# RESEARCH INTO GAS FLEXIBILITY SERVICES:

# RESPONSE TO GASTERRA/CRA COMMENTS

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## Disclaimer

**The NMa has informed *The Brattle Group* that it is satisfied that this report does not contain any confidential information. *The Brattle Group* cannot accept responsibility for any loss or damage resulting from the release of information contained in this report.**

# 1 Introduction and Summary

The Dutch Gas Act stipulates that, if GasTerra has a dominant position in the market for flexibility services, the national operator of the gas transmission network (Gastransport Services or GTS), must offer flexibility services to shippers.[1] GasTerra is also obliged to make GTS an offer for the requested flexibility services based on 'reasonable' tariffs and conditions.

The Dutch Gas Act specifies that the *NMa Energiekamer* (NMa) is responsible for determining whether GasTerra has a dominant position in the market for flexibility services at regular intervals. Specifically, the focus is on short-term flexibility products that would be offered to manage differences in supply and demand over the following week, as opposed to seasonal flexibility which manages differences between demand in the summer and the winter.

In December 2010 the NMa retained *The Brattle Group* to analyse GasTerra's position in the flexibility market for the period 2012-2016 inclusive. We produced an initial report for public consultation dated June 6th 2011 (the June 2011 report), in which we found that GasTerra was dominant in the market for short-term flexibility for the period 2012-2016 inclusive. Following the publication of the June 2011 consultation report, GasTerra and other parties submitted a number of comments. Subsequently, we produced a final report dated August 2nd 2011, hereafter referred to as the August 2011 report, which took into account the comments received from GasTerra and others.[2] The August 2011 report also concluded that GasTerra was dominant in the market for short-term flexibility market for the period 2012-2016 inclusive.

Following the publication of the August 2011 report, GasTerra and a consultant retained by GasTerra (Charles River Associates or CRA) submitted further comments at an event hosted by the NMa on August 31st 2011.[3] At the request of GasTerra CRA also prepared a report which criticised the August 2011 report – hereafter referred to as 'the CRA report'.[4] The NMa has asked *The Brattle Group* to address the comments raised by GasTerra/CRA in detail, and in particular to investigate the effect that adopting the alternative assumptions suggested by GasTerra/CRA would have on our findings.

### Addressing CRA's criticisms

CRA criticised our measurement of demand because it mixed weekly peak demand with average seasonal (winter-summer) demand. To address this criticism, we have re-calculated demand as maximum weekly demand less average gas demand in the same week.

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[1] A new balancing system came into effect in the Netherlands in April 2011, which involves a balancing market or bid ladder. GTS will continue to offer a flexibility product in 2011 – the main difference being that shippers will nominate hourly values for the use of the flexibility service the day ahead. Shippers can re-nominate their use of the flexibility service within the gas day.

[2] The Brattle Group (Dan Harris, José Antonio García and Ilinca Popescu), Research into Gas Flexibility Services Method decision flexibility services 2011, August 2nd 2011. Available at www.nma.nl.

[3] CRA, Brattle's methodology for assessing dominance in the market for gas flexibility. An economic commentary. August 31 2011. Presented by Diana Jackson, Vice President.

[4] Diana Jackson, CRA, 'Brattle's methodology for assessing dominance in the market for gas flexibility - An economic commentary' 22 September 2011. Hereafter referred to as the CRA report.

CRA raised a similar criticism regarding our supply curves, noting that we were mixing seasonal supply (winter and summer supply curves) with a weekly demand, and that this was inconsistent. In our August 2011 report we were explicit that the decision not to develop weekly supply curves was a trade-off between accuracy and the amount of work involved. Nevertheless, in response to CRA's comments we have developed weekly supply curves.

Using weekly supply and demand curves we find that for over 80% of the time GasTerra has a market share of at least 40% in all years, and a share of over 80% about 60% of the time in 2016. We conclude that the use of weekly supply and demand curves do not change our finding of dominance.

CRA disagreed with our exclusion of exported flexibility from the market. Among other things, CRA noted that instead of excluding exported flexibility from the market we should simply give it an appropriate price. Accordingly, we have researched the price of foreign (non-Dutch) storages. This is the logical basis for pricing re-imported capacity, since parties re-importing their flexibility to the Netherlands would have to buy replacement flexibility, most likely from gas storages. We find that including all exported flexibility at the average cost of foreign storage does not affect the August 2011 results. This is because re-imported flexibility is too expensive to be in the relevant markets for most levels of demand and so adding the re-imported flexibility at the price of foreign storage does not change the results.

CRA claim that our August 2011 has failed to properly take into account the interconnectedness of the Dutch gas and flexibility market. In essence, CRA claimed that even if the Dutch flexibility market was perfectly competitive, then it could be that the cost of flexibility in the Netherlands would roughly equal the price of flexibility in foreign markets. CRA's argument is incorrect on both a theoretical and empirical level. On the theoretical level, CRA fail to take account for the presence of transport constraints into and out of the Dutch market. While Dutch producers might want to export their flexibility to foreign buyers, the presence of transport constraints limits their ability to do so. When there are transport constraints, prices diverge. On an empirical level, our methodology fully accounts for the presence of flexibility imports and exports, and we find that exports are not sufficient to result in price convergence over the relevant period. We see that the price of flexibility as measured by GasTerra's virtual storage auctions is about 40% lower than the price of foreign flexibility. We conclude that we have properly accounted for the interconnectedness of the Dutch flexibility market.

In our August 2011 report, we made the point that products are only considered substitutes if they are sold at a similar price. Specifically, for each week we defined the relevant product market in that particular week to include all flexibility services with costs less than or equal to a "benchmark competitive price". CRA claim that our sub-market analysis is 'novel'. But there is nothing novel about differentiating product markets according to cost. CRA claim that our approach differs from the FERC's Delivered Price Test (DPT), which was the model for our approach. But where there are differences this is simply because of differences in available information or the specifics of the Dutch flexibility market as opposed to the US electricity market. The FERC's DPT test – in common with the market definition methodology used in our August 2011 report – excludes producers that are 'out of the market' where their production is too expensive.

CRA also note that we had not defined the market according to the 'Small but Significant and Non-transitory Increase in the Price' or SSNIP test. While we maintain that the market definition approach we applied in our August 2011 report was appropriate, to address CRA's comments we have re-run our analysis by using a SSNIP test to define the relevant market for each week. We find that using the SSNIP test to define the markets still results in GasTerra having a market share of more than 50% about 75% of the time.

In our August 2011 report we concluded that the best approach was to base the supply curve for flexibility on the total costs of flexibility, rather than only the variable costs. CRA claimed that our use of total costs was incorrect, and that we should base our analysis on variable costs, since, among other things the fixed costs are 'sunk' and therefore play no part in, for example, decisions on whether or not to withhold capacity from the market. We maintain our view that the use of total costs is correct, because this fits with the prices that we actually see in the market. Setting storage prices based on the intersection of a variable cost curve and demand would result in flexibility prices far below those we see in reality. CRA do not address this issue in their comments. For example, the price of GasTerra's virtual storage product consists of a fixed fee, set by auction, and a variable cost. Similarly, charges for the bundled storage product that NAM used to sell, and which the virtual storage product has replaced, also consisted of a fixed fee and a variable fee.

Nevertheless, to address CRA's concern, we have re-run the sub-market analysis using only variable costs. We find that while GasTerra is significantly less dominant than using total costs, it still has a market share of between 40-50% for more than 40% of the time. The results are perhaps unsurprising, when we consider that the variable costs of all flexibility sources are very similar, so we get a very flat supply curve. With a flat supply curve, the results will tend to look like the simple market share analysis presented in our August 2011 report, where the products are not differentiated by cost. We maintain that looking at variable costs only is not the correct way to define the relevant markets. However, even if one did adopt this approach, GasTerra would still have a dominant market share for about half the time.

In our August 2011 report we took the case that imported flexibility was most likely to be provided by foreign gas storages. For simplicity, we set the price of foreign storage to be the same as the average Dutch storage price, but we accounted for the additional cost of buying entry capacity at the border that foreign storages had to bear. CRA questioned this assumption, and asked why we did not link the cost of imports to flexible Norwegian or UK gas production. In our August 2011 report we already explained that flexibility from producing fields was generally expensive. If it was not, there would be no point building gas storage facilities. Using the cost of flexibility from offshore fields far from the market would result in a higher cost, and reduce further the competitive constraint on GasTerra. Nevertheless, as we discuss above we have refined our analysis to include an average of foreign gas storage costs as the price of imported flexibility. We find that using the average foreign storage price for the price of imported flexibility does not affect our August 2011 results. This is because the foreign storage is still too expensive to be a part of the relevant market for most levels of demand, and so does not affect the sub-market shares.

In our August 2011 report we added a 'premium' for summer flexibility, noting that the loss of some days of injection and withdrawing gas in the summer could result in there being less gas available in the winter. CRA claims that our different treatment of storage in the summer months is invalid, or at least inconsistent with the treatment of storage in winter. We maintain that seasonal gas storages sometimes need to be injecting constantly over the summer and shoulder period

months so as to fill the reservoir for the following winter, so that the provision of upward flexibility in summer could interfere with the planned injection program and have a cost for the following winter. However, to address CRA's concern we have re-run the analysis without the 20% summer premium on gas storage. We find that eliminating the 20% summer premium does not affect our August 2011 results. This is because in the summer demand for flexibility is relatively low, so that storage is not a relevant part of the supply curve.

We combine the changes discussed above to see how they affect the results and conclusions of the August 2011 report. The changes we apply in combination are:

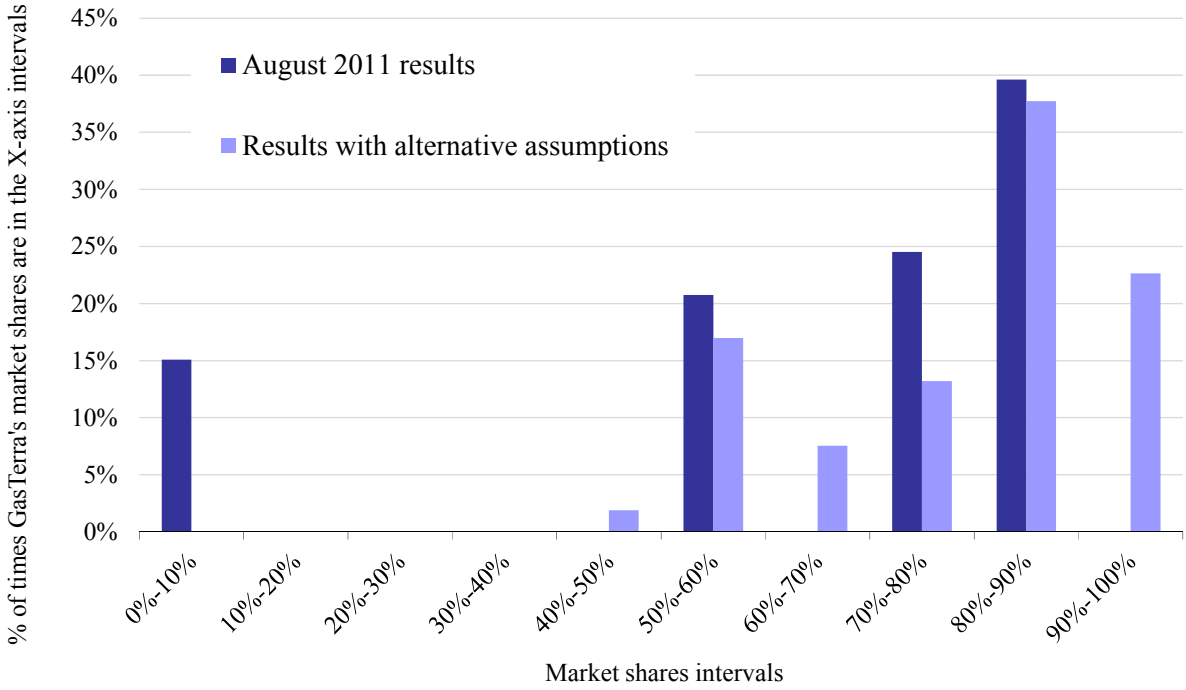
1) Using a weekly demand based on maximum demand in a week less average demand in a week;
2) Defining a separate supply curve for each week;
3) Including all exported flexibility in the market at the price of foreign storage;
4) Defining the relevant market for each week using the SSNIP test;
5) Changing the costs of imports to be based on the actual cost of foreign storages (rather than the average Dutch storage price);
6) Eliminating the summer storage premium.

Figure 1 illustrates that the combination of the changes above actually increase GasTerra's average market share, relative to our August 2011 report, in 2016. Whereas in our August 2011 report GasTerra sometimes had a market share of less than 40%, with the changes above GasTerra always has a market share of over 40% in 2016. GasTerra has a market share of at least 40% about 95% of the time in all years.

We have also re-run the pivotal supplier and withholding analysis using the combination of changes above. We find that GasTerra is pivotal around 82% of the time for the period 2012-2016, compared to 84% in the August 2011 report. We find that GasTerra would have the incentive and ability to raise prices by more than 10% above the competitive level in 2012 for 74% of the time (the equivalent figure in the August 2011 report was 94%). GasTerra has the incentive and ability to raise prices by more than 10% nearly 75% of the time in 2016 (the equivalent figure in the August 2011 report was 83%).

We conclude that CRA's suggested changes to our August 2011 methodology do not change, and in some cases actually re-enforce, our finding that GasTerra is dominant in the market for short-term flexibility for the period 2012 to 2016.

**Figure 1: Sub-market analysis for 2016 with and without the alternative assumptions**

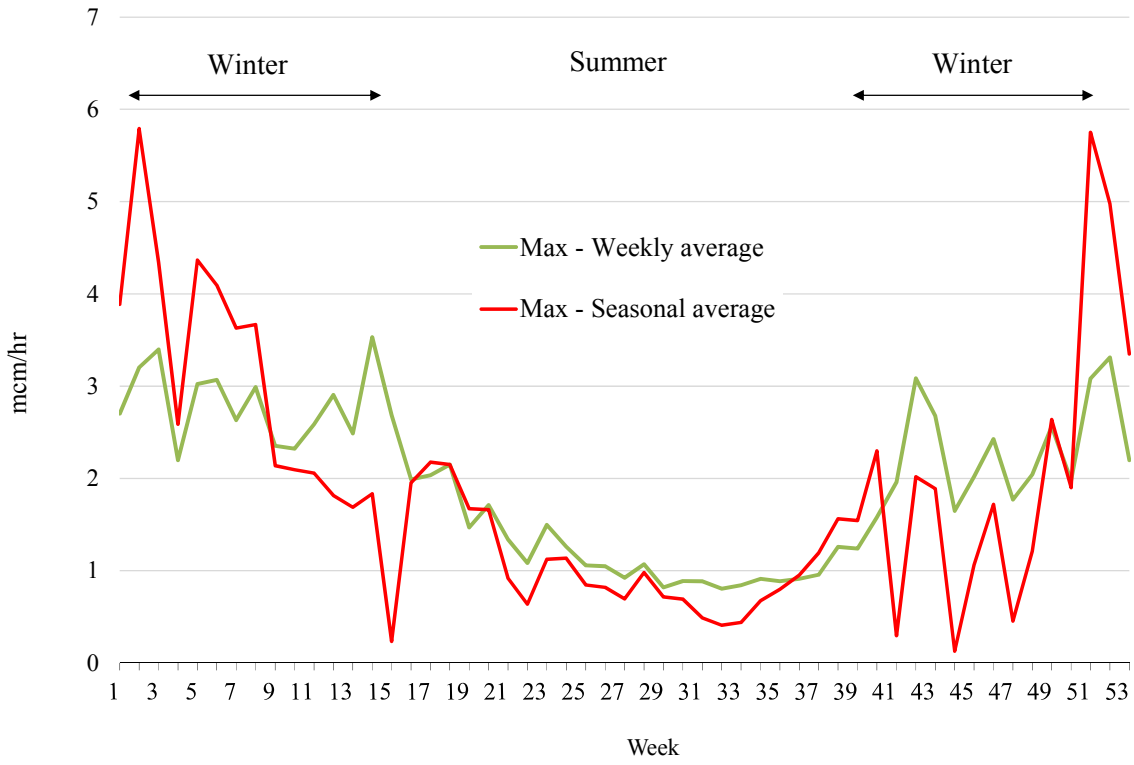



## 2 Measurements of flexibility

In our August 2011 report, we defined weekly flexibility as being the maximum demand in a week less the average demand over a season, the latter being either winter or summer. CRA criticised our measurement of demand because it mixed different periods. If the maximum demand in a week was below the average seasonal demand, this could result in negative demand.

To address this criticism, we have re-calculated demand as maximum weekly demand less average gas demand in the same week. Figure 2 illustrates weekly demand for flexibility using our original measure and the revised measure of demand using the measure suggested by CRA. The revised measure of demand is flatter, so that in winter demand does not increase as much as using our previous demand measure. This is because the difference between the peak demand in a week and average demand in a week in the middle of winter is smaller than the difference between peak demand in a week in the middle of winter and demand over the whole winter. In contrast, since gas demand is relatively flat in summer, the revised and original demand measures are very close over the summer.

**Figure 2: Revised vs. original weekly demand measure**




CRA raised a similar criticism regarding our supply curves, noting that we were mixing seasonal supply (winter and summer supply curves) with a weekly demand, and that this was inconsistent.

In our August 2011 report, we said that "[w]e acknowledge that supply will also vary within a season, so that our approach will tend to overestimate the supply of flexibility in the height of winter, and underestimate supply in the shoulder periods. But on average it will give an accurate representation of how the potential to exercise market power varies over the year, while keeping the analysis tractable."[5]

In other words, we were explicit that the decision not to develop weekly supply curves was a trade-off between accuracy and the amount of work involved. Nevertheless, in response to CRA's comments we have developed weekly supply curves. This involves two main changes with respect to our earlier analysis.

First, we have accounted for the variation in Groningen production over the summer and winter. Groningen produces more than the average winter level of gas in the peak of the winter. This means that the use of weekly supply curves will reduce the estimated supply of Groningen flexibility available at the peak of the winter, but increase it at the shoulder periods.

Second, we account for the decrease in gas storage withdrawal capacity over the course of the winter, and the increase in withdrawal capacity as storages are re-filled over the summer. Gas

[5] August 2011 report, p.19.

storages usually specify their maximum withdrawal rate assuming a full gas reservoir. But as gas is withdrawn from storage, the pressure in the reservoir drops, reducing maximum withdrawal rates to below their 'nameplate' maximum amount.

We have used the relationship between withdrawal capacity and gas in storage from GasTerra virtual storage product. Since the characteristics of the storage product should be based on the actual physical characteristics of the physical storages under GasTerra's control in the Netherlands, then this seems most appropriate.[6] We have also confirmed by looking at the contracts for foreign storages that the withdrawal factors in the GasTerra virtual storage contract are typical for physical storages.

Note that we do not account for the reduction of the capacity of foreign storage over the course of the winter. This is because in the case of foreign storage the limiting factor is the import capacity at the border, not the physical withdrawal capacity of all foreign storage.

Figure 3 illustrates the weekly supply of capacity for each week for 2012, and contrasts this with the approach taken in our August 2011 report where we used summer and winter supply curves. Figure 3 shows that our August 2011 approach overestimated the supply of flexibility in the summer. The reason for this is that we now take account for the fact that storages would or could be empty at the beginning of the summer, and so less flexibility is available. In the winter, as we expected, the use of seasonal supply curves underestimates the amount of flexibility available at the beginning of the winter and overestimates the amount available in the middle of the winter.

[6] Specifically, GasTerra specify a 'withdrawal factor'. Multiplying the nameplate withdrawal capacity by the withdrawal factor gives the actual withdrawal capacity at any time. According to the virtual storage product contract, in case the actual amount of gas in storage per Standard Bundled Unit (SBU) at the end of hour H-1 is between 0 kWh and 864 kWh, the withdrawal factor increases linear from 0.6 to 1.0 In case the actual amount of gas in storage at the end of hour H-1 is between 864 kWh and 1440 kWh, the withdrawal factor equals 1.0 See Appendix A, GasTerra Storage Services Agreement.

**Figure 3: Weekly versus seasonal supply curves in 2012**

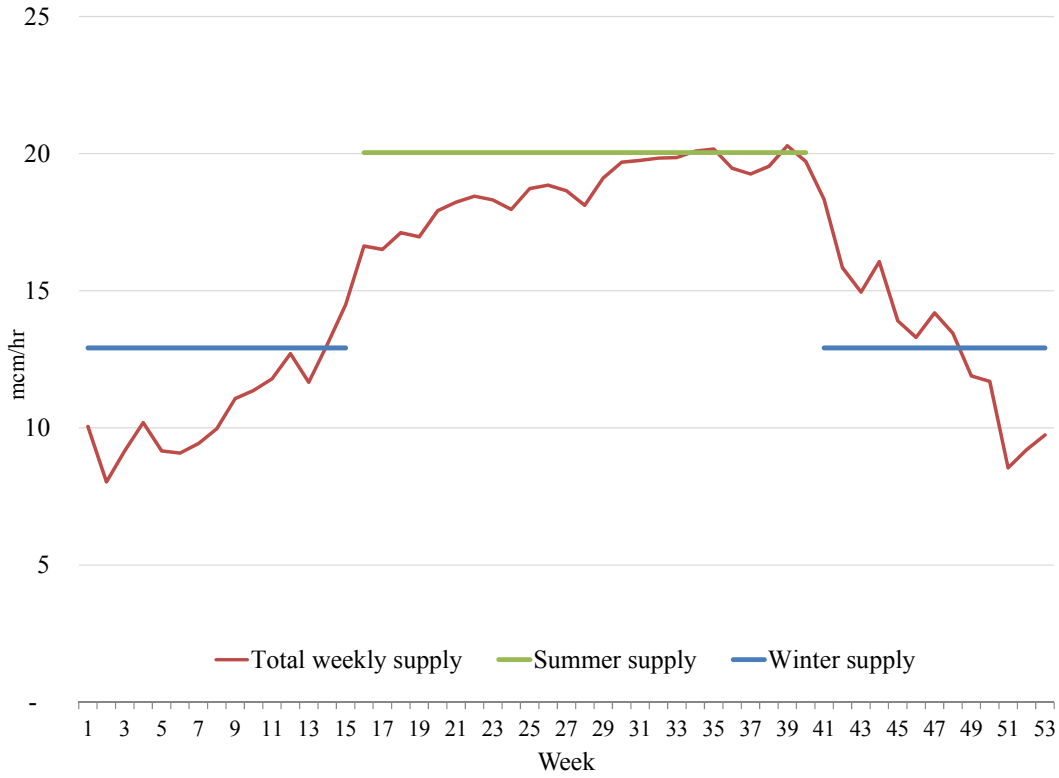
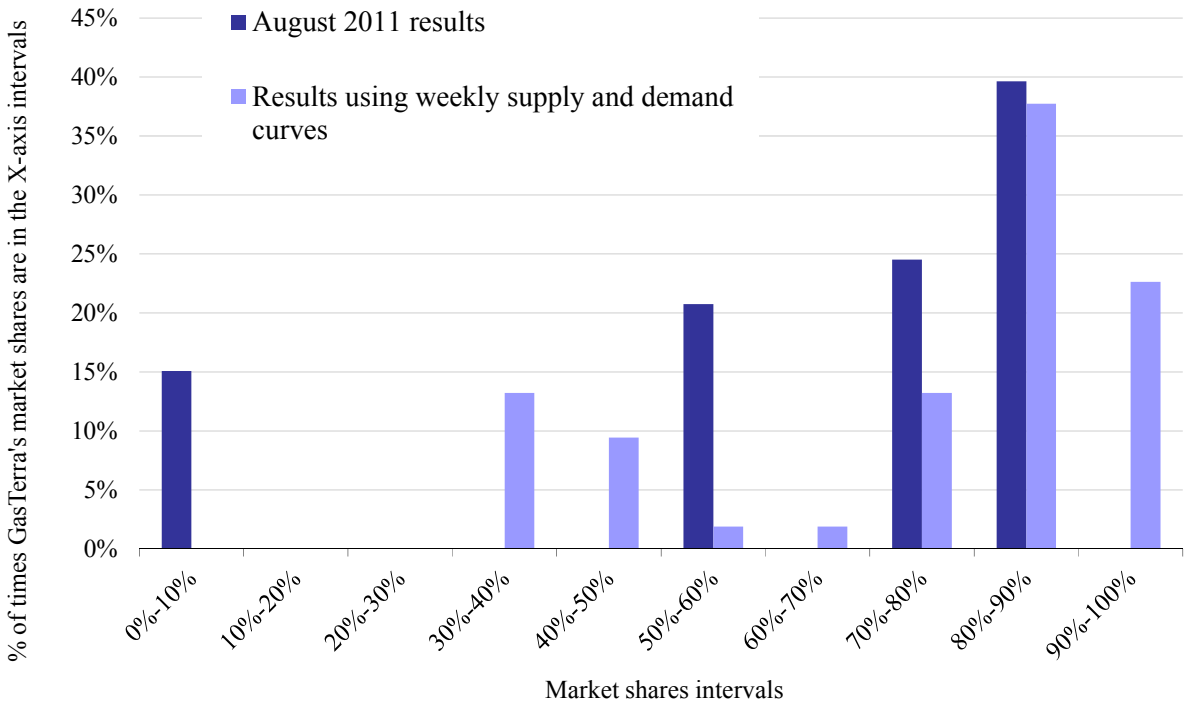



Figure 4 contrasts the distribution of the GasTerra's market shares for 2016 in our August 2011 report and by applying the weekly supply curves. We chose 2016 because it is impractical to display the results for all five years for the old and new case on a single graph, and 2016 is the year in which GasTerra has the lowest share of capacity according to the simple market share analysis – so if GasTerra is dominant in 2016 it is likely to be dominant in earlier years as well. We display full results for all the years in the appendix, and confirm that 2016 is indeed a good representative year.

Figure 4 shows that, with the weekly supply curves and demand curves, GasTerra never has a market share of less than 30%. Also, the more graduated supply curve gives a more even distribution over the market share intervals relative to our August 2011 approach. However, for over 80% of the time GasTerra has a market share of at least 40% in all years, and a share of over 80% about 60% of the time in 2016. We conclude that the use of weekly supply and demand curves do not change our finding of dominance.

**Figure 4: Sub-market analysis for 2016 using weekly supply curves and the August 2011 methodology**




## 3 Treatment of exports

In our August 2011 report, we recognised that flexibility sold by GasTerra under long-term export contracts was not under the control of GasTerra, and should not count toward GasTerra's share of the market. At the same time, we also recognised reasons why it would be impractical for buyers of exported flexibility to re-import significant amounts of flexibility into the Dutch market at a price that could compete effectively with GasTerra's other flexibility products. Specifically, we noted that the buyers of GasTerra's exported flexibility would have to re-import the flexibility using a non-firm backhaul service, and second they would need to buy flexibility to replace the GasTerra service that they are now using in the Netherlands. While we included some re-importing of flexibility, based on historic back-haul flow data, we considered that on balance it would not be reasonable for the NMa to suppose that re-imported flexibility could exercise a competitive restraint on GasTerra's pricing.[7]

In their comments CRA did not find our reasons for excluding the re-import of exports from the Dutch market convincing. CRA noted that the non-firm nature of backhaul was not an obvious problem. We agree that market participants can use backhaul up to their forward flow limit, and it will in effect be firm. While the flow is technically not firm – because back-haul is never firm – we agree that this is not the main problem for re-importing exports.

[7] August 2011 report, section 3.2 pp.9-10.

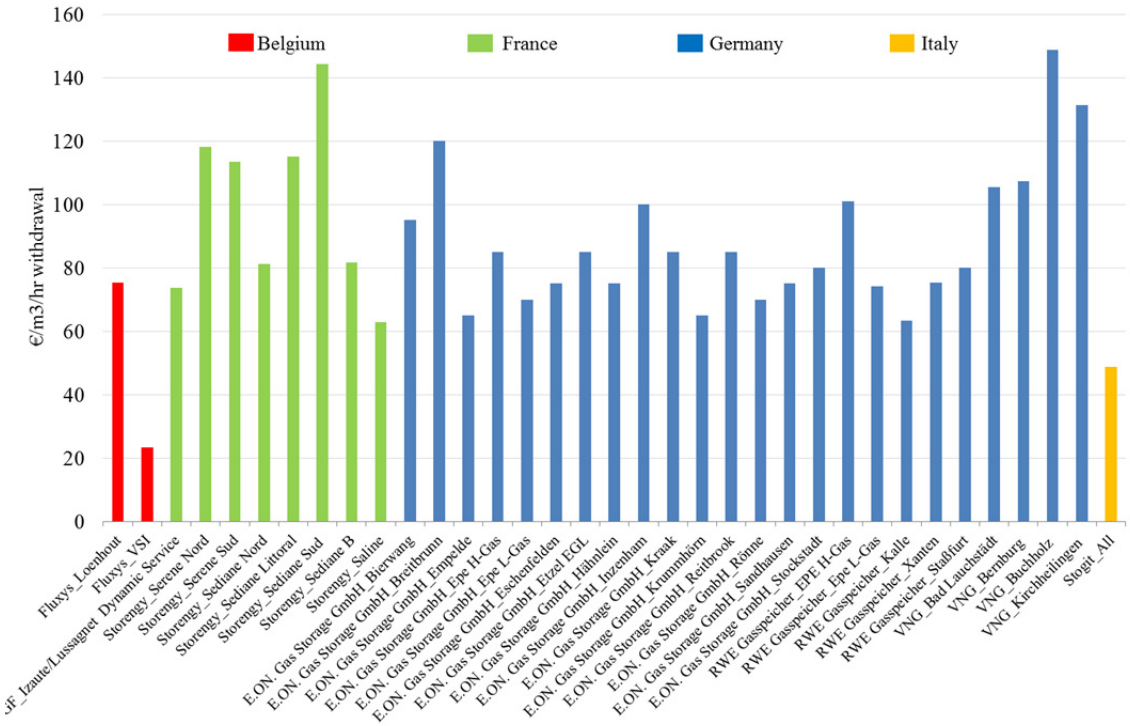
CRA also claimed that, while the party that had re-imported flexibility into the Netherlands would need to replace this flexibility, the same would apply to imports. This is not correct. With imports as we model them, a flexibility provider outside of the Netherlands has made a deal to sell flexibility to customers in the Netherlands. The importer has not made any deal to sell the same flexibility to other customers outside of the Netherlands, and so there is no need to replace the flexibility. In contrast, a party buying flexibility from GasTerra under a long-term export contract has committed the flexibility to customers in its home market. If the buyer now decides instead to sell the GasTerra flexibility to Dutch customers, it must continue to fulfil its obligations to customers in its home market by providing a replacement source of flexibility – for example gas storage sourced from another provider outside of the Netherlands. It is the difficultly and expense of sourcing the replacement flexibility that we highlighted in our August 2011 report.

CRA also claimed that the gas is already at the border, so that transport costs for re-importing the gas is limited. This comment misunderstands how an entry-exit gas transport tariff system works. As soon as the gas is outside of the Dutch entry-exit system, the party re-importing the gas must buy entry capacity at the border. It does not matter whether the gas is delivered 1 metre downstream of the border or 100 km. the cost of re-importing gas is the same.

CRA commented that the cost of finding alternative sources of flexibility could be accounted for by cost measures – so in other words that we could estimate the cost of finding an alternative source of flexibility outside of the Netherlands. The main reason why we did not do this in the August 2011 report is that it is not clear from where the parties re-importing gas would buy replacement flexibility and at what price.

Nevertheless, to address this issue, we have researched the price of gas storage – being the most likely source of replacement flexibility – in countries outside of the Netherlands. We looked at the price of storage for a sample of facilities in France, Belgium, Italy and Germany. These countries represent the main export markets for GasTerra, and so are the most likely places where parties re-importing flexibility to the Netherlands would obtain replacement flexibility services. Figure 5 illustrates the range of storage withdrawal prices. The Appendix contains the actual data used to make Figure 5.

**Figure 5: Price of withdrawal capacity in Belgium, France, Germany and Italy**




Since there are a different number of data points for each country we first take an average price for each country, and then take the average of this average Otherwise the single Italian data point – which represents a several storages that all have the same price, would not be given enough weight. We find that the average price of withdrawal capacity is 71 €/m$^3$/hour. This is about 20% higher than the average price of withdrawal capacity in the Netherlands – based on our bottom up approach – of about 58 €/m$^3$/hour, and is significantly more than the price of flexibility based on the virtual storage auction prices which was 44 €/m$^3$/hour.

Our estimate of the cost of obtaining replacement flexibility is likely to be an underestimate of the true cost for two reasons. First, the estimates in Figure 5 exclude the cost of entry and exit capacity to and from the storage facility from the network. Adding these costs would increase the cost of foreign flexibility. Second, Italy and Belgium have relatively low flexibility costs, but in both countries access to storage is rationed and generally restricted to parties serving domestic customers. In reality it would be difficult or impossible to buy replacement flexibility services at short-notice in either country. Prices for flexibility in Italy and Belgium are low not because of a surplus of supply, but because the prices are regulated. If we ignored the Italian and Belgian storage prices, the average price of flexibility in France and Germany is 94 €/m$^3$/hour significantly higher than the 71 €/m$^3$/hour we use in our revised calculations. In the August 2011 report, we assumed that the cost of re-imported flexibility was 78 €/m$^3$/hour.

We maintain that excluding the re-import of flexibility services is the correct way to estimate GasTerra's position in the flexibility market, since for the reason given above it seems unlikely that the NMa could rely on the re-import of flexibility to constrain market power. Nevertheless, to address GasTerra's concerns with this approach we have also re-run the sub-market analysis, assuming that all exported flexibility can be re-imported into the Netherlands.

We find that including all exported flexibility at the average cost of foreign storage does not affect the August 2011 results. This is because re-imported flexibility is too expensive to be in the relevant markets for most levels of demand – an issue we discuss below in detail – and so adding the re-imported flexibility at the new price does not change the results.

# 4 The Competitive Price of Dutch Flexibility

CRA claim that our August 2011 has failed to properly take into account the interconnectedness of the Dutch gas and flexibility market. In essence, CRA say that even if the Dutch flexibility market was perfectly competitive, then it could be that the cost of flexibility in the Netherlands would roughly equal the price of flexibility in foreign markets. Dutch flexibility producers would prefer to sell their flexibility at the higher foreign price, and the price of Dutch and foreign flexibility would converge.[8] CRA claim that "the Brattle report appears to calculate the competitive price of flexibility ….through a comparison of domestic supply against domestic demand: both net of exports."[9]

However, CRA's argument is incorrect on both a theoretical and empirical level. On the theoretical level, CRA fail to take account for the presence of transport constraints into and out of the Dutch market. By defining the relevant market as the Netherlands – something that CRA does not challenge – we must account for the presence of transport constraints. While Dutch producers might want to export their flexibility to foreign buyers, the presence of transport constraints limits their ability to do so. When there are transport constraints, prices diverge. For example, in gas commodity markets one often sees price differences between markets where there are transport constraints. Gas prices today are roughly 7-10 €/MWh in the US, 22-25 €/MWh in the GB market and 35-40 €/MWh in Asian gas markets. These differences exist because there is a limited ability to transport gas between these markets.

On an empirical level, our methodology fully accounts for the presence of flexibility imports and exports, and we find that prices will not converge over the relevant period. CRA's statement that we only look at domestic (Dutch) flexibility supply is clearly incorrect, since we account for the presence of imports. Regarding exports, we withdraw exported flexibility from the supply curve, which shifts the supply curve to the left and increases the price of flexibility. But we see that there is not a sufficient volume of exports to make the price of flexibility in the Netherlands reach the same level as the price of foreign flexibility. For whatever reasons, suppliers of flexibility in the Netherlands do not export sufficient flexibility to equilibrate prices. This conclusion is supported by the findings of the market today. As discussed in the previous section, we see that the price of flexibility as measured by GasTerra's virtual storage auctions is about 40% lower than the price of foreign flexibility. We conclude that we have properly accounted for the interconnectedness of the Dutch flexibility market.

[8] CRA report section 4.3 pp.15-16.

[9] CRA report ¶ 61 p.15.

# 5 Market definition

In our August 2011 report, we made the point that products are only considered substitutes if they are sold at a similar price. An expensive product is usually not a substitute for a cheaper product. We described the 'Small but Significant and Non-transitory Increase in the Price' or SSNIP test, and noted that two products – which perform similar functions – priced within 5-10% of each other are usually regarded as reasonable substitutes. To differentiate between products with different costs, we adopted a version of the methodology of the US Federal Energy Regulatory Commission's (FERC) Delivered Price Test (DPT). The DPT is well established in the United States. The FERC routinely conducts the DPT test to analyse market power for those firms applying for Market Based Rates Authorities (MBRs) *i.e.* rates for selling power that are not approved by a regulator,[10] and merger proceedings in electricity markets for many years. The DPT has been affirmed by the courts.[11]

Specifically, in our August 2011 report for each week we defined the relevant product market in that particular week to include all flexibility services with costs less than or equal to a "benchmark competitive price". The latter was defined, for each week, as 1.10 times the market price, which was itself defined by the intersection of flexibility supply and demand.[12]

CRA claims our approach to market definition is inconsistent with the FERC DPT, because the latter is based on actual market prices, whereas we use an estimated competitive price.[13] Specifically, according to the FERC:[14,15]

> The Delivered Price Test defines the relevant market by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's economic capacity and available economic capacity for each season/load condition. The results of the Delivered Price Test can be used for pivotal supplier, market share and market concentration analyses. [footnote omitted; emphasis added]

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[10] *Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy*, 107 F.E.R.C. § 61,018 (2004) [hereinafter 2004 MBR Order].

[11] See, for instance, Wabash Valley Power Associates, Inc. v. FERC, 268 F. 3d 1105 (D.C. Cir. 2001).

[12] This approach means that, if the marginal flexibility supplier sets the market clearing price based on an offer of €50, all units with costs less than, or equal to, €55 have a competitive effect on the offer of the marginal flexibility supplier.

[13] CRA report section 4.2.2 pp.13-15.

[14] 2004 MBR Order, ¶ 106.

[15] A staff summary of the mechanics of the DPT Test is provided in Appendix F in the 2004 MBR Order. For a complete description of the Delivered Price Test and its requirements, see Appendix A of the *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, 61 FR 68595 (Dec. 30, 1996), III FERC Stats. & Regs. ¶ 31,044 (Dec. 18, 1996), *reconsideration denied*, Order No. 592-A, 62 FR 33341 (1997), 79 FERC ¶ 61,321 (1997) [Merger Policy Statement]; see also *Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, 65 Fed. Reg. 70,983 (2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,111 (2000), *order on reh'g*, Order No. 642-A, 66 Fed. Reg. 16,121 (2001), 94 FERC ¶ 61,289 (2001).

However, CRA fail to acknowledge that in the case of the flexibility market, we do not have market prices available for each time period. Instead we must estimate market prices, based on our estimate of demand and the intersection of demand with the supply curve. Our approach differs from the FERC DPT only because less information is available to us. CRA offer no solution to the absence of market prices at different levels of demand.

CRA also fail to acknowledge that another fundamental difference between the FERC's DPT and the application in this case is that we are investigating possible dominance. In contrast, the FERC is determining if price regulation can be relaxed. CRA itself notes that:

> "Defining markets where the question is whether or not a dominant position exists is not straightforward, for reasons that are well known. Specifically, it may be difficult to distinguish in the empirical data between a situation in which a competitive firm is competing with a wide range of alternatives, and a situation where a dominant firm has raised its price until it is competing with a wide range of alternatives." "One approach to this problem is to estimate what a competitive market price would be based on available evidence on costs and demand, and then test whether the firm in question would have the ability and incentive to raise prices above that level."[16]

This is precisely the approach we have taken. We conclude that our use of estimated competitive prices is correct, because we are investigating a case of potential dominance. The FERC DPT uses actual market prices, but this is both because market prices are available and because the FERC is not investigating dominance. Therefore our approach differs from the FERC DPT for both theoretical and practical reasons.

CRA claim that the use of a 10% over the market price is "entirely ad hoc", and is also inconsistent with the FERC DPT. It is true that the FERC defines the market as all suppliers that have a cost not more than 5% higher than the average market price for a given time period.[17]. But ort use of a 10% cut-off (instead of a 5% cut-off) should tend to underestimate GasTerra's market shares in this case. Because GasTerra tends to control a greater proportion of cheaper Groningen flexibility, the use of a 10% cut-off will tend to include more non-GasTerra capacity in the relevant market.

The use of a 10% cut-off instead of a 5% cut-off as used by FERC is not 'ad hoc' and does not make our approach inconsistent with the DPT test. The U.S. Department of Justice/Federal Trade Commission Merger Guidelines suggest a 5% price threshold but acknowledge that others may be appropriate.[18] The European Commission itself suggests a range of "5% to 10%" increase in price to apply the SSNIP test.[19] Moreover, applying a lower 5% threshold would exclude more products from the relevant market.

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[16] CRA report ¶¶ 25-26 p.7.

[17] FERC's DPT test includes all "suppliers that could sell into the destination market at a price less than or equal to 5% over the market price. That is, determine which generators have costs less than or equal to 1.05 times the market price". 2004 MBR Order, ¶ 106, Appendix F, p. 93.

[18] U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, issued April 2, 1992, 57 FR 41,552 (1992), at 41555.

[19] See Market Definition Guidelines, ¶ 17.

We conclude that the use of a 10% cut-off is consistent with the ranges used in EU and US merger guidelines. The use of a 10% cut-off will tend to include more non-GasTerra products in the relevant market, which will tend to underestimate GasTerra's market share.

CRA claim that because we use total costs, we again exclude too many products relative to a case where variable costs were used. It is not clear that this is correct. Which products are excluded from the relevant market depends on the estimated price and the cost of potentially competing products. On the one hand, if we had used variable costs then the estimated competitive price would also have fallen. On the other hand, the costs of all products would be lowered, since variable costs are clearly lower than total costs. Therefore it is not clear that using variable costs would have resulted in more or less products being excluded from the market. Comparing prices based on total costs with the total costs of suppliers is consistent. We discuss the issue of variable vs. total costs in the following section in some detail.

In its comments, CRA noted that it is incorrect to exclude products that are more than 1.1 times the market price, according to the 'Small but Significant and Non-transitory Increase in the Price' or SSNIP test, and that the SSNIP test refers to a 5-10% change in the price level, rather than 5-10% differences in price levels.[20]

The CRA comment regarding the SSNIP test is correct, but also misrepresents what was said in our August 2011 report. We did not claim to be applying the SSNIP test. Rather, we simply referred to the SSNIP test as support for the idea that one should define product markets according to the differences in the price or cost of different products. The market definition that we applied – which is also used by the FERC – provides a sense of which flexibility suppliers own (or control) the largest shares of cheap flexibility products that enjoy competitive advantage over more expensive flexibility products in the market. The relevant market includes all supply that is potentially competitive with GasTerra and excludes supply that is not potentially competitive with GasTerra.

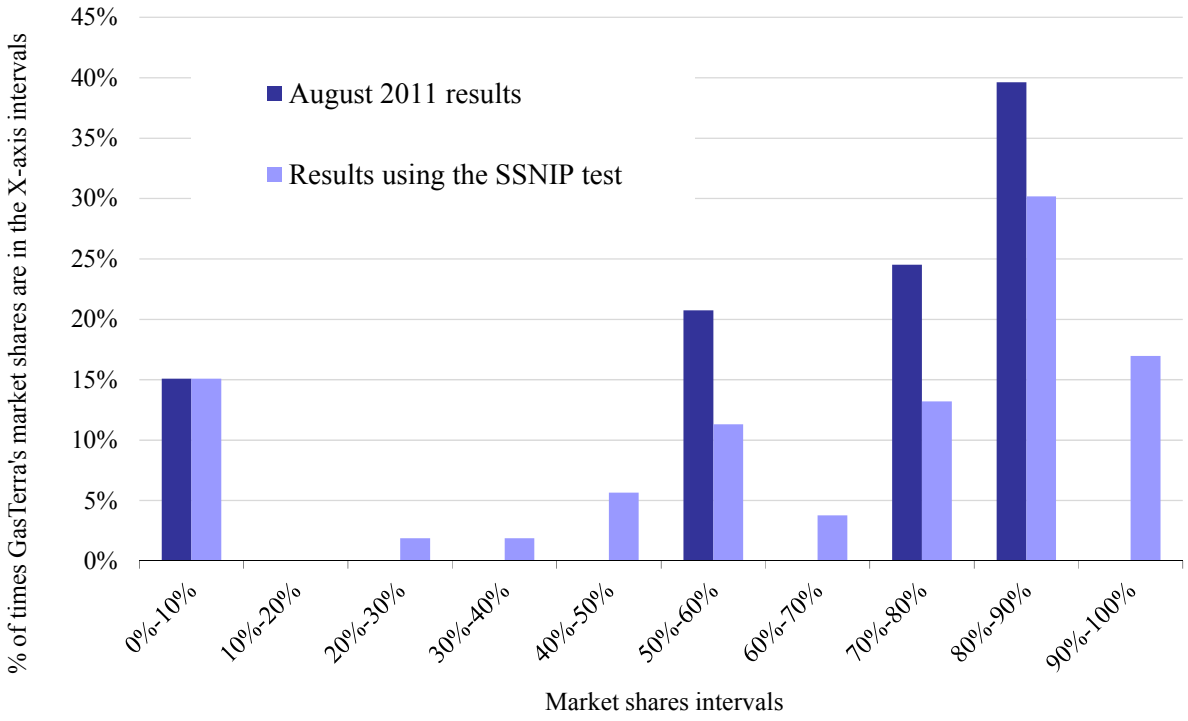
The intuition behind this approach is that sources of supply which are much more expensive that the marginal source of supply do not apply a significant competitive constraint on the dominant supplier. Even large quantities of expensive capacity from alternative suppliers would not restrict the dominant player from raising prices above the benchmark competitive price. The basic principle behind this approach is thus also consistent with the logic behind the SSNIP test defined by the European Commission in its guidelines on market definition. The FERC DPT approach is a good approximation for the SSNIP test, and is simpler to apply because there is no need to calculate profits and changes in profits for a hypothetical price rise.

While we maintain that the market definition approach we applied was appropriate, to address CRA's comments we have re-run our analysis by using a SSNIP test to define the relevant market for each week. For each week, we measure the profit of a hypothetical monopolist having total control over the cheapest flexibility product. We then test if the hypothetical monopolist can profitably raise prices by more than 10%. If it cannot, we give the hypothetical monopolist control over the next most expensive product, and repeat the test. The subset of products for which it is profitable for the hypothetical monopolist to raise the price by more than 10% defines the relevant product market.

[20] CRA report ¶ 54 p.13.

Figure 6 illustrates the results of the sub-market analysis defining the product market using the SSNIP test for 2016 and the results of our August 2011 approach for 2016. Using the SSNIP test to define the markets still results in GasTerra having a market share of more than 50% about 75% of the time.

**Figure 6: Sub-market analysis for 2016, August 2011 results vs. results with the market defined using the SSNIP test**




CRA complains that we have not applied the SSNIP test, but then refers to the EDF/British Energy case notes that "in which the Commission defined a single electricity generation market in the UK, despite the fact that nuclear and renewable generation variable costs are a fraction of those for coal and/or gas fired generation."21 CRA imply that all cost differences between products should be ignored. CRA also calls our approach of differentiating markets by the cost of different products "novel".[22]

It is not novel to distinguish different product markets according to the costs of the various products. Rather, it is standard practise. The FERC's DPT test recognises not only peak and off-peak electricity markets but actually uses 10 different time horizons, implying 10 different submarkets by time. The Spanish competition authority (the CNC), in its decision on the Gas Natural/Union Fenosa merger, excluded older, more expensive gas plants from its analysis of the power market because these plants did not run often and could not constrain the market power of

[21] CRA report ¶ 54 pp.13-14.

[22] CRA report ¶ 34 p.9.

other cheaper plants.[23] The UK's Office of Fair Trading merger guidelines note that "[c]ustomer markets may also be defined on the basis of temporal markets, for example where customers are not able to substitute products between time periods (e.g. due to the seasonality of product supply or the different prices for peak and off-peak services)."[24] Trade journals and power exchanges also recognise distinct peak and baseload electricity products.

Whether the Commission or any other competition authority defines distinct product markets within the electricity market depends on the issues at hand. If two generators have a similar mix of peak and baseload plant then it may not be required to define these product markets. On the other hand if two baseload power producers were to merge, a competition authority would have a legitimate concern that the merged producers could push up the price of off-peak power to the level of peak power. Even a competitive peak electricity market would do nothing to stop this. Defining a single electricity market in such a case would lead to an overestimate of the level of competition in the market, since peak power producers could not prevent the merged off-peak power producers from raising prices. The SSNIP test would recognise such a distinction, and define distinct peak and off-peak markets.

In previous work for the NMa *The Brattle Group* applied a SSNIP test in defining the relevant geographic markets for mergers of electricity generators in the Netherlands.[25] We applied the test for both peak and off-peak product markets. Subsequently the NMa stated that "[o]n the production and wholesale market for electricity, a distinction was made between the production and wholesale market for electricity during peak hours and the production and wholesale market for electricity during off-peak hours."[26] In its decision on the RWE/Essent merger, the European Commission acknowledged the NMa's distinction between peak and off-peak but concluded that there was no need to analyse the market using these distinctions for that particular case.[27] That the European Commission did not apply the peak and off-peak market definitions does not mean that they reject the concept that markets should be defined by differences in production costs.

# 6 Measuring costs

In our August 2011 report we discussed the approach to measuring costs at some length, acknowledging that this is a difficult issue. In sum we concluded that the best approach was to base the supply curve for flexibility on the total costs of flexibility, rather than only the variable costs. There did not seem to be any obvious opportunity costs to providing short-term flexibility, expect

[23] CNC Decision Expte- C.0098/08 Gas Natural/Union Fenosa ¶¶ 488 – 497.

[24] Merger Assessment Guidelines, A joint publication of the Competition Commission and the Office of Fair Trading September 2010 CC2 (Revised) OFT1254 ¶5.2.31 p.38

[25] 'Factors Affecting Geographic Market Definition and Merger Control for the Dutch Electricity Sector,' by Boaz Moselle, David Newbery, and Dan Harris, The Brattle Group Limited, June 2006.

[26] Vision Document: Mergers on the Energy Markets, NMa November 2006 ¶25.

[27] "[w]ithin the market for generation and wholesale supply, the Dutch Competition Authority (the 'NMa') distinguishes between "peak hours" and "off-peak hours". In addition, they also consider the possibility of a further distinction between peak and "super-peak hours". However the response to the current market investigation in this regard was inconclusive. The definition of the relevant product market can therefore be left open, as this does not change the final assessment." Case No COMP/M.5467 - RWE / ESSENT Article 6(1)B Decision In Conjunction With Article 6(2) Non-Opposition Date: 23/06/2009 ¶25.

for seasonal gas storage. Even in that case we argued that the best approach as still to use either the market price of storage or the estimated total costs of storage.

CRA raised several objections to our approach:

- Our arguments for rejecting opportunity costs are incorrect;
- Our arguments for using total costs are not correct;
- Fixed, or investment costs, should not play a role in a withholding analysis, since the costs are 'sunk' and therefore do not affect short-term profitability. Investment costs do not influence short-term usage decisions;
- Assuming that the cost of import flexibility is based on gas storage costs may not be correct;
- It may not be correct to assume that storage withdrawal costs are higher in winter than in summer;

## 6.1 Variable vs. Total costs

CRA notes that prices based on variable costs are often used when modelling electricity markets. Electricity markets are usually organised with the marginal plant setting prices for all other plants. Generators recover their fixed or capital costs from the difference between their variable costs and the higher variable costs of the price-setting plant. But even this view of the market is too simplistic. In electricity markets without capacity payments, always offering at variable costs would not allow many generators, especially peaking generators to recover the costs of their investments. Assuming some departure from variable cost pricing is required to allow cost recovery. We also see that in electricity markets prices often exceed the variable costs of the price setting plant. CRA note that FERC's DPT uses variable or marginal costs. But most US generators receive separate capacity payments, which make a significant contribution to their capital costs. US generators can afford to offer at marginal costs because of the presence of capacity payments.

In the specific case of short-term flexibility products, there is no organised market with a single price. Instead, deals are struck bilaterally, or there are occasional auctions for GasTerra's flexibility products. The prices of the deals that we can see are not based only on variable costs. For example, the price of GasTerra's virtual storage product consists of a fixed fee, set by auction, and a variable cost.[28] Similarly, charges for the bundled storage product that NAM used to sell, and which the virtual storage product has replaced, also consisted of a fixed fee and a variable fee.[29] In power markets where bilateral deals are struck, the price is not based on the variable costs of the power plant – rather it based on a fixed fee and a variable cost fee. CRA note that the UK Competition Commission used marginal costs to analyse the Centrica/Rough acquisition. But this does not seem to fit the circumstances of the Dutch flexibility market. Setting storage prices based on the intersection of a variable cost curve and demand would result in flexibility prices far below those we see in reality.

[28] See GasTerra Storage Services Agreement, section 3.1, available from www.apxendex.com

[29] See for example 'Standard Short Gas Storage Services Agreement Between Nederlandse Aardolie Maatschappij B.V. And Customer For The Period 1 April 2011 – 31 March 2012' section 3.

CRA itself quotes the DG Competition Guidelines: "[a]ny economic model which explicitly or implicitly supports a theoretical claim must rely on assumptions that are consistent with the facts of the industry under consideration."[30] We have considered the facts of the industry under consideration, and conclude that the use of total costs is the most appropriate measure. In response to our original explanation of this point in our August 2011 report CRA also note that "it would not be surprising that the value at which this optionality [to use flexibility] is sold across a full year reflected a higher cost than the pure operating cost associated with the service."[31] CRA also note that the market price "by definition must be the same as or higher than the competitive price".[32] So CRA acknowledge that annual flexibility products would be sold at above variable costs. But CRA offers no guidance as to what kind of mark-up over variable costs they would expect or consider reasonable.

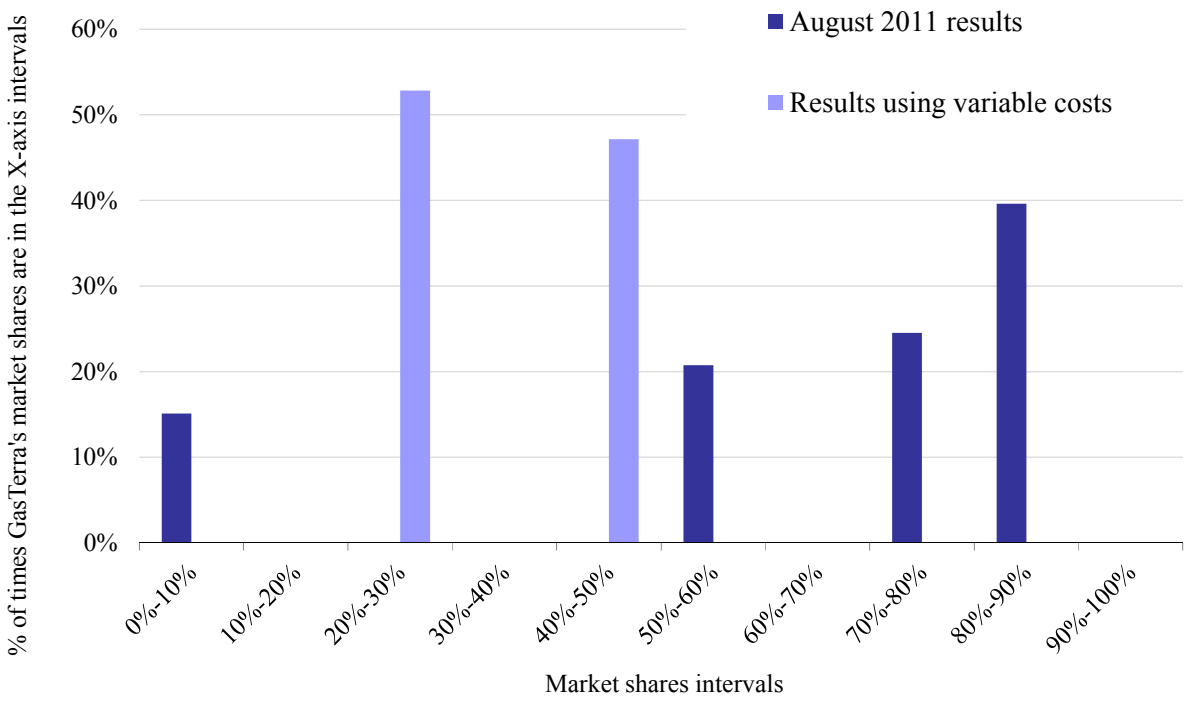
Nevertheless, to address CRA's concern, we have re-run the sub-market analysis using only variable costs. Figure 7 illustrates the results of the sub-market analysis compared to the original analysis which used total costs for 2016. Figure 7 shows that, basing the analysis on variable costs only, GasTerra is significantly less dominant than using total costs – though GasTerra still has a market share of between 40-50% for more than 40% of the time. The results are perhaps unsurprising, when we consider that the variable costs of all flexibility sources are very similar, so we get a very flat supply curve. With a flat supply curve, the results will tend to look like the simple market share analysis, where the products are not differentiated by cost. We maintain that looking at variable costs only is not the correct way to define the relevant markets. However, even if one did adopt this approach, GasTerra would still have a dominant market share for about half the time.

[30] CRA report, footnote 7 p.8.

[31] CRA report ¶82.a p.19.

[32] CRA report ¶55.a p.14.

**Figure 7: Sub-market analysis using variable, rather than total costs to define prices and markets**




CRA also note that, in terms of the withholding analysis, from the suppliers point of view the fixed costs are sunk, and the relevant measure for profitability are the variable costs, and that the "the opportunity cost of the opposite action (i.e. failing to use flexibility in order to withhold it from the market) is commensurately higher (as there are few physical costs that can be avoided through withholding)."[33] This is essentially the same point – that the variable costs are low, and so withdrawing capacity sacrifices a relatively large profit according to CRA.

However, if the fixed costs were truly sunk, then it would not be consistent for the suppliers to offer based on total costs. They would offer based only on variable costs, which is the point CRA make. But as we point out above this does not seem to be consistent with how the market works in practise, and it does not represent an equilibrium because the suppliers would not be able to recover their fixed costs.

## 6.2 The opportunity cost concept

CRA comment that our arguments for rejecting the opportunity cost approach is wrong, and note that an opportunity cost approach could use either market based or modelled prices.[34]

To be clear, we are not rejecting the concept of opportunity costs in its entirety. One interpretation of our approach of using total costs is that by building, for example, a gas storage facility, the developer incurs an opportunity cost it could have spent the money on something else.

[33] CRA report ¶76 p.18.

[34] CRA report section 4.4.1 pp.16-18.

The developer will only build the storage if the return is as good as another investment of equivalent risk. But this kind of reasoning, while theoretically correct, is not particularly enlightening in this case. In our August 2011 report we stated that we rejected the idea of an opportunity cost based on the idea that by producing gas for the short-term flexibility a facility was giving up another valuable opportunity. For example, if the Groningen field provides some upward flexibility, this does not limit the field's ability to produce gas later in the year. Rather, there is a cost for the field in building and maintaining the capacity for providing flexibility, and it is this cost that we consider in our analysis.

Ultimately CRA offers few concrete alternative measurements of cost or prices based price on opportunity costs. CRA agree that the opportunity cost is probably low from existing sources. They then note that if the flexibility provider is not sacrificing much to produce flexibility then it would be prepared to offer it at prices below total cost. But this amounts to a repeat of the total vs. variable cost discussion above. CRA posit that perhaps the relevant opportunity cost is the price of foreign storage. This amounts to a repeat of the argument that the price of Dutch flexibility should be equal to the price of foreign flexibility – an issue we dealt with in section 4 and found to be incorrect.

### 6.3 Import costs

In our August 2011 report we took the case that imported flexibility was most likely to be provided by foreign gas storages. For simplicity, we set the price of foreign storage to be the same as the average Dutch storage price, but we accounted for the additional cost of buying entry capacity at the border that foreign storages had to bear. This resulted in a cost of about 56 €/$m^3$/hour.

CRA questioned this assumption, and asked why we did not link the cost of imports to flexible Norwegian or UK gas production. CRA note that "Brattle's approach effectively assumes that imports are a close constraint on Dutch storage facilities but not on Dutch offshore production: but they provide no logical support for that view."[35]

This is not correct. In appendix I.2 of our report we explained that flexibility from producing fields was generally expensive. If it was not, there would be no point building gas storage facilities. It is expensive to provide flexibility by increasing and decreasing production from a field that is far removed from the market. This is because the pipelines that carry the gas would need to be built to carry the maximum gas flow, even if this maximum was rarely used. Instead long-distance pipelines tend to be used close to their maximum capacity at all times, and differences between supply and demand are managed by injecting or withdrawing gas into storages that are close to the market. This is why it seems most appropriate to assume that gas storages will define the costs of imported flexibility. Using the cost of flexibility from offshore fields far from the market would result in a higher cost, and reduce further the competitive constraint on GasTerra.

CRA note that they "would expect this cost [of imported flexibility] will vary across the year depending on the price at which flexible gas is available outside the Netherlands (which may well come not only from storage, but also from other off-shore gas fields brought onshore in the UK,

[35] CRA report section 4.4.4 p.21.

Norway or elsewhere)."[36] But the prices for flexibility in these contracts, if it is defined at all, are confidential. CRA do not suggest where such data is available.

Nevertheless, as we discuss above we have refined our analysis to include an average of gas storage costs in Italy, Belgium, Germany and France. We have re-run the analysis with imported flexibility priced at the average of foreign storage costs, plus the additional border entry capacity required. This results in a higher cost for imported flexibility of about 84 €/$m^3$/hour. The price of imported flexibility goes up because foreign storage is actually considerably more expensive than Dutch storage. We find that using the actual average foreign storage price for the price of imported flexibility does not affect our August 2011 results. This is because the foreign storage is still too expensive to be a part of the relevant market for most levels of demand, and so does not affect the sub-market shares.

### 6.4 Summer and winter storage costs

In our August 2011 report, we noted that if seasonal gas storages provided upward flexibility in the summer, then they would have to switch from injection to supply mode. We noted that this could entail risks, in particular that the storage would not be able to fill up before the start of the winter withdrawal season. The loss of some days of injection and withdrawing gas in the summer could result in there being less gas available in the winter. We discussed this in section 4.2 of the August 2011 report. To account for this additional risk and costs of withdrawing gas from storage, we added a premium of 20% to the cost of storage in the summer.

CRA claims that our different treatment of storage in the summer months is invalid, or at least inconsistent with the treatment of storage in winter. According to CRA the storage facility might have to restrain production so as to 'keep some flexibility in reserve' to meet short-term flexibility demand, so that winter flexibility also has a cost, because the storage might not be able to withdraw all of its gas over the winter.[37] CRA also noted that the facility does not have to switch from injection to withdrawal mode to provide upward flexibility – it could simply reduce the rate of injection. CRA noted that the premium on summer storage further weakened the ability of gas storage and imports to compete with cheaper forms of flexibility during the summer.

We maintain that seasonal gas storages sometimes need to be injecting constantly over the summer and shoulder period months so as to fill the reservoir for the following winter, so that the provision of upward flexibility in summer could interfere with the planned injection program and have a cost for the following winter.

However, to address this concern in a simple and complete way we have re-run the analysis without the 20% summer premium on gas storage. We find that eliminating the 20% summer premium does not affect our August 2011 results. This is because in the summer demand for flexibility is relatively low, so that storage is not a relevant part of the supply curve.

[36] CRA report ¶91 p.21.

[37] CRA report ¶87.a p.20.

# 7 Combination of effects

In the section above we illustrated the effect of each change individually. We now combine the changes to see how they affect the results and conclusions of the August 2011 report. The changes are:

1. Use a weekly demand based on maximum demand in a week less average demand in a week;
2. Define a separate supply curve for each week;
3. Include all exported flexibility in the market at the price of foreign storage;
4. Define a market for each week using the SSNIP test;
5. Change the costs of imports to be based on the actual cost of foreign storages (rather than the average Dutch storage price);
6. Eliminate the summer storage premium.

Figure 8 illustrates that the combination of the changes above actually increase GasTerra's average market share relative to our August 2011 report, in 2016. Whereas in our August 2011 report GasTerra sometimes had a market share of less than 40%, with the changes above GasTerra always has a market share of over 40% in 2016. Figure 9 shows that GasTerra has a market share of at least 40% about 95% of the time in all years.

We have also re-run the pivotal supplier and withholding analysis using the combination of changes above. We find that GasTerra is pivotal around 82% of the time for the period 2012-2016, compared to 84% in the August 2011 report. We find that GasTerra would have the incentive and ability to raise prices by more than 10% above the competitive level in 2012 for 74% of the time (the equivalent figure in the August 2011 report was 94%). GasTerra has the incentive and ability to raise prices by more than 10% nearly 75% of the time in 2016 (the equivalent figure in the August 2011 report was 83%).

We conclude that CRA's suggested changes to our August 2011 methodology do not change, and in some cases actually re-enforce, our finding that GasTerra is dominant in the market for short-term flexibility.

**Figure 8: Sub-market analysis for 2016 with and without the alternative assumptions**

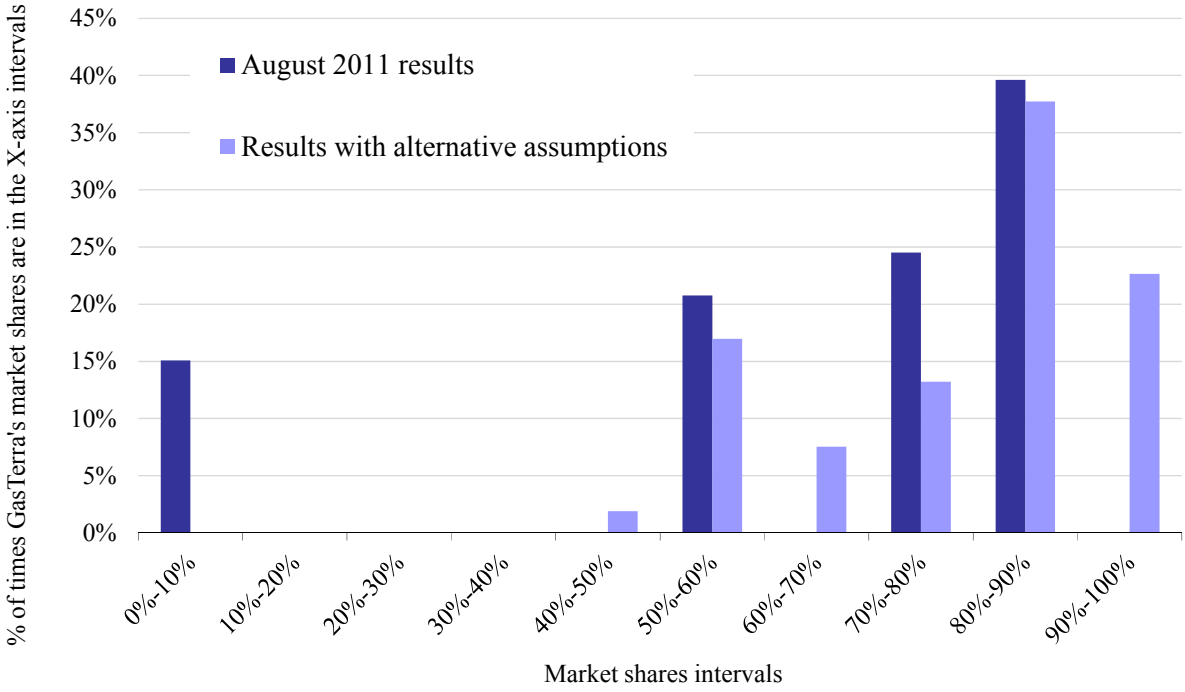
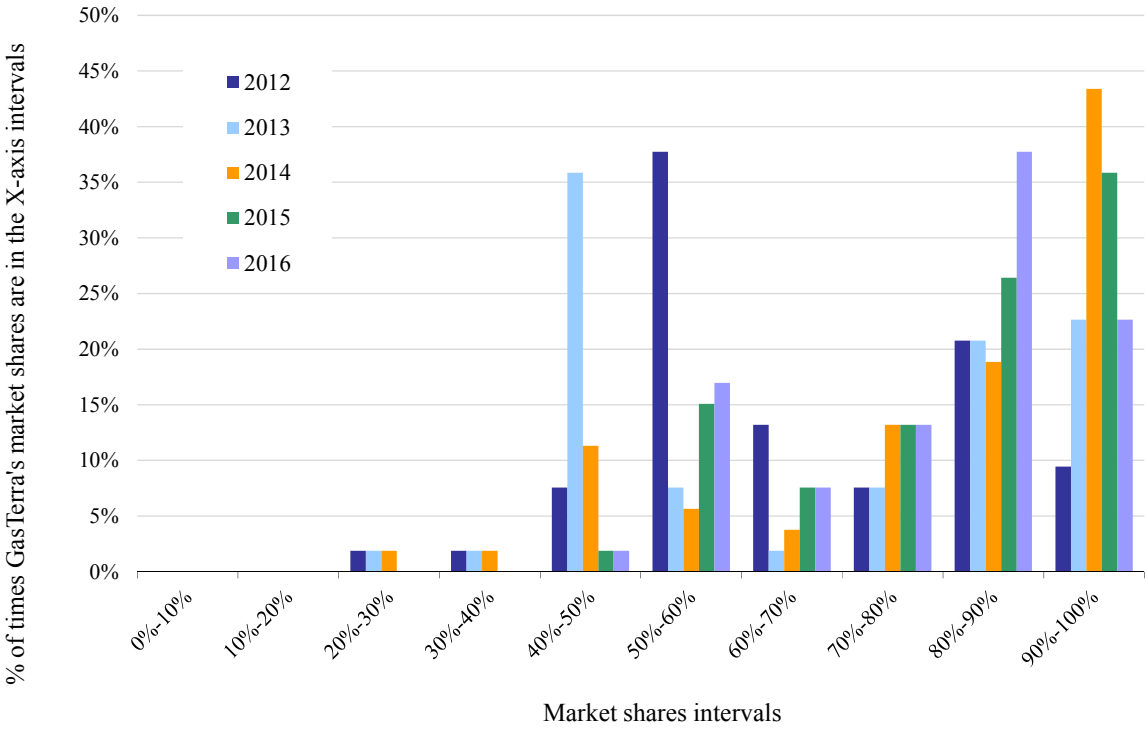



**Figure 9: Sub-market shares analysis with all alternative assumptions, all years**



# Appendix I : Details of calculations

**Table 1: Details of costs of flexibility per storage facility**

| Country | Storage | Price, €/m3/hr withdrawal | Country average |
|---|---|---|---|
| Belgium | Fluxys_Loenhout | 75.3 | |
| | Fluxys_VSI | 23.4 | 49.4 |
| France | TIGF_Izaute/Lussagnet Dynamic Service | 73.9 | |
| | Storengy_Serene Nord | 118.3 | |
| | Storengy_Serene Sud | 113.5 | |
| | Storengy_Sediane Nord | 81.2 | |
| | Storengy_Sediane Littoral | 115.2 | |
| | Storengy_Sediane Sud | 144.4 | |
| | Storengy_Sediane B | 81.8 | |
| | Storengy_Saline | 63.1 | 98.9 |
| Germany | E.ON. Gas Storage GmbH_Bierwang | 95.1 | |
| | E.ON. Gas Storage GmbH_Breitbrunn | 120.2 | |
| | E.ON. Gas Storage GmbH_Empelde | 65.1 | |
| | E.ON. Gas Storage GmbH_Epe H-Gas | 85.1 | |
| | E.ON. Gas Storage GmbH_Epe L-Gas | 70.1 | |
| | E.ON. Gas Storage GmbH_Eschenfelden | 75.1 | |
| | E.ON. Gas Storage GmbH_Etzel EGL | 85.1 | |
| | E.ON. Gas Storage GmbH_Hähnlein | 75.1 | |
| | E.ON. Gas Storage GmbH_Inzenham | 100.2 | |
| | E.ON. Gas Storage GmbH_Kraak | 85.1 | |
| | E.ON. Gas Storage GmbH_Krummhörn | 65.1 | |
| | E.ON. Gas Storage GmbH_Reitbrook | 85.1 | |
| | E.ON. Gas Storage GmbH_Rönne | 70.1 | |
| | E.ON. Gas Storage GmbH_Sandhausen | 75.1 | |
| | E.ON. Gas Storage GmbH_Stockstadt | 80.1 | |
| | RWE Gasspeicher_EPE H-Gas | 101.1 | |
| | RWE Gasspeicher_Epe L-Gas | 74.3 | |
| | RWE Gasspeicher_Kalle | 63.6 | |
| | RWE Gasspeicher_Xanten | 75.4 | |
| | RWE Gasspeicher_Staßfurt | 80.2 | |
| | VNG_Bad Lauchstädt | 105.5 | |
| | VNG_Bernburg | 107.3 | |
| | VNG_Buchholz | 148.9 | |
| | VNG_Kirchheilingen | 131.4 | 88.3 |
| Italy | Stogit_All | 48.8 | 48.8 |
| **Averages** | | | |
| | Excluding VSI, Belgium | | 77.8 |
| | Including Fluxys VSI, Belgium | | 71.4 |
| | Excluding VSI, Belgium and Italy storage | | 87.5 |

**Figure 10: Sub-market shares analysis, using seasonal supply curves (August 2011 results)**

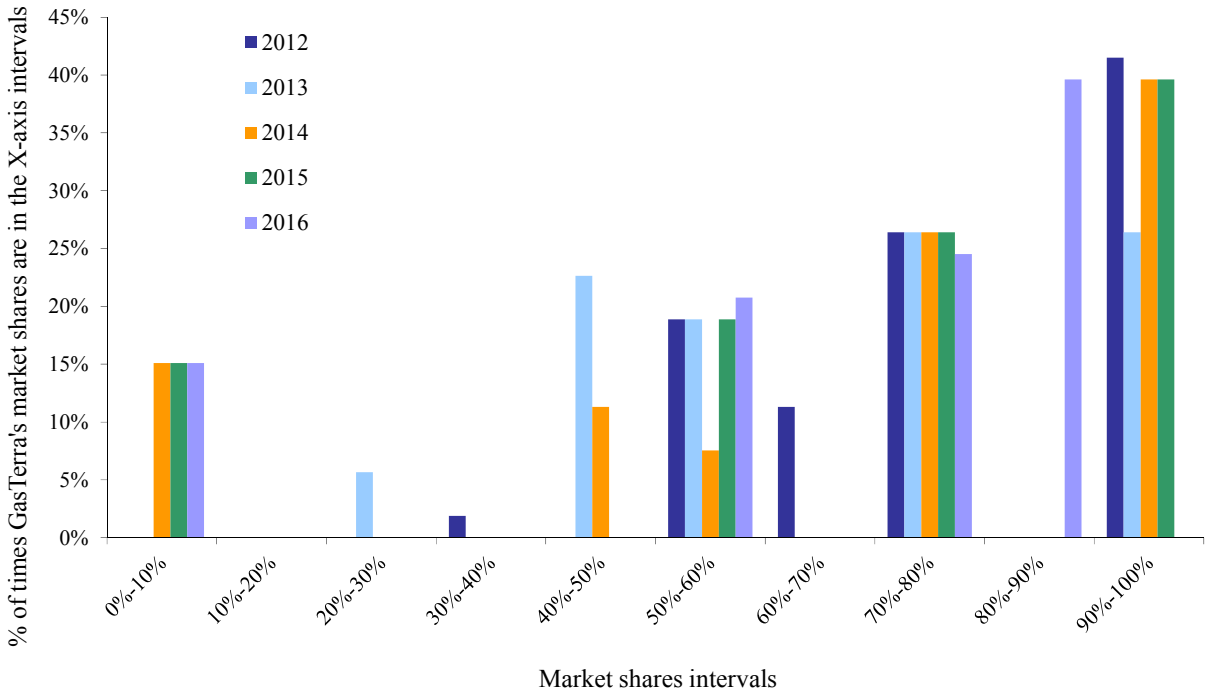



**Figure 11: Sub-market shares analysis, using weekly demand and weekly supply curves, all years**

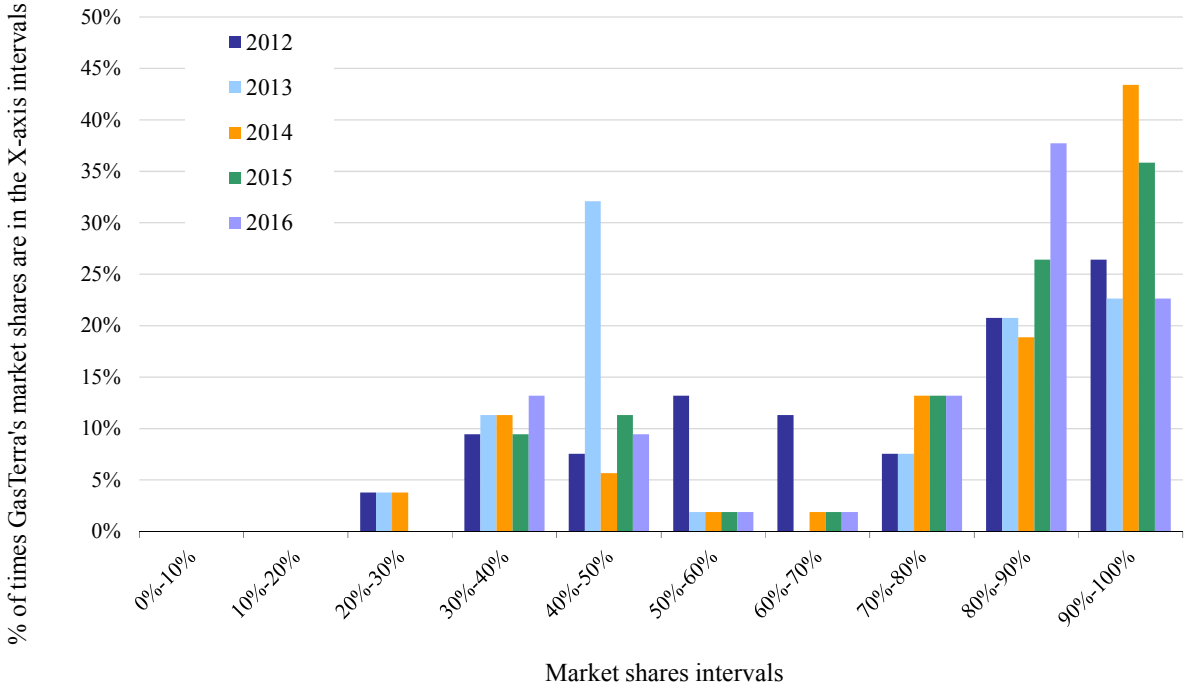


**Figure 12: Sub-market shares analysis, using the SSNIP test to define the relevant market and weekly supply curves (no other alternative assumption used), all years**

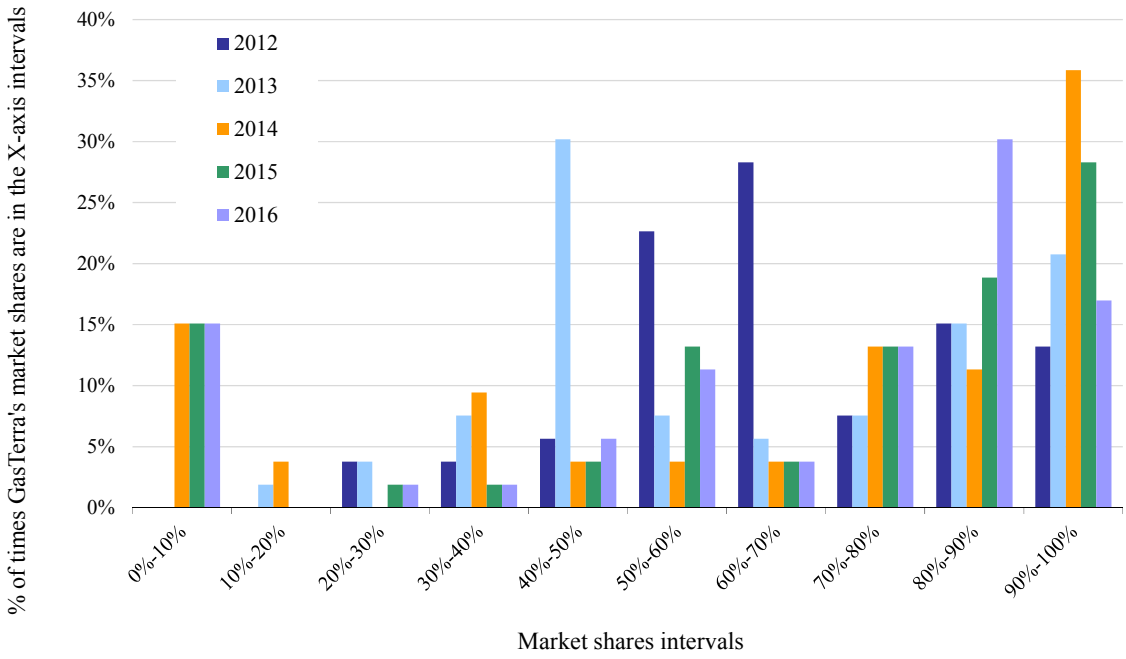



**Figure 13: Sub-market shares analysis, using variable costs instead of fixed plus variable costs, all years**

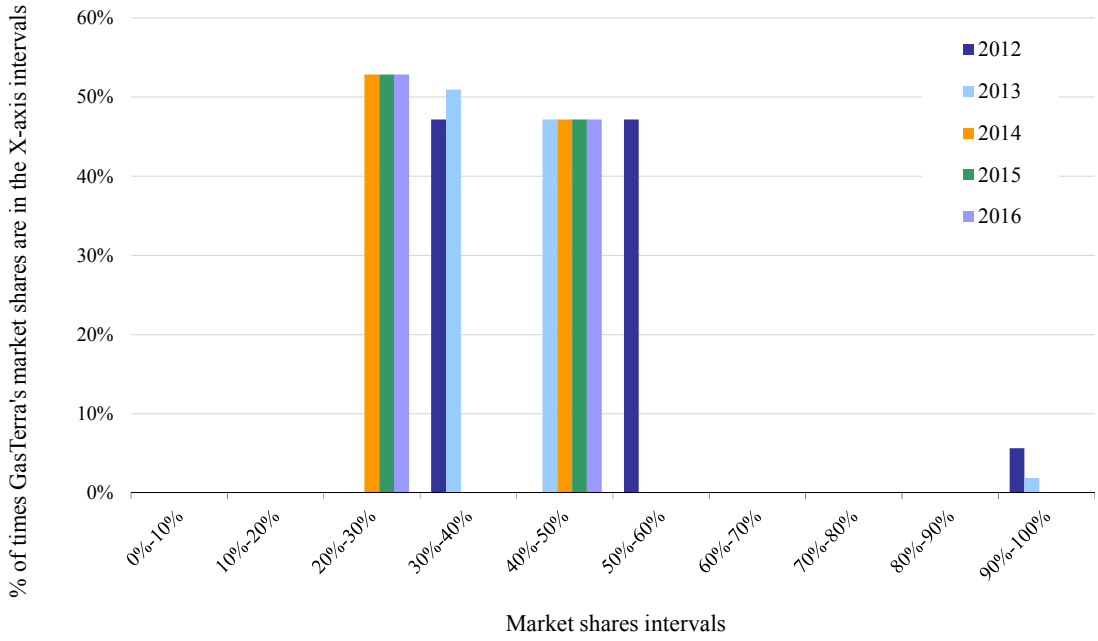
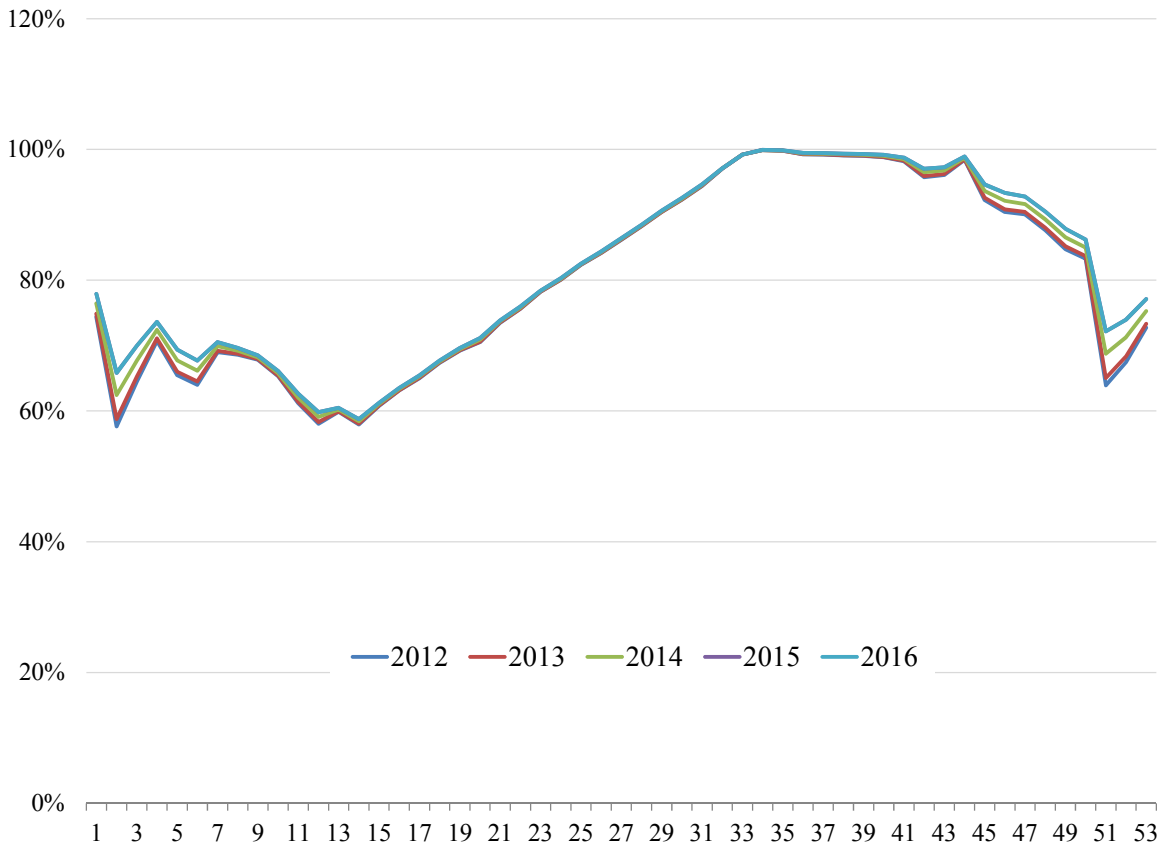


**Figure 14: Weekly adjustment factor for storage**




To compute the storage flexibility for each week, we multiply the nameplate maximum withdrawal capacity by the factors in Figure 14. The factors in Figure 14 account for two effects. First changes in maximum withdrawal capacity depending on how full the storage reservoir is. We estimate this effect using the withdrawal factor from GasTerra's virtual storage contract. Second, the variation in withdrawal from storage for each week. For example in winter storage will already be withdrawing gas, and so there will be less upward flexibility available. We use average weekly storage production from 2009 to compute the adjustment factors above.

**Figure 15: Weekly adjustment factor for production**