup>10</sup> Table 1 lists the price spike days and corresponding peak APX price in June and July.

**Table 1: Netherlands' Price Spike Days**

Date	Hour	APX Day-ahead Price (€/MWh)
[A]	[B]	[C]
25-Jun-01	17	350
26-Jun-01	15	300
02-Jul-01	11	600
03-Jul-01	12	1,000
04-Jul-01	12	1,201
05-Jul-01	12	495
06-Jul-01	12	1,200

### 2.1. Comparison to England & Wales

Similar price spike episodes have not been witnessed in the England & Wales electricity market. Assuming the same price spike definition as used in our analysis of the Dutch 2001 prices, a maximum of seven price spikes occurred in the England & Wales market within one year from 1992 through 1998. During most years, no comparable spikes appeared at all. Additionally, the England & Wales prices have demonstrated much lower volatility than the APX 2001 prices. Figure 1 shows the daily variation in England & Wales prices for the year 2000,<sup>11</sup> after normalising them to match the 2001 APX mean. Figure 1 also shows the APX 2001 prices. The prices in England & Wales demonstrate much less volatility than the APX prices.

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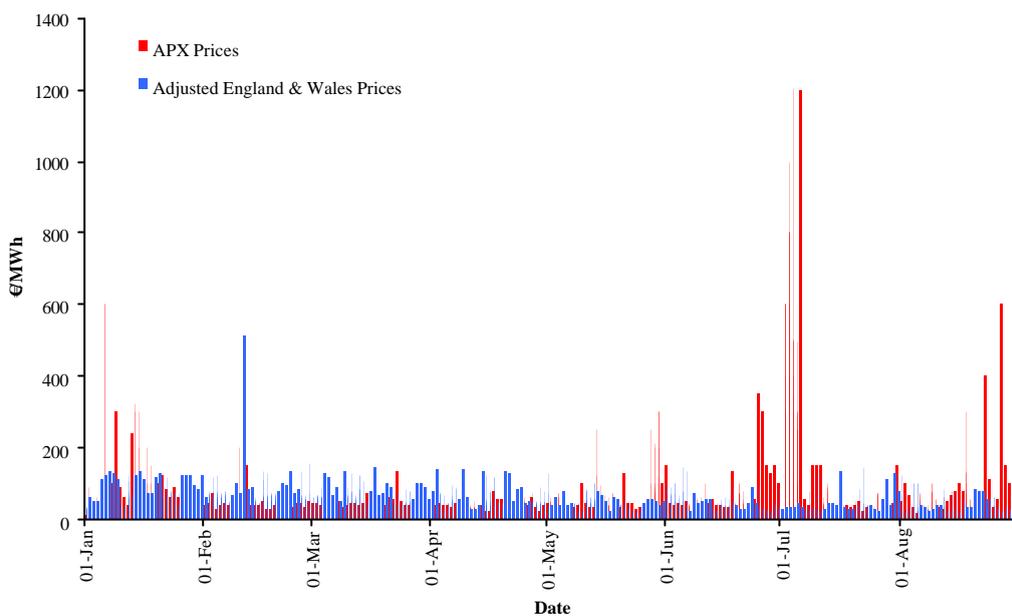
<sup>8</sup> The Dutch electricity markets are described in detail in Appendix 1.

<sup>9</sup> A price of 250 €/MWh is more than four standard deviations from the mean day-ahead hourly APX price from January 1st through August 31st. The mean price during this period was 32 €/MWh, with a standard deviation of 53 €/MWh.

<sup>10</sup> Eight, five and six APX price spikes occurred in January, May and August, 2001, respectively.

<sup>11</sup> We used prices from 2000 for England & Wales, since the data for 2001 have been affected by the abandonment of the electricity pool and the switch to the New Electricity Trading Arrangements.

Figure 1: Comparison of APX and England & Wales Prices



The comparison to England & Wales is even more striking because the reserve margins of the two countries are roughly comparable. We calculate a Dutch reserve margin that accounts for the interaction between the Dutch, Belgian and German power markets. We add German import capacity to domestic installed capacity, and add Belgium export capacity to domestic demand. Our calculation reflects a situation where problems in Belgium convert the Dutch-Belgian interconnector into a source of additional demand for Dutch power.<sup>12</sup> Our result is 26%, which compares to a reserve margin for England & Wales of 27% in 2000.<sup>13</sup>

Additionally, the Dutch reserve margin exceeds the 20% figure that is commonly cited as appropriate to ensure reliability.<sup>14</sup> The spikes appear even more extraordinary in the presence of a reserve margin that would appear to meet international standards, although we acknowledge that prudent reserve levels depend on such factors as the size and number of units in a particular system. We conclude that a broad analysis of the

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<sup>12</sup> During the APX price spikes, some of the Belgian interconnection cables switched from supplying the Dutch market to importing power from the Netherlands. Our calculation of the reserve margin accounts for this switch. Different utilities in liberalized markets treat cross-border flows in a variety of different ways in defining the reserve margin—there is no unique definition.

<sup>13</sup> England & Wales reserve margin calculated from NGC Seven Year Statement, for the years 1999/00 to 2005/06, Volume 1, Tables 3.7 and 2.7.

<sup>14</sup> Market participants in the US PJM market are required to maintain excess capacity of 20%. In the United Kingdom, the parameters for making capacity payments were derived under the assumption that a reserve margin of 20% would produce an acceptable level of security. Our practical experience with unregulated markets has also been that new plant is demanded when reserve margins threaten to fall below 20%.

Dutch market is warranted. We explore the causes of the spikes in greater depth and recommend reforms for preventing their recurrence.

### 3. Accidental Outages

*The principal cause of the Dutch price spikes was significant plant outages in both Belgium and the Netherlands. Severe outages in Belgium created a demand for exports from the Netherlands, even as outages in the Netherlands reduced the market's ability to meet domestic demand.*

#### 3.1. Belgium

Severe outages in Belgium sustained the demand for exports from the Netherlands during June and July. ----- reported offline, removing a total of about 2,000 MW from the Belgium market. ----- . Simultaneously, Elia was forced to reduce capacity on the Belgian-French interconnector by 400 MW from June 25<sup>th</sup> to July 6<sup>th</sup> to preserve system security.<sup>15</sup> The loss of 2,400 MW in Belgium comprised about 15% of its available capacity.<sup>16</sup> ----- outages and reduced interconnector capacity on the French-Belgian border required Dutch generators to serve Belgian demand.

#### 3.2. The Netherlands

The Netherlands simultaneously faced major plant outages. Although no plant maintenance was planned during late June and early July, only 80% of installed capacity controlled by ----- was operating during some of the price spike days.<sup>17</sup> This calculation includes mothballed units in the definition of installed capacity. If we exclude the mothballed units and add two large industrial units that were operating, the figure rises to 84%. Table 2 shows the availability for July 2<sup>nd</sup> at 11:00 am, which was 87%, and we note that results were hardly better during the other price spike days.<sup>18</sup> High summer temperatures contributed to the outages, as some plants curtailed output to avoid excessive temperatures in the rivers where they discharged water. Some gas turbines naturally produce less when temperatures are high because the heat reduces

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<sup>15</sup> Platts' European Power Daily, Volume 3, Issue 122, June 26, 2001, p. 4/6 combined with information from TenneT. Because ----- outages increased transit flows through Belgium, ELIA had to curtail French import capacity to preserve system stability.

<sup>16</sup> UCTE reported that Belgium had available 15,729 MW at the end of 1999.

<sup>17</sup> All of our figures ----- is mostly limited to generating units greater than 60 MW. Total capacity in the Netherlands is closer to 20,000 MW. -----

<sup>18</sup> The highest percentage availability was only 88%.

their efficiency. However, we calculated the 84% figure after already making allowances for the effect of the heat (Appendix 2).

**Table 2: Available Capacity/Installed Capacity Ratio on July 2, 1100 hrs**

Company [A]	Former Name [B]	Installed Capacity, Temperature Adjusted (MW) [C]	Available Capacity, Temperature Adjusted (MW) [D]	Ratio (%) [D]/[C]
<b>Total</b>		<b>13,884</b>	<b>12,100</b>	<b>87%</b>

Notes and Sources:

Accidental outages of around 15% appear extraordinary. We estimated the probability of such an aggregate level of outages, given estimates of accidental outage rates for each generating unit in the Netherlands. Our calculations show that a sustained outage of 1,784 MW could be expected at least once per year.<sup>19</sup> This figure suffices to demonstrate that similar episodes could be expected to recur naturally in the future (Appendix 2).

*We believe that price spikes will continue to affect the Dutch electricity market due to the market's small size and vulnerability to simultaneous and unexpected changes in supply conditions.* For a given reserve margin, the Netherlands has lower reliability than a larger market because it has a few number of large generating units.<sup>20</sup> A larger market naturally has more generating units ranging in size, causing its system-wide outage rate to be less likely to deviate significantly from the average of the outage rates for each unit. This is comparable to diversifying risk: buying a portfolio of many types of stock causes the portfolio to move with the market index while buying only a few stocks typically results in price movements that can deviate largely from the market index. We have not calculated the likelihood of outages in Belgium, but the small size of the Belgian market and its relatively small number of large nuclear units suggest that outages there are also likely. Such outages can affect the Dutch market by creating a strong demand for Dutch generation. We conclude that the Dutch market is inherently more susceptible to outage problems than markets with relatively more generating plants. We therefore support TenneT's decision to increase interconnector capacity. Interconnectors are generally more reliable than generating units, and increased interconnection with larger power markets will support the reliability of the Dutch market. Although in theory, equivalent reliability

<sup>19</sup> Our analysis, treating each hour as statistically independent, concluded that such outages could be expected 9% of the time. A system "outage period" as witnessed over two weeks in June or July could be expected once a year.

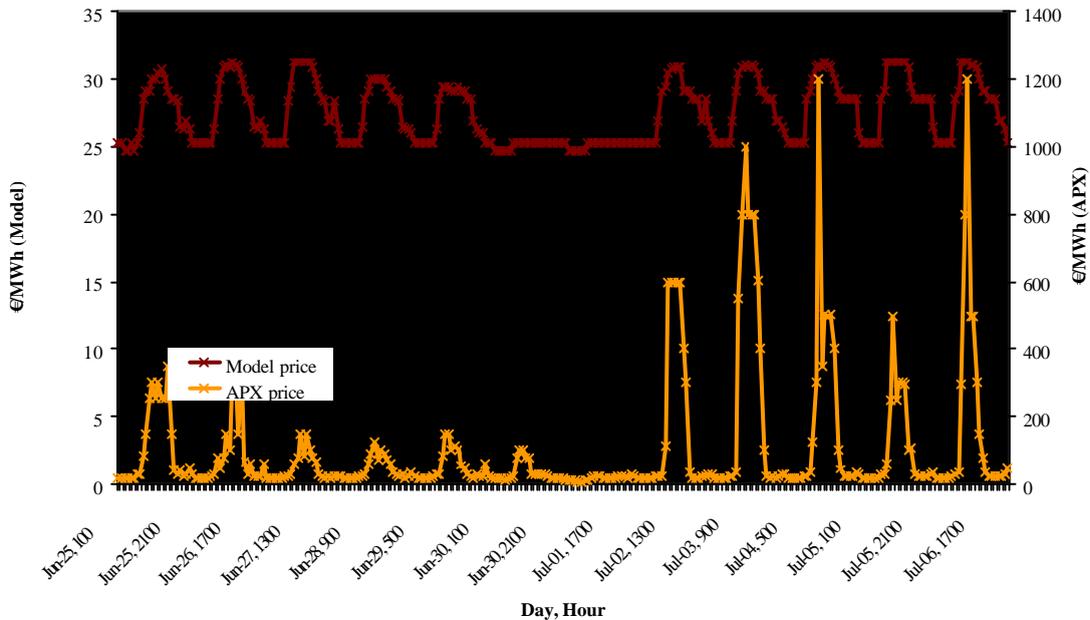
<sup>20</sup> In theory, even a small market could have a large number of generating units, if each unit were small. However, about 80% of Dutch installed capacity consists of plants sized 300 MW or larger.

could be added through the construction of domestic generating capacity, there is no indication that TenneT's plans will deter new plant construction that would have provided equivalent reliability.

### 3.3. Simulation of APX Price Spikes

In theory, defects in the APX market could also have caused the price spikes. To check this possibility, we modelled the Dutch electricity market in June and July 2001 given information on the actual level of outages experienced. Our model predicts despatch of high-cost units during the periods where actual spikes were witnessed on the APX. Figure 2 shows the model's predicted prices and APX prices. Our model did not attempt to predict the market price of electricity given the scarcity of available plant. Instead, it simply reported the marginal cost of the most expensive unit that was necessary to meet demand. Nevertheless, our model clearly predicted peaks on roughly the same hour of each day that the APX price spikes occurred.

Figure 2: Comparison of Model and APX prices



[D1]

Although the price spikes were quite high, it makes economic sense for prices to approach the “value of lost load” (VOLL) at times of scarcity. VOLL refers to the costs that would be incurred if a situation arises where “black-out economics” apply, which refers to a state where all available market supplies approach exhaustion. Such a state can arise before a black-out is actually threatened, because even if demand exceeds the capability of all available resources on the balancing market, TenneT has access to emergency reserves and can curtail interconnector flows if necessary. TenneT's emergency powers do not affect the market price of power.

At times of scarcity, no generator feels the need to bid a price commensurate with its operating costs, since demand is so great that all generators will be needed. Market prices

naturally approach VOLL at such times, since only bids that exceed VOLL will deter demand. Experience indicates that VOLL can exceed 3,000 €/MWh.<sup>21</sup> Although our model confirmed that 1,000 MW was available to meet demand during the price spike period, in the absence of perfect information it was reasonable for market participants to believe that black-out economics could apply. It would not have taken much uncertainty for market participants to estimate that only 200 MW might be available in the market, which is less than the size of many units. Had market information been more transparent, concerns would have been less and prices may not have risen so high as to approximate the VOLL. One of our recommendations, therefore, is to improve the APX market’s transparency.

We also compared the day-ahead peak APX hourly prices to the day-ahead peak Over-the-Counter (OTC) prices in the Netherlands during the price spike period. When two markets trade a similar product, price comparisons help determine whether one of the markets may have unusual features that distort its performance. Table 3 shows both the APX and OTC day-ahead prices as published in Platts’ European Power Daily. The OTC peak price mirrored changes in the APX peak price, further confirming that the Dutch price spikes were caused by outages rather than any defect on the APX market.

**Table 3: Comparison of APX and OTC NL Peak Prices**

Date [1]	APX Day-ahead price, peak period (€/MWh) [2]	NL OTC Day-ahead Price, peak period (€/MWh) [3]
25-Jun-01	110	68
26-Jun-01	n/a	n/a
02-Jul-01	376	213
03-Jul-01	262	363
04-Jul-01	147	200
05-Jul-01	252	198
06-Jul-01	n/a	n/a

Notes and Sources:

[2]-[3]: Platts European Power Daily.

## 4. Market Structure

Market structure refers to the distribution of available generating capacity. The least competitive structure is where one company owns 100% of the capacity, and the most

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<sup>21</sup> Capacity payments in the England & Wales pool were designed around an assumed VOLL of 2,000 £/Mwh, and prices at times of scarcity in Australia have been even higher. Newbery, David “Pool Reform and Competition in Electricity” in Beesley, M.E. ed. *Regulating Utilities: Understanding the Issues*, pp. 139-141.

competitive structure involves a different owner for every unit. Four large generators in the Netherlands collectively own approximately two thirds of total installed capacity.<sup>22</sup> However, experience has indicated that these aggregate figures can be extremely misleading because they ignore distinct relevant markets at “baseload” and “peak” periods. For example, in the United Kingdom, the two largest generators controlled over 90% of the peak plants since 1991, enabling them to set the system marginal price over 90% of the time.<sup>23</sup> While the baseload market was much less concentrated, this created serious market power problems in the peak market.

We therefore determined the markets for baseload and peak generating capacity in the Netherlands, and analysed the concentration of ownership in each market. We defined the baseload and peak markets by examining the Dutch aggregate supply curve. In Figure 3, each dot along the supply curve notes a separate generation plant.<sup>24</sup> From Figure 3, it is clear that the Dutch market experiences several “jumps” in its variable supply costs (at about 18, 27 and 32 €/MWh). After examining the supply curve and mix of generation assets, we defined the baseload market as including all generators to the left of the dividing line or generators with variable costs below 27 €/MWh. Similarly, the peak market includes those plants with variable costs equal to or greater than 27 €/MWh plus all import capacity. We note that this definition of “baseload” and “peak” markets does not necessarily coincide with common use of the terms. Market participants think of peak plant as running principally during weekdays. In economic terms, we call every unit a peak unit if its costs approximate those of the units that set prices during weekdays. However, a peak unit may run even more frequently than weekdays, depending on demand levels. In all cases, we included interconnector capacity in the peak market because day-ahead interconnector prices were well above the maximum variable cost of domestic generating capacity during the peak price spike hours.

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<sup>22</sup> Our model includes 12,600 MW of power from Electrabel (formerly EPON), Essent (formerly EPZ), Reliant (formerly UNA), and Eon Benelux (formerly EZH). Some of these companies, in particular Essent, control capacity in units of less than 60 MW. Total Dutch capacity is about 20,000 MW.

<sup>23</sup> *Decision on a Monopolies and Mergers Commission Reference* (Feb. 1994), p. 23.

<sup>24</sup> Whilst interconnector capacity is used in our analysis of peak concentration, it has been omitted from this graph. The mothballed plants – – – – – are included in the HHI analysis, since they could potentially generate energy.



**Table 4: Baseload Market HHI Summary**

Day, Hour [A]	Price (€/MWh) [B]	HHI - Baseload NL Output (Variable Cost<€/MWh) [C]	HHI - Baseload NL Capacity (Variable Cost<€/MWh) [D]
June 25, 17	350	2,175	2,044
June 26, 14	300	2,162	2,044
July 2, 11	600	2,212	2,044
July 3, 12	1,000	2,197	2,044
July 4, 12	1,201	2,165	2,044
July 5, 12	495	2,185	2,044
July 6, 12	1,200	2,163	2,044

Notes and Sources:

[A]-[B]: TenneT

[C]-[D]: See Appendix 3.

**Table 5: Peak Market HHI Summary**

Day, Hour [A]	Price (€/MWh) [B]	HHI - Peak NL Output (Variable Cost>€/MWh) Plus Nominated Imports [C]	HHI - Peak NL Capacity (Variable Cost>€/MWh) Plus Import Capacity [D]
June 25, 17	350	1,426	2,084
June 26, 14	300	1,540	1,902
July 2, 11	600	1,593	2,127
July 3, 12	1,000	1,623	2,081
July 4, 12	1,201	1,572	2,106
July 5, 12	495	1,599	2,115
July 6, 12	1,200	1,649	2,110

Notes and Sources:

[A]-[B]: TenneT

[C]-[D]: See Appendix 3.

Although no single HHI figure is universally accepted as the dividing line between a competitive market and a highly concentrated one, figures of up to 2,000 have been cited

by economists in relation to electricity generation markets.<sup>26</sup> The highest peak HHI for the Netherlands is about 2,100. The peak HHI is kept low by the cap on the ownership of interconnector capacity: no generator is allowed to control more than 400 MW.<sup>27</sup> We also note that the concentration of available capacity was slightly lower than the concentration of installed capacity. This suggests that the outages did not aggravate market power.

The market concentration is not so high as to warrant calls for the divestiture of generating assets as we have made elsewhere. Nor would we propose lowering the cap on ownership of interconnector capacity. Additionally, our analysis tends to exaggerate market concentration, particularly baseload concentration, because it focuses on units greater than 60 MW. If we had included the 5,000 MW of decentralised plants excluded from our analysis, the HHI might have been lower. However, we do not have sufficient data to account for these units. In particular, we do not have sufficient evidence to account for the control that the four large generators have over these units.

The evidence concerning outages, the somewhat high concentration in the peak market, and the much higher concentration of the baseload market together prompt us to focus instead on a key aspect of market conduct: whether deliberate withdrawals of capacity may have caused the price spikes rather than accidental outages.

## 5. Market Conduct

Our market conduct analysis examines the behaviour of market participants. We consider whether the large plant outages witnessed in the Netherlands during the price spike period might reflect deliberate attempts by generators to withhold plant capacity. We also examine whether some of the high bids into the APX might reflect the costs that a gas-fired generator would have incurred by running imbalances on the Gasunie system.

### 5.1. “Artificial” Outages

Some generators experienced outages of up to 26% during the price spike period (Appendix 2). -----  
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<sup>26</sup> Professor Littlechild, the former UK electricity regulator, has cited a HHI of 1,750 as the cut-off point between a moderately and a highly concentrated market. (Littlechild, S.C., “Competition and Change”, Wilson Campbell Memorial Lecture, 10 March, 1997.) A similar measure is applied by the US Department of Justice, which considers markets with a HHI of 1,800 or more to be concentrated. Transactions that increase the HHI by more than 100 points in these markets raise antitrust concerns under the Horizontal Merger Guidelines issued by the U.S. Department of Justice and the Federal Trade Commission. When Professors Newbery and Green discussed competition in the UK electricity spot market in 1992, they estimated that a HHI of 2,000 could eliminate most of the inefficiencies of a duopoly in generation. (Green, Richard J. and Newbery, David M., “Competition in the British Electricity Spot Market”, *Journal of Political Economy*, Vol. 100, No.5 (1992), p.95.)

<sup>27</sup> Article 5.6.11.3 of DTe’s Technical Standards limits each participants’ total nominated capacity, summed over the connections and after balancing the import and export, to 400 MW.



section 6.1 below, even adding in a generous estimate of start-up costs cannot raise the total variable cost high enough to explain the spikes.

We therefore consider whether an additional “scarcity premium” could have raised generators’ supply bids and contributed to the APX price spikes. In competitive markets, the “scarcity” of peak capacity can provoke large price spikes even in the absence of market power problems. For example, an oil plant that only runs 20 hours a year can be expected to charge prices that would significantly exceed variable operating costs. If the market were in equilibrium, the oil plant would charge sufficiently high prices during its 20 hours of operation to recover its entire average costs for the whole year. We examined how average costs compared to APX prices. We concluded that recent APX prices were not so high as to provide excessive returns on peak plant.

### **6.1. Start-up Costs**

In a competitive market, high start-up costs would cause peak plants to raise their APX bid prices. If peak plants expect to run only an hour at a time, they must bid a sufficient amount to recover at least their short-run variable and start-up costs. We estimated start-up costs for an open-cycle gas turbine (OCGT) plant, assuming the plant only operates for one hour at a time. Our approach maximises the potential impact of start-up costs because it assumes the generator must recover all costs in a minimum amount of time.

Start-up costs for the OCGT plant amount to at least 50 €/MWh for one hour. Even if the most expensive generators bid into the APX market to recover their marginal and start-up costs in one hour, their total bid would remain in the range of 100 €/MWh. Bids of 100 €/MWh do not fully explain the 600 to 1,200 €/MWh price spikes witnessed in June and July 2001. We therefore conclude that start-up costs were not a significant contributor to the price spikes.

### **6.2. Average Costs**

We determined whether the APX price spikes allowed either a Combined Cycle Gas Turbine (CCGT) or an OCGT to earn excessive returns. Specifically, we compared the annualised fixed costs of a CCGT and OCGT to the annualised profits the plants would have made given the APX prices through July 15<sup>th</sup>, 2001. We chose a CCGT and OCGT plant because they are representative of peak plants. They generate fewer hours of the year and must therefore recover most of their costs during the higher-priced periods.

Neither the CCGT nor the OCGT would have earned excessive returns over the year. Column [C] in Table 6 shows that, if the CCGT’s profits from January 1 through July 15<sup>th</sup> were annualised over the year, it would earn about 86,000 €MW while it required over 100,000 €MW to break even (Column [D]). Similarly, the OCGT would earn about 48,000 €MW while its break-even profit is closer to 52,000 €MW. We calculate Column [B] by assuming that the CCGT and OCGT plants only operate during those hours when the APX price is greater than their variable generating costs.

**Table 6: Estimated Income for New Plants**

Plant type [A]	Estimated Profits (€MW), 1st Jan - 15th July [B]	Annualised Profits (€MW), 1st Jan - 15th July [C]	Break-even operating profit (€MW) [D]
Advanced CCGT [1]	47,825	86,084	102,563
Advanced OCGT [2]	26,632	47,938	51,619

Notes and Sources:

[B]: Based on current 2001 data. Plants are assumed to despatch if their despatch costs are less than the market price in any given hour. Adjusted to account for availability factors of 91% for CCGT's, and 95% for OCGT's.

[C] = [B] x (12/6.5)

Table 6 indicates that the “scarcity premium” earned by CCGT and OCGT plants during the price spikes did not involve excessive returns. If the CCGT and OCGT had earned excessive returns, we might conclude that market power was a serious problem. Instead, APX prices from January 1<sup>st</sup> to July 15<sup>th</sup> *including* the price spikes have only been high enough for these generators to earn a fair return.

## 7. Recommendations

We recommend several changes to the Dutch market. Our recommendations are designed to increase market efficiency, mitigate potential market power abuse, and prevent large outages from causing price spikes in the future.

### 7.1. Outages

*We strongly recommend that the Netherlands and Belgium establish separate, but closely co-ordinated, maintenance schedules.* Although the price spikes were caused by unplanned rather than planned outages, a co-ordinated planned maintenance programme would help the Netherlands minimise its risk of large unforeseen outages and allow TenneT to remedy such outages more quickly and easily.

The Dutch power system is particularly vulnerable to outages because it comprises a relatively small number of large generating units, and has limited interconnection with foreign generators. It is therefore crucial that the Netherlands diversify its risk of supply shortages over a larger system by co-ordinating plant outages with Belgium. Co-ordination implies that more Belgian generators will be available when Dutch plants are down and *vice versa*. If the Netherlands does experience sudden outages it should have a greater chance of relying upon surplus generation sources in Belgium.

*We recommend that the co-ordinated programmes require generators to provide TSOs advance notice of maintenance schedules, restrict the ability of generators to revise maintenance plans in the short-term, and allow either TSOs or governments to delay or veto specific maintenance plans.* If TSOs anticipate that large unplanned outages may

occur due to unusually high temperatures or other factors, they should have the authority to delay or cancel certain generator's planned maintenance to minimise the chance of inadequate supply. We would not expect Elia or TenneT to cancel or delay maintenance for several months, but to postpone it until the threat of outages has passed. During the summer of 2001, the price spikes extended over a two-week period, suggesting that two weeks could be a reasonable period for delaying planned outages.

*Finally, we recommend that generators be required to compile records concerning any unplanned outages, and to submit them to their TSO on a regular basis.* The TSOs and regulators should have the responsibility and authority for investigating unplanned outages. We recommend that TenneT or the government develop a formal procedure for monitoring potential outage abuse.

## **7.2. Transparency**

We have analysed the transparency of the market, and determined that less information is published in the Netherlands than in most liberalised power markets. For example, information concerning total system load is not yet collected or published. TenneT knows the total demand on the Dutch high-voltage transmission system, but does not receive information concerning the generation and consumption of all the distribution systems. TenneT can use its skills and expertise to derive reasonable estimates of demand, but we doubt that all market participants have similar abilities. Information on demand is published in Australia, Scandinavia, Spain, the United Kingdom, and the United States.

Table 7 compares the available information in the Netherlands with the information available in several other power markets, including England & Wales, California, PJM<sup>29</sup> and Australia. The Netherlands is the only country that currently publishes only one of the four categories of information listed in Table 7. All the others currently publish at least three of the four categories of information. The previous day-ahead market in California (the California Power Exchange) published only two of the categories, but the California ISO has since replaced it and now publishes more information.

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<sup>29</sup> PJM is the name of the centralised power pool that covers the states of Pennsylvania, New Jersey and Maryland. It is one of the largest centralised power pools in the world.

**Table 7: Information Disclosed in Electricity Markets**

Country	Market	Load	Availability	Output	Aggregated Bids
Netherlands	APX	N	N	N	Y
Australia	NEM	Y	N	Y	Y
Scandinavia	Nordpool	Y	Y	N	Y
Spain	Omel	Y	N	Y <sup>†</sup>	Y <sup>†</sup>
	Red Electrica	Y	Y	Y <sup>†</sup>	Y <sup>†</sup>
UK	Pool	Y	Y	Y	Y
	NETA	Y	Y	N	Y
USA	PJM	Y	Y	N	Y
	Cal PX	Y	N	N	Y <sup>†</sup>
	Ca ISO	Y	Y	N	Y <sup>†</sup>

Notes:

† Publishes Details After a 3 Month Period

We have considered the potential economic costs and benefits of publishing more information than is currently available in the Netherlands. One key benefit is placing all market participants on a level playing field. In the Dutch electricity market the four large generators have inherited significant knowledge and expertise from their history of activities, which includes previous co-operation with Sep. It is more difficult for traders and potential entrants to acquire comparable knowledge. Competition is not enhanced when some companies have significantly greater knowledge than others, and the knowledge is not the result of deliberate investment in understanding the new power market, but simply the product of historical circumstances.

Experience and common sense also indicate that transparency is critical for promoting liquidity. Electricity “forward” contracts of one year or more are common.<sup>30</sup> The value of forward contracts depends on projected market prices. In the absence of transparency, market participants will be unsure about the future development of market prices. The large generators will have an inherent advantage in this respect. Customers will still be interested in signing forward contracts to protect themselves from the volatility of short-term prices. However, in the absence of sufficient market information, customers will hesitate to adjust their contractual positions frequently. Customers will recognise that

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<sup>30</sup> They are called “forward” contracts because they look forward to the delivery of electricity some time after the contract has been signed.

each forward trade places them at a disadvantage with respect to the established generators who have better knowledge of future market developments.

Timely information disclosure can also improve short-term efficiency, as decisions concerning consumption or the despatch of particular units may depend on projected short-term prices. Information disclosure can improve long-run efficiency by promoting forward market liquidity. Forward market liquidity improves the market signals that govern any decision with important temporal components, such as scheduling plant maintenance, capacity additions and retirements, or making long-term fuel procurement commitments. For example, a generator may wonder whether to schedule a nuclear plant's maintenance in September or October. The generator will obviously prefer to schedule maintenance during the month when prices are lowest, and to generate during the month when prices are highest. If a liquid forward market exists, the generator's decision can be informed by a comparison of the forward prices for delivery in each month. If the generator is averse to risk, then the generator can sign a contract on the forward market with a trader to protect against an incorrectly timed decision.

By establishing a level playing field, and improving both liquidity and efficiency, prompt information disclosure can also reduce entry costs. The decision to build a power plant can be informed by examining forward prices in liquid markets. Plant construction is often supported by long-term forward contracts with consumers. Such contracts are easier to sign in the presence of a liquid forward market. More generally, information disclosure can help potential entrants assess the fundamentals of supply and demand in a market and the extent of market power.

An additional benefit of information disclosure involves market monitoring. Although a regulatory agency may continuously examine the market for evidence of market power abuse, experience has indicated that the input of market participants is important. Consumers, entrants, traders and smaller producers all can have incentives to provide input to improve market monitoring.

We acknowledge a potentially serious cost to greater information disclosure. Information disclosure can facilitate successful collusion. Collusive agreements are often vulnerable to "cheating" by their participants. If four companies agree to maintain high prices, any one of them might be able to increase profits if it breaks the agreement, charges lower prices, and takes market share from the other three while they continue to abide by the agreement. To sustain a collusive agreement, its proponents must therefore be able to detect cheating and respond with rapid punishment. If the collusive price is 40 €/MWh while costs are only 20 €/MWh, punishment could consist of a "price war" that lowers prices to 10 €/MWh and forces market participants to incur losses until the cheater reverts to the originally agreed bid of 40 €/MWh.

A common concern of economists is that the disclosure of excessive information can facilitate the detection of cheating and permit rapid responses with price wars to enforce a collusive agreement. This concern has prompted authorities in several power markets to delay the release of information. For example, the California Power Exchange and PJM each delay the release of certain market information by several months.

Collusion is most likely to occur when the industry structure lies between the extremes of pure competition and pure monopoly. Even with ample information disclosure, collusion would be difficult to sustain in a market where no generator has a significant market share. When one large player dominates an industry, market power is indeed a concern but the risk of collusion fades. A dominant firm can exercise its market power without the need to communicate with rivals. However, the market structure of the Netherlands lies between the extremes of perfect competition and pure monopoly, and is within the range where collusion is a serious threat.

Even if collusion is a concern, alone it cannot justify the suppression of information from the market. A responsible analysis must focus on the incremental likelihood of collusion that may arise from publishing information. Economic theory and evidence indicate that companies can detect cheating on a collusive agreement, even if each company does not know the level of production and the prices charged by rivals. As long as the colluders have reasonable estimates of industry demand, they can detect cheating by observing significant reductions in their market shares. The underlying theory has been developed by professors Green and Porter, and Professor Porter has found supporting evidence in his analysis of railroads in the United States.<sup>31</sup>

Independent of economic theory and evidence, common sense suggests that publication will only increase the likelihood of collusion if companies are unlikely to obtain the relevant information otherwise. In the Netherlands, concerns with collusion are associated with the existence of four large generators who collectively own a significant percentage of available capacity. These generators may inevitably possess certain types of information that are relevant to collusion. We do not imply that the generators in the Netherlands are likely to collude. We only emphasise that, in the hypothetical case that they did, increased transparency could not aggravate the problem unless it involved information that they did not already have.

We conclude that the optimal approach is to review certain key categories of information that could significantly increase the transparency of the market. For each category of information, we recommend publication unless two conditions apply: a) the four large generators would not likely obtain the information otherwise, and b) the information could facilitate the detection of “cheating” on a potential collusive agreement.

We have analysed the potential release of information concerning demand, availability, maintenance schedules, the output of each generation unit, and contracts. TenneT has information concerning the hourly demand on its system, but does not receive routine information concerning the hourly demand on the distribution systems or by companies that consume part of their electricity from on-site co-generation units. Nevertheless, TenneT has been able to develop reasonable estimates of demand based on

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<sup>31</sup> “Non-Cooperative Collusion Under Imperfect Price Information,” *Econometrica*, Vol. 52 (1984), pp. 87-100 (for the theory), and Porter RH, “A Study of Cartel Stability: The Joint Executive Committee, 1880-1886,” Vol. 29, pp. 313-338 (identifying evidence).

its experience in the industry. Sep previously collected demand information. We have reason to believe that the four large generators should also have the knowledge and expertise to derive reasonable estimates of demand. We therefore find it difficult to believe that publishing this information would significantly enhance the likelihood of successful collusion. We are less confident that all traders or consumers can estimate demand reasonably. We therefore perceive significant benefits to publishing demand information. *We recommend the adoption of a standard definition of hourly demand, and the publication of the information from all the relevant market participants.* TenneT could then aggregate the demand information for the entire country and publish it to increase transparency. To provide a complete picture of the demand served by domestic capacity, *we also recommend publication of the actual flows over each interconnector with Belgium and Germany.* TenneT is already publishing with a 15-minute delay the net system exchange on its interconnectors.

Our analysis has shown that information on availability is extremely important for understanding market dynamics. This information proved difficult to collect because there is no rule requiring generators to indicate the availability of each unit. Conceivably, a collusive agreement could require generators to declare falsely that particular units were unavailable. Publication of actual availability information could therefore facilitate collusion. However, our analysis in this case indicated that well-informed market participants could use informal channels to collect information concerning availability. We also note that a conspiracy that focuses on plant availability is just one of several possible ways of colluding—generators could simply agree to set prices explicitly. Companies have shown remarkable ingenuity in deriving ways to collude, even co-ordinating bids with the phases of the moon.<sup>32</sup> We therefore doubt that co-ordinating the availability of generating plant would prove critical for collusion to succeed. We recommended above other measures that would allow DTe to detect the manipulation of availability. Generators should be required to keep records of any technical problems that impede availability, and DTe should have the authority to investigate these records or to inspect generating units on site. In light of these measures and the other factors cited above, we conclude *that generators should be required to provide information concerning the availability of each unit, which should be made available to all market participants.*

Maintenance schedules are currently not published in the Netherlands. We view this issue as similar to availability, although perhaps even well-informed generators would not be able to anticipate each other's maintenance schedules in the absence of collusion. However, our recommended safeguards against the manipulation of maintenance schedules are even stronger than the safeguards concerning availability. In addition to investigating changes in maintenance schedules, we recommend that DTe or TenneT be allowed to veto proposed maintenance schedules. *We therefore recommend the publication of maintenance schedules.*

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<sup>32</sup> Herling, John, *The Great Price Conspiracy* (Washington: Robert B. Luce Inc.), 1962.

Currently, there is no rule in the Netherlands requiring each generating unit to provide information concerning its actual despatch. Although some companies provide TenneT this information, others do not. A historical analysis of output by each generator is important for understanding the market. However, disclosing the output of each generating unit raises the greatest concerns regarding collusion. Even well-informed market participants will find this information more difficult to obtain through informal channels than information on availability. Furthermore, the output of each unit facilitates the detection of cheating, no matter what the form of a collusive agreement. *We conclude that the publication of generator despatch information should be delayed significantly, so that it will not be used to detect and punish cheating on a collusive agreement.*

Some power pools have delayed the publication of sensitive information by three months, while others have delayed it by six months. We do not believe that the value of such information would be compromised seriously by a six-month delay in publication. Electricity market prices depend significantly on seasonal factors. Temperatures and prices in the spring and autumn are often similar, but a delay of six months would still allow market participants each autumn to make some comparisons with the previous spring, and with the previous autumn. At the same time, a six-month delay could be expected to complicate significantly the enforcement of a collusive agreement. *We conclude that six months is a reasonable delay period.*

### **7.3. Declaring Positions**

*We recommend that generators declare their year-ahead contractual position to the DTe. The DTe should then publish the data in an aggregated form to protect anonymity, and also produce ex-post HHI indices of available non-contracted capacity.* We believe that the publication of this information will decrease any information asymmetries that, combined with the existence of forward contracts,<sup>33</sup> provide generators with incentives for spot market manipulation above those created by market power.

Generators with market power have natural incentives to manipulate spot prices so as to maximise their profits in the spot market, at times when they are not fully contracted forward. When the generator is “long” on power (has not signed contracts in excess of its generating capacity) its natural incentive is to raise prices. If the generator is “short” on power (has contracted to generate more than possible with its available capacity) it becomes a consumer in the spot market, purchasing energy to satisfy its contractual commitments. The generator then has an incentive to lower market prices, and will therefore submit lower bids.<sup>34</sup> This type of behaviour has been confirmed in the electricity

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<sup>33</sup> Forward contracts can consist either of traditional bilateral agreements, or “contracts for difference” (CfD’s). CfD’s consist of agreements between generators and suppliers to compensate each other for differences between the market-clearing price and an agreed price for a given amount of power at a given time.

<sup>34</sup> If generators did not have market power, they would bid in at their marginal costs, since if the spot price was lower, they would be better off purchasing in the spot market than generating their own power.

pool of England & Wales.<sup>35</sup> A generator will be more successful at manipulating prices if its long and short positions are concealed from consumers.

In addition to these short-term considerations, generators can have additional incentives to manipulate spot market prices. When major forward contracts are up for renewal, generators may wish to manipulate prices so as to affect consumer expectations of future prices and future price volatility, effectively fooling them into signing inflated forward contracts.<sup>36</sup>

These examples presume the existence of market power. Generators cannot manipulate prices in a perfectly competitive market. The examples also involve the abuse of information asymmetries. Increasing transparency to redress these asymmetries can therefore mitigate market power abuse.

Market manipulation inevitably presents some risk of detection and punishment. Generators would logically balance the potential benefits and costs of manipulation, and engage in such behaviour only when the incentives are high, as when a significant number of futures contracts are up for renewal. Publication of predicted uncontracted capacity would therefore increase the ability of market participants to anticipate generator incentives. Market participants would develop a better ability to predict forward prices, which would increase the efficiency of forward markets. Publication would also facilitate market monitoring by the regulator and market participants. *We recommend the ex-ante publication of predicted available un-contracted capacity.*<sup>37</sup>

*We also recommend the ex-post publication of observed HHI's of available un-contracted capacity.*<sup>38</sup> HHI indices of available non-contracted capacity should be published with a delay, allowing people to analyse market episodes in retrospect and determine if market power, rather than fundamentals, explained price patterns. A high HHI might indicate whether the uncontracted capacity is concentrated in such a small group of firms as to exacerbate market power problems. Our recommendations should help market participants distinguish changes in the fundamentals of energy production from changes in market power, and should decrease the current information asymmetry between generators and suppliers.

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<sup>35</sup> 'A report on generator market power in the electricity market of England and Wales'. Appendix 1.1. The Brattle Group, 1997.

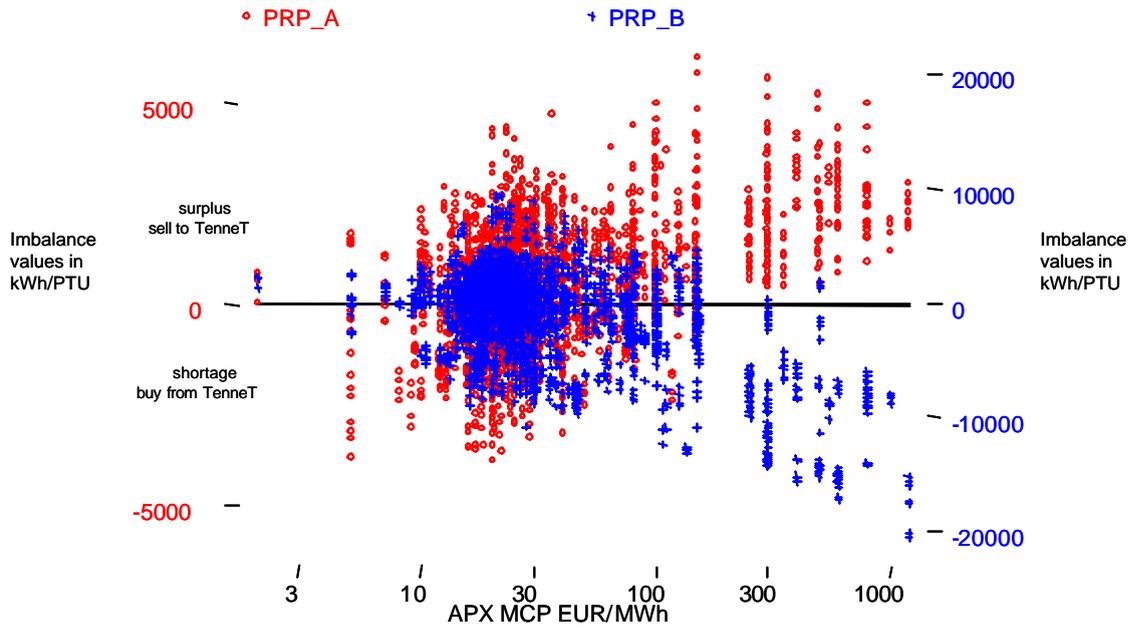
<sup>36</sup> A forward contract can be thought of as tariff in two parts: one consisting of the expected price, increased by raising the mean spot price; and another consisting of a risk premium, increased by raising the variance of the spot price.

<sup>37</sup> Each firm's predicted un-contracted capacity = nameplate capacity + purchase contracts – supply contracts – planned maintenance. Year-ahead figures should be supplied to DTe periodically, who should add them up to give total un-contracted capacity, and publish them.

<sup>38</sup> We do not believe the publication of such information would compromise confidentiality in any way. Aggregation of contractual positions will provide anonymity in much the same way as the aggregation of the data in the publication of the APX bid curves.



**Figure 4: Behaviour of Balancing Market Participants**



We see little economic logic to persistently withholding reserves from the balancing market, and we note that participation is in any event obligatory for units larger than 60 MW. When a generator withholds uncontracted capacity from the balancing market, it incurs an “opportunity cost”: the capacity could have been sold profitably in the market. Even at low prices, the profits could be substantial. Although withholding capacity would allow a generator to avoid imbalance charges from going short, the behaviour that we have seen suggests that in some cases the opportunity costs of withheld reserves should more than offset the avoided imbalance charges.

The behaviour that we observe may be temporary, if participants are not yet be accustomed to the new balancing market. Greater participation would increase market liquidity and potentially help reduce APX price spikes. We expect that as parties learn the new balancing system better, they may become more willing to offer reserves. *We therefore recommend that TenneT offer seminars for market participants to describe the behaviour witnessed on the balancing market, so that parties can see the patterns, understand the implications, and react. This should help accelerate the development of an active and more liquid balancing market. We also recommend that TenneT review the balancing rules to ensure that they do not discourage inefficient participation in the market.*

## 7.6. Single Benelux Market

The formation of a “single Benelux market” is being considered.<sup>39</sup> Fundamentally, the existence of a single market depends on economic criteria, and in particular on whether the Dutch-Belgian interconnection capacity is a binding constraint on cross-border trade. However, institutional changes of the kind proposed can nonetheless have significant impact. We advocate several reforms for furthering the goal of improved market integration in Benelux. *First, we recommend that Belgium adopt access rules similar to those in the Netherlands. Second, we suggest greater co-operation between DTe and CREG and between TenneT and Elia to ensure effective regulation and market monitoring.*

Recognising that events in Belgium impact heavily on the Netherlands and that the markets cannot be considered autonomous, we recommend greater harmonisation, co-operation and information exchange between the Dutch and Belgian authorities. *We support moves to harmonise access rules and grid codes. We believe that DTe, CREG, TenneT, and Elia should each have current data readily available on planned outages, forced outages, despatch, and load. Access to such information would allow the respective regulators and TSOs to respond to market events in an informed and effective manner. Additionally, it would enable them to work together to monitor and mitigate unexpected market events and to detect potential market power abuse.* -----

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Although we advocate greater market integration and co-operation, *we urge caution before changing the current system of allocating interconnector transmission rights.* The existing interconnector auctions provide price transparency and signals for further investment, and allocate interconnector costs directly to users. Additionally, they impose restrictions on market participants by limiting the amount of net capacity each participant can buy. Such restrictions mitigate market power concerns and are likely to be harder to implement in a single Benelux market.

## 7.7. APX Price Cap

Currently, the APX limits day-ahead bid prices to no more than the highest imbalance price as published by TenneT.<sup>40</sup> Such a cap could inadvertently serve as a focal point for

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<sup>39</sup> Such a programme would include measures to co-ordinate access rules and other TSO systems and procedures, and potentially changes to the treatment of the Belgium-Netherlands interconnector (e.g., the introduction of a single pool with market-splitting, or the use of co-ordinated redespach by TSOs to avoid congestion, with the costs “socialised” via inclusion in transmission tariffs).

<sup>40</sup> APX website: <http://www.apx.nl/marketresults.html>.

nervous bidders, or for collusion. Additionally, it could facilitate bidding strategies by electricity importers that effectively by-pass the APX.

The Dutch Network Code requires market participants importing power across the interconnectors to sell all their imported power into the APX. However, an importer can introduce the imported power into the APX and simultaneously “repurchase” it.<sup>41</sup> This type of trade allows the importer to retain control over the imported power, perhaps to supply end-users directly. Market participants can use the APX maximum bid price to ensure their repurchase of desired import capacity. For instance, a trader could bid to supply capacity at 0 €/MWh and simultaneously bid to purchase the same amount at the maximum price. Repurchase would be guaranteed. Because the market participant would effectively be buying from itself, the net cost of such a transaction would only be the APX transaction fee. Such trades do not provide accurate price signals to the Dutch electricity market and reduce the amount of capacity that is competitively available.

The APX price cap artificially provides bidders with a shared expectation regarding the market’s behaviour, an expectation that may influence bidders. Instead of developing independent, competitive bidding strategies, bidders may structure their strategy around the maximum price. Similarly, colluding generators may use the maximum price to raise the APX clearing price tacitly. *We recommend that the APX eliminate its bid price cap.*

### **7.8. Interconnector Capacity Cap**

To mitigate high peak market concentration, *we recommend the introduction of a company-specific import cap.* The import cap should distinguish between incumbents and entrants and be responsive to changes in total interconnector capacity. The existing cap ensures that no company dominates the interconnector capacity market. However, it may prove too strict to some market participants and too generous to others. *If some firms already control a significant amount of peak capacity independent of the interconnectors, it would make sense to constrain their purchases more than the purchases of others.*

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<sup>41</sup> We say that a party “repurchases” 1MWh when it simultaneously sells 1MWh of power into the APX, and purchases 1MWh of power from the APX.

**Table 8: Total Peaking Plant Capacity (July 4)**

Company [A]	Total peaking plant capacity (MW) [B]	Interconnector cap [C]
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Notes and Sources:

### 7.9. Interruptible Capacity

Offering interruptible interconnector capacity would maximise interconnector use and promote efficient transactions between the Netherlands, Belgium, and Germany. Interruptible capacity can be offered in two different ways. The first approach entails customers booking a fixed amount of firm capacity *and* an additional amount of interruptible capacity if they wish. The firm capacity would always be available to a customer whether or not it is used, but TenneT would have the right to scale back the interruptible capacity at short notice should the need arise. TenneT would not be responsible for the costs or damages from any interruptions. In an auction, the price of the interruptible capacity would automatically be lower than the price of firm capacity, sufficiently to compensate for the perceived likelihood and cost of interruption. The advantage of such a programme would be enabling TenneT to sell more total interconnector capacity, which could lead to greater competition and liquidity. *We therefore recommend that TenneT give this approach serious consideration.*

The second approach involves customers booking only firm daily capacity and TenneT retaining the right to offer any unused portion of this capacity on short notice to other customers. TenneT could, for example, inform customers that any portion of their capacity not specified for use through E-programmes or in the balancing market some hours in advance would be offered to other customers. The value of this approach is less clear, however, because TenneT is already considering intra-day trading of capacity. In practice, this form of interruptible capacity would replicate some aspects of intra-day capacity trading. There is less reason for TenneT to implement and operate a scheme when market forces alone could achieve the same outcome. A TSO may want to supplement capacity trading with this form of interruptible capacity if it was concerned with problems of market power, since it serves as a “use-it-or-lose-it” policy. However, in TenneT’s case, the use of an interconnector capacity cap can independently avoid market power problems. *We conclude that the second interruptible capacity method is less attractive to TenneT than the first, but suggest that TenneT explore both possibilities in further detail.* Any interruptible capacity programme would require changes to UCTE rules.

## Appendix 1: Market Description

Appendix 1 describes the Dutch electricity markets and interconnector capacity auctions.

### Dutch Electricity Markets

Electricity in the Netherlands is traded in four separate markets. Three of these are centralised, formal markets: the Day-Ahead or “spot” market and the Adjustment market run by the Amsterdam Power Exchange (“APX”), and the balancing, regulation, and reserve market operated by TenneT. The fourth comprises bilateral trades among suppliers, traders and consumers.

- The APX spot market, operational since May 1999, facilitates day-ahead electricity trading while the Adjustment market offers a means for correcting APX participants’ hourly imbalances. Only about 10% of Dutch electricity consumption is traded on the spot market,<sup>42</sup> demonstrating market participants’ preference to sign long-term bilateral contracts rather than rely on the short-term market.
- TenneT’s balancing, regulation, and reserve market ensures that electricity is balanced throughout the grid and that adequate ancillary services are provided. The total volume of settled imbalances is approximately 3% of Dutch electricity consumption.
- The bilateral market operates independently from the APX and allows buyers and sellers to negotiate transactions confidentially.

#### *APX Day-Ahead Market*

Participation in the APX Day-ahead market is voluntary for all participants except those who import power across the Belgian and German interconnectors. Any market participant can act as a buyer or seller, and all bids are entered electronically. Bids, in € per MWh, are made one-day in advance prior to market closure at 10:30 and include generators’ requests for minimum runtimes. Following market closure, the APX matches all buyers and sellers, sets the market-clearing price, and communicates final results to bidders. By 16:00 on the day prior to the day of operation, the APX publishes a final price index on its website.

The Day-ahead market functions as a two-sided, uniform price auction, comparing supply and demand on an hourly basis. Supply bids are aggregated in ascending order while demand bids are ranked in descending order. The market clearing price and volume for every hour are set by the intersection of supply and demand in that hour, given the generators’ operating restrictions. Once supply and demand are matched, the APX submits its hourly balance or energy programme (E-programme) to TenneT. As the

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<sup>42</sup> Amsterdam Power Exchange website, <http://www.apx.nl/corporate/main.html>. In May 2001, TenneT acquired all shares in the APX spot market with the aim of increasing market participation and promoting co-operation between European electricity markets.

transmission system operator (TSO), TenneT is responsible for aggregating energy schedules from multiple regions and maintaining balance throughout its system.

The Dutch Network Code requires market participants importing power across the Dutch interconnectors to sell all their imported power into the APX. -----  
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### ***APX Adjustment Market***

The APX Adjustment market is designed to correct real-time imbalances that arise from daily fluctuations in supply or demand. The market is open to all APX participants with generation in the Netherlands and operates on a continuous basis. Transactions are executed immediately whenever possible. Participants submit hourly bid and ask prices in Euro per MWh and imbalance prices are set where demand and supply meet. The Adjustment market has been in operation since February 2001.

### ***TenneT's Balancing, Regulation, and Reserve Market***

Under the Dutch Electricity Law, TenneT is responsible for balancing power in the Netherlands. Each Programme Responsible Party (PRP),<sup>43</sup> including the APX, must submit an E-programme to TenneT, detailing its net transactions and specific energy balance for each 15-minute settlement period or "PTU". Any deviations from E-programmes are priced through TenneT's balancing, regulation, and reserve market.

TenneT sets regulation and reserve power prices through two uniform price auctions, one where players bid in to supply energy (generators by increasing output, consumers by reducing load), the other where players bid in to take energy (generators by decreasing output, consumers by increasing load). Bids are aggregated in ascending order by TenneT, and final regulation and reserve power prices equal TenneT's highest accepted bid in each market. Bids are submitted one day-ahead of market operation but can be changed up to one hour before each market settles.

There are two imbalance prices, both of which are tied to the regulation market. The imbalance price for shortages is related to the positive regulation power price while the imbalance price for surpluses is linked to the negative price. Typically, the imbalance price for shortages is higher than the APX spot market price while the imbalance price for surpluses is lower than the spot market price.<sup>44</sup>

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<sup>43</sup> The title "Programme Responsible Party" derives from market participants' "programme responsibility" to maintain their own energy balance within each settlement period. -----  
----- *System Balancing in the Netherlands*, <http://www.tennet.org/html/nl/ni3/home.htm>.

<sup>44</sup> ----- *System Balancing in the Netherlands*, <http://www.tennet.org/html/nl/ni3/home.htm>.

Under the Network Code, all market participants with connection capacity greater than 60 MW must bid into the regulation and reserve markets. However, to ensure availability TenneT has contracted with the five largest generators to make available, in total, 250 MW of regulation power. This power is made available by bidding into the Regulation and Reserve Market, at the relevant APX price. The five generators are free to bid more than their contractual amount, and other market players can also choose to participate in the regulation market. In either case their bids need not be tied to the APX price.

### ***Note***

To understand imbalance and regulation prices it is necessary to note an implication of ramp-up restrictions. Because generators are limited in their ramp up rates, multiple bids may be used to meet regulation and reserve needs when only one bid would be necessary in the absence of ramp-up restrictions. For example, if 50 MW of reserve power is needed at the start of a settlement period, one generator offering 50 MW of reserve power may not be able to meet this need alone if its ramp-up rate is limited to 7% of 50 MW per minute.<sup>45</sup> As a result, TenneT must call on multiple bidders to provide the required 50 MW, causing final prices to be higher than if only the lowest bidder offering the needed capacity provided the full amount.

### ***Bilateral Market***

The bilateral market is the most important in terms of volume, representing over 80% of total power in the Netherlands. Because bilateral trades occur independently from the spot market and are confidential, there is no comprehensive publicly available data for analysing bilateral trading trends. However, trade publications such as Platts Energy Daily publish daily assessments of the Dutch market based on information provided by traders. Our analysis accounts for bilateral trades using available data.

### **Interconnector Auctions<sup>46</sup>**

The Netherlands exchanges capacity with Belgium and Germany over three main interconnectors. The Belgium interconnector is owned and controlled by Elia while Eon Netz and RWE control the two German interconnectors. All available interconnector capacity is auctioned by TenneT's Auction Office, the TSO Auction BV, through a Day, Month and Year auction. Separate auctions are held for both directions on each interconnector: Elia to TenneT, TenneT to Elia, Eon to TenneT, TenneT to Eon, RWE to TenneT and TenneT to RWE. Each PRP is limited to nominating no more than 400 MW net capacity over the three interconnectors.

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<sup>45</sup> Power offered for regulation must have a minimum ramp-up rate of 7% per minute, ensuring that it is fully available with 15 minutes notice.

<sup>46</sup> This section summarises information found on the TSO Auction BV website: <http://www.tso-auction.org>.

All interconnector bids are ranked in descending order, and final auction prices equal the lowest accepted offer. If two bidders request capacity at the same price and there is insufficient capacity to serve both, all remaining available capacity is awarded pro rata. The Day, Month, and Year auctions are described in more detail below.

### ***Day Auction***

Participants buy hourly day-ahead interconnector capacity through the electronic Day auction. Every morning by 8:30, the Auction Office publishes available capacity by interconnector on its website. Buyers then have until 9:00 to submit or adjust bids for transport the next day. At 9:00 the Day auction occurs and by 9:30, participants are informed of the results. Final prices and capacity per connection are published on the Auction Office's website. The minimum amount of auctioned capacity for the Day auction is 100 MW.

### ***Month Auction***

The manual Month auction is held every tenth working day of the month for hourly capacity the next month. Participants must submit bids by 18:00 on the working day before the auction. Bids are then opened and judged and final prices are defined for the six connections. Final capacity allocations and results are published on the website. The minimum amount of auctioned capacity for the Month auction is 100 MW while the maximum is 550 MW.

### ***Year Auction***

The Year auction is conducted at the end of the year for hourly capacity the next year. As in the Month auction, participants must send in their bidding forms manually. The maximum capacity for the Year auction is 900 MW.

### ***Resell and Transfer***

The Auction Office allows participants to return or to transfer obtained capacity, maximising interconnector allocation and use. Participants with unused Month or Year capacity can transfer all or some of their unused capacity to another registered participant or resell it to the Auction Office. Resold capacity is added to the capacity for the Month Auction if possible, otherwise it is offered on the Day Auction. The original participant recovers all revenue from capacity sold to the Auction Office.

## Appendix 2: Plant Outages

### Extent of Plant Outages

We calculated the ratio of actual available capacity to installed capacity during the highest price hour on each of the price spike days. According to our analysis, the highest ratio during the price spike days was 88% and the lowest was 84%. Table A1 shows our estimate for July 2<sup>nd</sup>, 1100 hours.

**Table A1: Ratio of Actual Capacity/Installed Capacity, July 2, 1100 hrs**

		Ratio [I]=I total/[G]total		87%					
		Temperature	[2]	22					
Unit Name [A]	Program Responsible Party [B]	Plant Type [C]	Fuel [D]	Nameplate Capacity (MW) [E]	Temperature Reduction (MW) [F]	Installed Capacity, Temperature Adjusted (MW) [G]=[E]-[F]	Outage Amount (MW) [H]	Actual Capacity, Temperature Adjusted (MW) [I]=[E]-[F]-[H]	Probability of Outage [J]
<b>Total</b>				<b>14,027</b>	<b>142</b>	<b>13,884</b>		<b>12,100</b>	

Notes and Sources:

Column [G] shows each plant's nameplate capacity adjusted for temperature while column [I] shows each plant's actual capacity also adjusted for temperature. The temperature adjustment (column [F]) affects only OCGT and CCGT plants and equals 0.7% per degree above 18 degrees Celsius. The final ratio equals the total MW available in column [I] divided by the total MW in column [G].

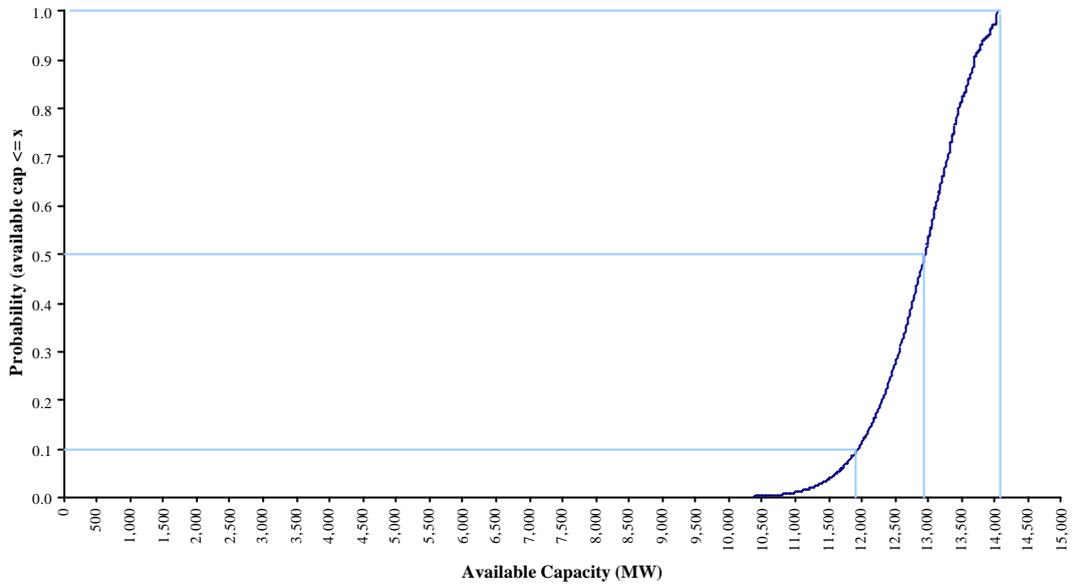
### Likelihood of Outages

We conducted a separate statistical analysis to evaluate the probability of the observed outages occurring. We utilised plant-specific forced outage rates provided by TenneT and constructed a probability ladder giving the cumulative probability of generators producing a given amount of power.

Figure A1 shows the results of our analysis.<sup>47</sup> We calculate that there is a 100% probability that there will be less than 14,100 MW of available capacity and about a 50% chance that less than 12,900 MW will be available. There is virtually no chance that there will be outages greater than 4,000 MW. Figure A1 shows that large Dutch outages, 2000 to 3000 MW, are possible but unlikely to occur during many periods of the year. We therefore conclude that availability ratios of 85% are unlikely but not at all unnatural.

<sup>47</sup> Only active plants for which we have sufficient information are included in the analysis.

Figure A1: Capacity Availability



***Extra-Confidential Material***

Once we determined the cumulative probability of outages within the Netherlands, we examined the maximum outages experienced by each generating company during the price spike period.

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Table A2: Outages During Price Spike Period

Installed Capacity (MW)	Outage (MW)	Ratio %	Likelihood that output less than ([A] - [B])	Date of outage in [B]
[A]	[B]	[C]	([A] - [B]) [D]	[E]
		[B] / [A]		

Notes and sources:

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### Appendix 3: Netherlands Market Concentration

Economists often use the Herfindahl-Hirschman Index (HHI) to measure market concentration. The HHI is a measure of the number and relative size of the firms in a market. It also has a rigorous interpretation in relation to theoretical economic models of imperfect competition. The index for any market lies in the range between zero and 10,000: close to zero for a market that is perfectly competitive with a large number of firms of similar size, and equal to 10,000 for a pure monopoly.

Our HHI calculations for the Netherlands market are based on two separate measures.<sup>48</sup> First, we estimated baseload and peak market HHIs by adding each company’s total installed capacity and import capacity to determine its total contribution to market concentration. Second, we added each company’s actual hourly output and nominated imports to calculate the relevant HHI. The first calculation indicates generators’ potential market share during the hour while the second examines their actual market share. The only difference between the baseload and peak market calculations is that the baseload market excludes all import capacity.

Tables A3, A4, A5, and A6 show our baseload and peak market HHI calculations for July 4<sup>th</sup>, 1200 hours. We show our results for July 4<sup>th</sup>, 1200 hours because that hour was the most expensive hour during the price spike period. We apply the same approach as shown in the Tables below throughout the entire price spike period. As shown in the main body of our report, the HHI values do not vary much during the price spike days.

**Table A3: Baseload HHI (Variable Cost<27 €/MWh), Actual Output, July 4 1200 hrs (APX Price Spike=1201 €/MWh)**

Company [A]	Former Name [B]	Plant Output (MW) [C]	Market Share (%) [D] [C]/[C] <sub>total</sub>	HHI Contribution [E] [D] <sup>2</sup>
<b>Total</b>		<b>6,844</b>		<b>2,165</b>

<sup>48</sup> As in section 4, plants – – – – – have been included in the dataset used for the following analysis.

**Table A4: Baseload HHI (Variable Cost<27 €/MWh), Actual Capacity, July 4 1200 hrs (APX Price Spike=1201€/MWh)**

Company [A]	Former Name [B]	Total Capacity (MW) [C]	Market Share (%) [D] [C]/[C] <sub>total</sub>	HHI Contribution [E] [D] <sup>2</sup>
<b>Total</b>		<b>8,509</b>		<b>2,044</b>

**Table A5: Peak HHI (Variable Cost>27 €/MWh), Actual Output, July 4 1200 hrs (APX Price Spike=1201€/MWh)**

Company [A]	Former Name [B]	Total Output from Peaking Plants (MW) [C]	Total Nominated Imports (MW) [D]	Total Capacity (MW) [E] [C]+[D]	Market Share (%) [F] [E]/[E] <sub>total</sub>	HHI Contribution [G] [F] <sup>2</sup>
<b>Total</b>				<b>5,462</b>		<b>1,572</b>

Interconnector Capacity

**Total** **5,462** **1,572**

Notes and Sources:

**Table A6: Peak HHI (Variable Cost>27 €/MWh), Actual Capacity, July 4 1200 hrs (APX Price Spike=1201€/MWh)**

Company [A]	Former Name [B]	Total Peaking Plant Capacity (MW) [C]	Total Import Capacity (MW) [D]	Total Capacity (MW) [E] [C]+[D]	Market Share (%) [F] [E]/[E] <sub>total</sub>	HHI Contribution [G] [F] <sup>2</sup>
<b>Total</b>				<b>9,808</b>		<b>2,106</b>

Interconnector Capacity

**Total** **9,808** **2,106**

Notes and Sources:

## Appendix 4: Gasunie's Imbalance Charges

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**Table A7: Imbalance Penalty**

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**Conversion Factors**

Annual Tariff Inflation Index	[1]
Discount Factor for Transportation Charge	[2]

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**Inputs**

Number of Days Imbalanced in 2001	[3]
Day of APX Price Spike	[4]
Gasunie Weighting Period	[5]
Total Imbalance (m <sup>3</sup> /MWh)	[6]
Distance from Groningen (km)	[7]

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**Transportation Charge**

Entry Fee (€m <sup>3</sup> )	[8]
Distance Related Fee (€m <sup>3</sup> /100km)	[9]
Connection Fee (€m <sup>3</sup> )	[10]
Dr	[11]
Gasunie Entry Weighting	[12]
Gasunie Transportation Weighting	[13]
Transportation Tariff (€m <sup>3</sup> )	[14]
Indexed Transportation Tariff (€m <sup>3</sup> )	[15]
Discounted Transportation Tariff (€m <sup>3</sup> )	[16]
Transportation Charge (€MWh)	[17]

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**Capacity Charge**

Capacity Tariff (€m <sup>3</sup> )	[18]
Indexed Capacity Tariff (€m <sup>3</sup> )	[19]
Capacity Charge (€MWh)	[20]

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Incidental Capacity Charge (€MWh) [21]

***Total Imbalance Penalty (€/MWh)*** [22]

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Notes:

