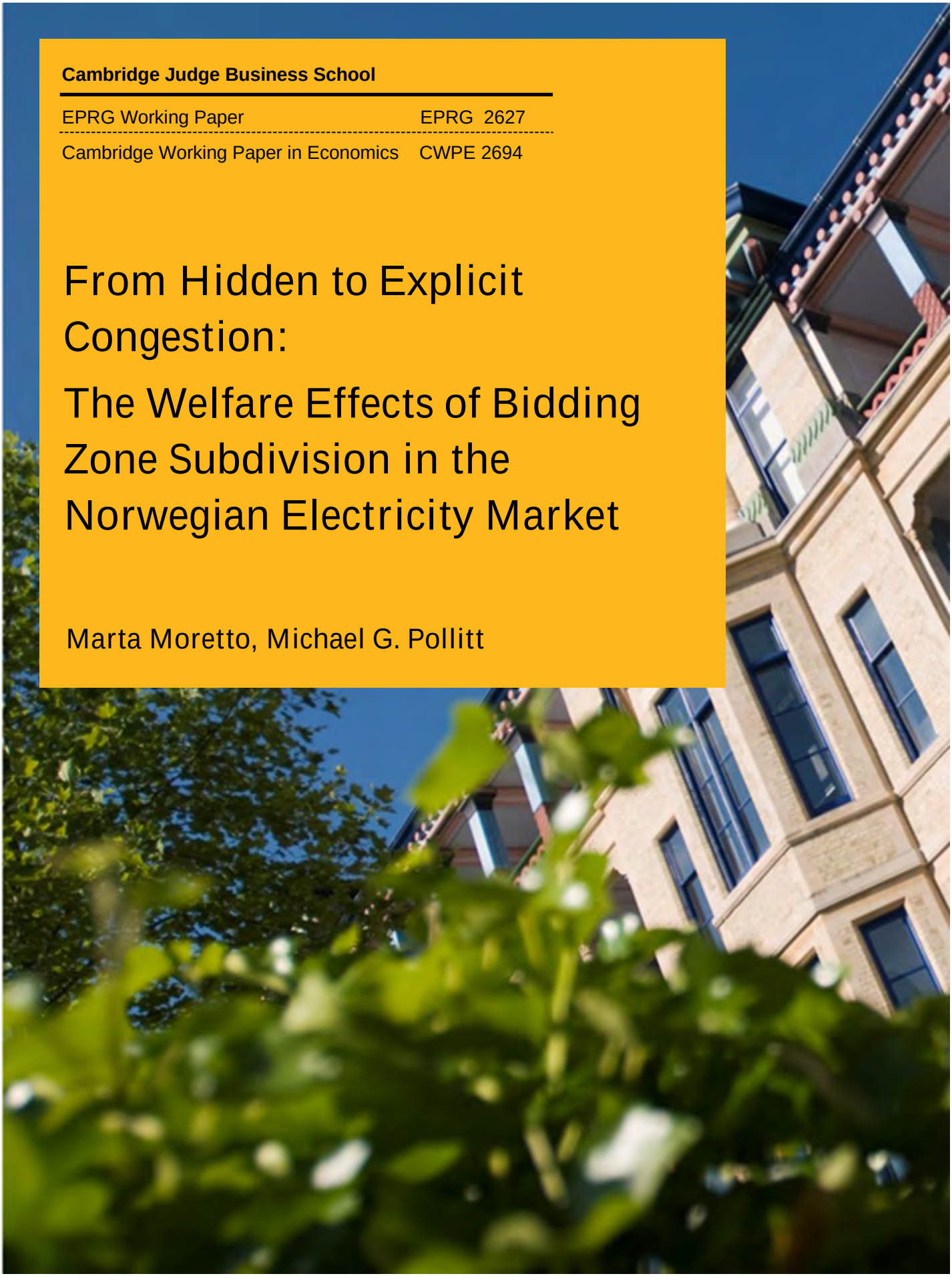

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From Hidden to Explicit Congestion:

The Welfare Effects of Bidding Zone Subdivision in the Norwegian Electricity Market

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Keywords : price granularity, price informativeness, allocative efficiency, market design, spatial price discovery, natural experiment, electricity markets

JEL Classification : D47, D61, L94, Q41, Q48

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Abstract

This paper asks whether increasing the number of bidding zones improves allocative efficiency by revealing spatial scarcity that a single price conceals, studying the welfare effect of greater price granularity. We study the Norwegian market reform of 13 April 2009, which divided the NO2 zone into NO2 and NO3, using hourly data and a difference-in-differences design against the unaffected zone NO1. The two zones had the same price in most hours after the reform; the split matters most in rare hours of severe local scarcity, such as 22 July 2009, when a single price would have masked the congestion in the opposite direction to that of other days. The allocative efficiency gain is positive, though small, approximately €146,000–165,000 per year (about 0.01% of the price of each MWh consumed in the affected zones) if such an episode recurs once a year. The main effect is distributional: the transfers between consumers and producers are much larger, about twelve times the gain in NO2 in absolute terms, and change sign between normal days and the episode. These results provide new evidence from an implemented reform to inform markets considering zonal pricing or additional zones, where assessments have so far relied mostly on simulations.

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1. Introduction

The welfare implications of price granularity are not straightforward: dividing a market into pricing areas may raise prices in some locations and lower them in others, but these changes are transfers between consumers and producers, not efficiency gains. Efficiency improves only to the extent that local prices reduce the underlying allocative distortion. Electricity markets provide a particularly clear setting, as electricity cannot be stored in large quantities, must be continuously balanced, and is transmitted through a network with finite capacity. When the transmission capacity between areas reaches its limit, electricity cannot

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flow freely from where it is abundant to where it is scarce and its marginal value may differ across places. The potential benefit of splitting the market is a reduction in the deadweight loss that arises when supply and demand in different sub-areas respond to the same price despite different local scarcity.

The granularity of market prices has become an increasingly relevant policy issue. Across Europe, regulators and transmission system operators have been reconsidering bidding-zone configurations that do not adequately reflect structural congestion. Much of the evidence informing these discussions comes from simulation models, and few studies (Loiacono et al., 2025; Fink, 2024; Wolak, 2011) examine reforms that have actually been implemented. In a static benchmark with price-taking participants and optimal zonal prices, Bjørndal and Jörnsten (2001) show that zoning cannot reduce social surplus, so the sign of the allocative effect is not in question; its size, and who gains or who loses, are empirical questions. This study addresses both for an implemented reform, asking how much allocative efficiency is gained when prices reflect local scarcity conditions that a common administrative price would otherwise hide.

The empirical analysis focuses on the Norwegian reform of 13 April 2009, which divided the NO2 area into a structurally importing area (the redefined NO2) and an exporting area (NO3), re-establishing a zone merged into NO2 in November 2008[1]. Here, "importing" and "exporting" refer to the zones' net electricity positions.

Our main specification is a difference-in-differences model on hourly data, estimated in a window of ±100 days around the reform, comparing the redefined NO2 and NO3 separately with the unaffected NO1. The two zones had the same price in 87% of hours after the reform, so the split has little effect on prices in most hours, but a large effect in the few hours of severe local scarcity.

On 22 July 2009, the price of NO2 remained between about €5/MWh for seven hours, while the price in NO3 fluctuated between €28 and €37/MWh. A single price would have hidden this congestion, which on other days runs in the opposite direction. We exclude this episode from the estimation of the price effect, but value it separately in the welfare analysis, since it generates much of the gain, and add it once to the other days valued at their average daily gain. The resulting allocative gain is modest, about €146,000–€165,000 per year (around 0.01% of the price of each MWh consumed in NO2 and NO3), about half of it from 22 July. This presumes that such an episode recurs once a year, which the data cannot verify. The transfers between consumers and producers are far larger than the gain, but they change sign between normal days and the episode, so that, over the year, net transfers are smaller than the absolute ones. The paper thus aims to show how the welfare effect of a zonal split can be measured from observed historical prices. Dynamic effects and the costs of market fragmentation are beyond our static analysis and left for future research.

The paper is organised as follows. Section 2 reviews the literature, Section 3 describes the Norwegian bidding-zone (BZ) structure, Section 4 presents the two-zone model, Sections 5 and 6 the data and the empirical strategy, Section 7 the results and Section 8 the welfare analysis, valuing separately the episode of 21–30 July. Section 9 concludes. Appendices A to E contain the supporting analyses.

2. Related literature

[1] Zone labels follow the Nord Pool areas in force in 2009 and differ from today's: NO1 covers southern Norway (Oslo, Bergen, Kristiansand), NO2 central Norway (Molde, Trondheim) and NO3 northern Norway (Tromsø). The current five zones, NO1–NO5, date from 15 March 2010. See Figure 1.

2.1. Market framework: prices, information and spatial equilibrium

A central question in spatial market design is whether prices convey the information needed for efficient allocation across locations. This is important when local market conditions are different and there are physical constraints on the movement of goods between areas.

Hayek (1945) provides an informational rationale for this role of prices: they economise on the knowledge required for efficient decentralised allocation by signalling changes in resource scarcity. When a uniform price applies across locations with different local conditions, it may fail to reflect information that a more granular price structure would convey.

Arrow and Debreu (1954) show that goods are defined partly by the conditions under which they are available, including their location. Samuelson (1952) and Enke (1951) then develop the implications for spatial price equilibrium.

In electricity markets, prices can differ across locations when transmission capacity is binding. When capacity is sufficient, these price differences tend to disappear. Importantly, whether a transmission constraint is physically binding does not depend on the pricing rule.[2] The pricing rule determines instead whether that constraint is reflected in prices or managed through an administrative mechanism. Pigou (1920) shows that congestion generates costs that should be reflected in prices when prices are to align private decisions with social marginal costs, while Vickrey (1969) emphasises that congestion varies across time and space, challenging the appropriateness of a single price where local conditions differ.

This congestion-pricing framework provides a useful starting point for the analysis: when transmission constraints are binding, more granular prices may better reflect local conditions and lead to a more efficient allocation across different areas.

2.2. Pricing granularity and the welfare trade-off

Market segmentation and differentiated pricing can have ambiguous welfare effects, as established in the literature on third-degree price discrimination. Classical contributions such as Pigou, 1920 and Robinson, 1933 show how the social welfare effect of the transition from uniform to differentiated pricing can be ambiguous. Price discrimination may expand aggregate output and total surplus relative to uniform pricing, especially when prices better reflect differences in demand. However, this effect depends on the cost structure. Schmalensee (1981) shows that higher total output is a necessary condition for any welfare gain, while Varian (1985) and Aguirre et al. (2010) show that the welfare consequences of discrimination hinge on the shape and curvature of demand across segments.

More recently, Bergemann et al. (2024) similarly show that the welfare effects of market segmentation depend on the allocation induced across segments. Unlike discrimination based on demand elasticity, the spatial equilibrium mechanism of Enke (1951) and Samuelson

[2] As an approximation we consider congestion as exogenous. However, studies such as Mirza and Bergland (2015) find that, in some hours, producers in southern Norway limit production to induce import congestion in their area, and Bjørndal et al. (2003) demonstrate that the choice between zonal prices and counter-trading offers the operator and market participants incentives to change where it is operated. Congestion is therefore not always independent of congestion management behaviour or rule. We discuss the implications for identification in Section 6.4.

(1952) ties price divergence to a binding physical transfer constraint, so that its suppression under a uniform price is itself a source of inefficiency.

Greater granularity also has costs. Smaller markets may increase the scope for local market power where competition is constrained by the network (Borenstein et al., 2000; Joskow and Tirole, 2000), and may reduce liquidity, making hedging and risk management more difficult (Glachant and Rossetto, 2018; Hary, 2018; Laur and Küpper, 2020).

Price granularity therefore trades off more accurate local price signals against the costs of thinner markets and greater local market power. Joskow and Tirole (2005) further show that congestion pricing can affect longer-term transmission investment incentives.

2.3. Spatial pricing in electricity markets

Holahan (1975) analyses the welfare effects of spatial price discrimination and demonstrates that geographically differentiated prices can improve allocation when uniform prices fail to reflect spatial differences in supply costs. In electricity markets, transmission constraints make the marginal value of electricity location-specific. Schweppe et al. (1988) develop the conceptual basis for locational marginal pricing, in which prices reflect generation costs, transmission losses and network congestion across time and space.

The Nordic literature addresses zonal pricing directly. Using stylised network examples, Bjørndal and Jörnsten (2001) show that zonal pricing redistributes surplus between producers, consumers and the grid company; that the allocation of nodes to zones determines this distribution, with producers and consumers preferring opposite allocations in their examples; and that a finer zonal splitting cannot reduce social surplus when zonal prices are optimal. Bjørndal et al. (2003) describe the Nordic system, in which inter-zonal constraints are priced through zones and intra-zonal ones are managed through counter-trading, and show that the method used to manage a given constraint changes prices and the surplus of each agent, including the system operator. In a model of England and Wales, Green (2007) estimates that moving from uniform to optimal prices would raise welfare by 1.3% of revenue, while consumer surplus would rise by 3.4% and generator profit fall by 2.1% of revenue. For the Nordic market, a principal-model analysis finds that changing the number of BZs, relative to the practice at the time of resolving internal congestion through capacity restrictions, yields modest socioeconomic benefits, with winners and losers among consumers and generators and across countries (Electricity Market Group, 2008, p. 11).

Recent applied studies show that welfare effects depend on how market boundaries are designed. Czock (2025) finds that alternative configurations of the German electricity market generate different welfare outcomes and shows that greater segmentation is not necessarily welfare improving. Similarly, simulations of zonal reform in Great Britain suggest potentially large welfare gains from more spatially differentiated prices, although these depend on the configuration considered (FTI Consulting, 2025).

The choice of spatial granularity thus concerns more than the number of zones, as it determines the level at which scarcity information enters market prices. Nodal pricing represents the most granular version of this principle: prices adjust to local network conditions at individual nodes, as opposed to zonal systems which aggregate several locations under a common price, requiring administratively defined boundaries. Therefore, when these boundaries cease to reflect persistent congestion patterns, prices may become less informative and periodic reconfiguration may be necessary. Hence, the welfare case for

greater granularity is therefore conditional and not universal, as clarified by the evidence above.

A smaller number of studies directly analyse the impact of market reconfigurations. Loiacono et al. (2025) examine Sweden's 2011 transition from a single national zone to four BZs, finding that prices rose and diverged across zones in line with underlying differences in production costs. Katzen and Leslie (2024) measure the pricing error generated by Australia's zonal market relative to shadow locational marginal prices and examine its implications for renewable investment incentives. For California, Wolak (2011) estimates that the switch from zonal to nodal pricing happened in April 2009 reduced the variable cost of natural gas-fired generation by about 2.1%, a cost-based measure of the benefit of greater spatial granularity that also reflects start-up decisions. Boeschemeier and Neuville (2026) use simulated nodal prices for Europe to identify zonal configurations that minimise the within-zone variation of nodal prices, and hence total operating costs. For Germany, an optimally drawn two-zone split achieves about two-thirds of the cost reduction obtained under full nodal pricing. Adding more zones results in progressively smaller cost reductions.

This paper contributes to the small empirical literature on implemented bidding-zone reforms (Loiacono et al., 2025) by extending the analysis from price effects to welfare implications. It also complements simulation-based assessments of alternative zonal configurations (FTI Consulting, 2025; Boeschemeier and Neuville, 2026) with ex post evidence from an implemented reform.

3. The Norwegian electricity market as a natural laboratory: Institutional framework and zonal reforms

The main source of electricity generation in Norway is hydropower, which accounts for approximately 89% of total generation (IEA, 2025). A distinctive feature of Norwegian hydropower is the large storage capacity of its reservoirs, enabling water to be stored and generation to be distributed over time in line with demand, inflows and forecasts of future prices. This flexibility makes reservoir conditions an important determinant of electricity supply and, therefore, prices.

At the same time, hydropower resources are geographically concentrated, while demand for electricity is spread throughout the country. A well-developed transmission network is therefore necessary to channel electricity from areas with a surplus of generation to those with higher demand (Energy Facts Norway, 2025). When transmission capacity becomes binding, these geographical differences can translate into persistent differences in local scarcity conditions and provide an economic rationale for spatially differentiated prices.

3.1. The structure of the zonal market

Norway has an electricity market currently organised into five distinct BZs: Eastern Norway (NO1), Southern Norway (NO2), Central Norway (NO3), Northern Norway (NO4) and Western Norway (NO5) (Statnett, 2025a). The current structure is the result of a series of boundary adjustments introduced progressively to better reflect transmission constraints and regional grid conditions.

The Norwegian electricity market as we know it today was created by the reform introduced by the 1990 Energy Act, thanks to which Norway became one of the first countries to liberalise its electricity sector. As part of this reform, Norway began operating with flexible,

temporary zones from 1991 onwards, but it was not until 2008 that its market structure was formalised into a zonal pricing system, with the number of BZs gradually increasing.

Since then, congestion management has been implemented through geographically defined bidding zones within the market (NVE, 2012). Under this principle, a common day-ahead price applies within each zone, while electricity exchanges across zone boundaries are limited by available transmission capacity. When such constraints arise, zone prices may diverge, allowing prices to reflect differences in local supply, demand and scarcity conditions.

Congestion within an existing zone can be handled in three ways: by splitting the zone, so that the constraint is reflected in prices; by counter-trading, in which the system operator, after the day-ahead auction, buys and sells regulating power on either side of the constraint; and by reducing the transmission capacity offered to the market (Mirza and Bergland, 2015). In Norway, counter-trading of intra-zonal congestion is known as special regulation (*spesialregulering*). It leaves the day-ahead price unchanged but its costs fall on the operator and, through it, on grid users, and the choice among these methods changes prices and the surplus of each agent, giving both the operator and market participants an incentive to influence it (Bjørndal et al., 2003). Where congestion is anticipated, counter-trading may also lead to more strategic bidding and less efficient use of resources than market splitting, while allowing fewer and larger price areas that favour retail competition; the balance has to be assessed case by case (Electricity Market Group, 2008, p. 11). Statnett's special regulation costs were NOK 117 million in 2008 and NOK 153 million in 2009 (Statnett, 2009, p. 59).[3] These figures refer to the whole national grid.[4]

The configuration of Norwegian BZs has changed over time, moving progressively from two to five zones, as shown in Figure 1. In the configuration relevant to this study, NO1 included Oslo, Bergen and Kristiansand, while the old NO2 comprised Molde, Trondheim and Tromsø (Nord Pool, 2015). On 13 April 2009, Tromsø was separated from the old NO2 and became a distinct BZ, NO3, leaving Molde and Trondheim within the redefined NO2. Statnett justified the split due to low reservoir levels in central Norway and a temporary reduction in import capacity during the construction of a new 420 kV line between central Norway and Sweden, which could cause congestion (Nord Pool, 2015). Before the reform, the Norwegian market was divided into two supply areas, with the system operator able to define additional areas in periods of significant and long-lasting bottlenecks. In November 2006, in response to low reservoir levels in central Norway, Statnett divided the NO2 zone into central (NO2) and northern (NO3) Norway, the same configuration studied in this study. However, before the 2009 reform, the two zones were merged again on 17 November 2008 when the hydrological situation improved (Sandsmark, 2009). The central region is structurally in deficit: in 2006 its three counties produced 13.5 TWh and consumed 19.1 TWh; the deficit was expected to rise to 8 TWh by 2010 due to the expansion of energy-intensive industry (Sandsmark, 2009). For clarity, the zone names used in this study follow the 2009 configuration: NO1 corresponds to the current NO1, NO2 and NO5, NO2 redefined to the current NO3 and NO3 to the current

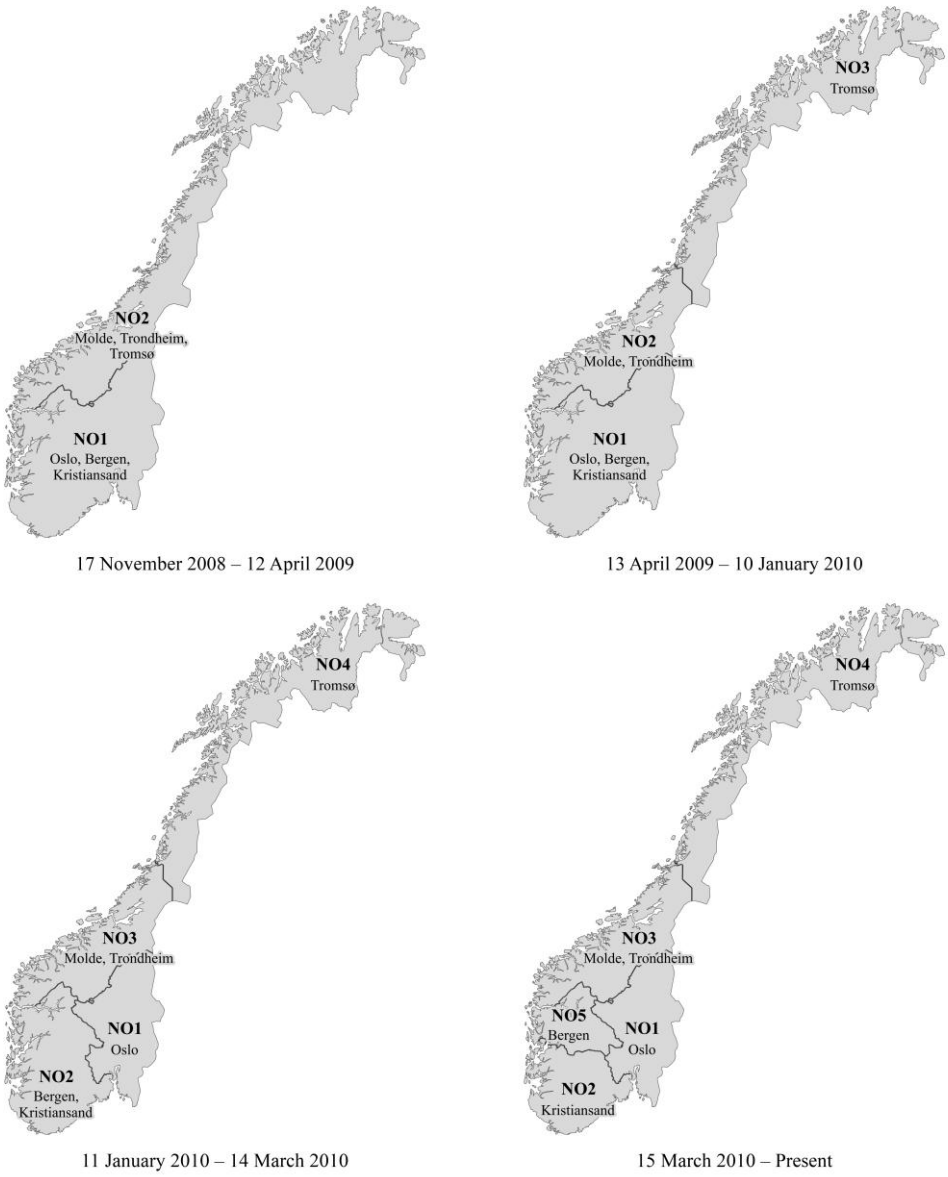
[3] These figures are Statnett's payments and not the social cost of special regulation, which is the efficiency loss from forcing producers away from their optimal production plans and is often only a small part of that expense (NVE, 2024).

[4] The available sources do not allow us to isolate the part attributable to Central Norway, nor to establish how the constraint was managed before April 2009. Bjørndal et al. (2003) themselves note that assessing the exact cost to society requires modelling how counter purchases are carried out. We therefore cannot quantify counter-trading costs in the old NO2 (see Section 4.2.4).

NO4. The three-zone structure remained in place until 11 January 2010. Subsequent reforms eventually produced the five-zone configuration currently in place.

Figure 1

Norwegian Market Zones: Sequence of Reforms



Source: Authors' elaboration based on ENTSO-E bidding zone geometries (entsoe-py) and Natural Earth.
Note: Map lines delineate study areas and do not necessarily depict accepted national boundaries.

Norway provides an excellent example for observing the effects of the reconfiguration of BZs over time. This reconfiguration represents a dynamic and necessary approach to ensuring the efficient use of the hydroelectric system and the transmission grid over the years. However, Energy Norway (2013) has pointed out that not only the division but also the merging of zones, even across national borders, should be addressed. The Norwegian case suggests that, in the absence of frequent structural congestion and where price differences are minimal, the cost of counter-trading operations may be lower than the benefits that a

larger zone would bring to market development, although the balance has to be assessed case by case (Electricity Market Group, 2008, p. 11).

The definition of BZ boundaries is therefore an economically important market design choice. Zones that are too large may have persistent internal congestion that is not reflected in market prices. As a result, prices may provide less information about local conditions to generators and consumers. Greater spatial granularity, on the other hand, can improve these price signals, but may also reduce market liquidity and increase the scope for local market power, as discussed in Section 2. What matters is whether the geographical boundaries reflect persistent differences in network and market conditions (Moretto and Pollitt, 2026).

Statnett's long-term market analyses monitor the evolution of the Norwegian electricity system, including price differences between bidding zones and the need for infrastructure upgrades between regions (Statnett, 2025d). A recent example involves northern Norway (NO4): with increasing internal congestion, Statnett is considering whether to further subdivide the zones to better reflect local grid conditions in market prices (Statnett, 2025b). Statnett also evaluated changes to the boundary between NO1 and NO2 and different ways of managing bottlenecks within NO2. It concluded that the existing configuration was still adequate given expected changes in consumption and generation and planned grid modernization (Statnett, 2025c). The analysis also found that a coarser configuration with fewer zones would make congestion management more difficult, reduce the efficient use of energy resources, and weaken locational price signals. These assessments run in parallel with the broader European Bidding Zone Review process (European Commission, 2015, Arts 32–34), where alternative configurations are considered in terms of network constraints, economic welfare, competition, and market functioning. Therefore, the Norwegian case shows that zone boundaries are not fixed. They may need to change as economic and transmission conditions evolve.

4. Estimating social welfare

4.1. Congestion, hidden costs and the problem of a single price

In zonal power markets, a single price for a large area may not reflect local supply and demand conditions. If electricity cannot flow freely between BZs with excess generation and, consequently, lower prices to others with more limited supply and higher price, that means that congestion problems are at play. Unpriced congestion is a source of economic inefficiency, because some of the low-cost power generation is unable to reach the consumers in the constrained supply area, then the local market must instead be supplied by higher-cost supply, or demand will not be met.

Building on the spatial equilibrium mechanism established in Section 2, Hogan (1992) demonstrates in the specific context of nodal electricity markets that, with binding transmission constraints, the socially optimal allocation requires each node to find an equilibrium at its own locational marginal price (LMP). A zonal system approximates this principle by grouping several locations under a common price. The economic performance of the system, therefore, depends on whether zonal boundaries adequately capture persistent congestion patterns.

The 13 April 2009 Norwegian reform provides a concrete case. Before the reform Molde, Trondheim and Tromsø belonged to the old NO2 and were subject to the same zonal price despite obvious differences in their underlying supply and demand conditions. The reform

separated the importing area, represented by the new NO2, from the more generation-abundant NO3 area. This, in turn, allowed spatial differences in scarcity to be reflected in market prices through separate zonal prices.

Before the split, a single price for NO2 hides the scarcity created by a binding internal constraint: the planned flow from the generation-rich north exceeds the interface capacity, and the excess is resolved outside the price (for instance by counter-trading or capacity reduction), so that the single price departs from the local scarcity value in each sub-area.

The welfare effects of zonal reforms can be decomposed into changes in consumer surplus, producer surplus, and two further components that must be kept conceptually distinct: a price-quantity trade residual (measured on pre-reform quantities) and, separately, the congestion income generated by observed post-reform physical flows across constrained boundaries — the latter conventionally included, alongside consumer and producer surplus, in the European market-coupling definition of social welfare (NEMO Committee, 2020).

Allowing the two areas to clear at different prices makes the constraint explicit and can reduce allocative distortions created by misaligned economic incentives: in the importing area, a price below the local scarcity value can discourage marginal production and encourage inefficiently high consumption, to the benefit of consumers, while the opposite distortion may arise in the exporting area. The welfare gain associated with the reform therefore arises not from price differentiation itself, but from the extent to which differentiated prices enhance the allocation of production and consumption across space. Price differentiation may also generate revenues associated with electricity exchanged across zones with different prices. However, these revenues depend on both price differentials and physical flows and should be distinguished from the consumer and producer surplus effects. Accordingly, the empirical welfare analysis below separately reports the redistribution of surplus and the estimated efficiency effect of the reform.

4.2. From price effects to welfare measurement

4.2.1. What the price regression identifies

Let be $t = \{pre, post\}$ as the period before and after the reform. In the economic theory of Difference-in-Difference, we define for every hour t after April 13, 2009, the observed prices $P_{2,t}, P_{3,t}, P_{1,t}$, for zones NO2, NO3 and NO1 respectively. We also define the price that would have formed if NO2 and NO3 had remained a single zone (i.e. in the absence of the reform), an unobservable counterfactual price, called P_t^0. Before the reform it coincides with the observed prices of NO2 and NO3, $P_t^0 = P_{2,t} = P_{3,t}$. With NO1 as control, the DiD coefficient for zone $i \in \{2, 3\}$ is the double difference of means:

$$\beta_i = \left[E_{post}[P^0] - E_{post}[P_1]\right] - \left[E_{pre}[P^0] - E_{pre}[P_1]\right] \qquad (4.1)$$

Because the two treated zones shared one price before the reform, the second bracket is the same for $i = 2$ and $i = 3$.

Define the effect of the split on zone i in hour t as the difference between the world we observe and the world without the reform:

$$a_i = P_{i,t} - P_t^0 \qquad (4.2)$$

Substituting $P_{it} = a_{it} + P_t^0$ into (4.1) and collecting terms gives:

$$\beta_i = E_{\text{post}}[a_i] + c, \qquad c \equiv E_{\text{post}}[P^0 - P_1] - E_{\text{pre}}[P^0 - P_1] \tag{4.3}$$

The term c measures the change in the price gap between the former NO2 (as a single zone) and NO1 between the two periods, regardless of the reform. A standard DiD assumes $c = 0$ (parallel trends) and reads β_i as the total effect of the reform. Equation (4.3) is an identity: it follows from the definitions of a and c and involves no behavioural assumption.[5]

Since P^0 and the control are the same for both zones, c does not depend on i. Subtracting, P^0 cancels:

$$\beta_2 - \beta_3 = E[a_2 - a_3] = E[P_2 - P_3] \equiv E[s] \tag{4.4}$$

The difference between the two coefficients equals the mean post-reform spread between the two zones, whatever control is used. In estimation, with covariates that differ by zone, the equality holds up to those covariates; Section 6 reports the comparison. Equation (4.4) does not identify a_2 and a_3 separately: it is one equation in two unknowns. An economic assumption is needed.

4.2.2. Market clearing and the split of the spread

We make three assumptions. (A1) Bids do not change with the reform, so the same net-demand curves apply before and after. (A2) Only the NO2–NO3 interface changes: the exchange of the former NO2 with the rest of the system is unchanged. (A3) Net demand is linear around the pre-split price, as first order approximation used only for (4.7) and (4.9).[6]

Let $E_i(P) = D_i(P) - S_i(P)$ be the net demand of zone i, net of its exchange with the rest of the system, which A2 holds fixed. With a single zone the market clears at P^0, so $E_2(P^0) + E_3(P^0) = 0$. After the split, whatever NO2 imports across the interface must be exported by NO3. Let F be the physical flow from NO3 to NO2, so that $E_2(P_2) = F$ and $E_3(P_3) = -F$. Under A3, demand is linear around P^0, with $K_i = -E_i' > 0$ as its slope,

$$K_i = \frac{\varepsilon_s S_i + |\varepsilon_d| D_i}{P} \tag{4.5}$$

where S_i and D_i are zonal supply and demand, ε_s and ε_d the price elasticities of supply and demand, and P the price at which the slope is evaluated (the observed zonal price of the hour in our implementation). Then $E_i(P_i) \approx E_i(P^0) - K_i a_i$. Adding the two post-split conditions and using the pre-split balance gives

$$K_2 a_2 + K_3 a_3 = 0 \tag{4.6}$$

Equation (4.6) says that the flow NO2 receives is the same flow NO3 loses. If the interface binds, with planned flow $F^0 = E_2(P^0)$ above capacity $\bar{F}$, then $K_2 a_2 = -K_3 a_3 = \Delta F \equiv F^0 - \bar{F}$, which is the representation used in Figure 2.

Using $s = a_2 - a_3$ from (4.4) to eliminate one unknown,

[5] Term c collects change in hydrology, demand, fuel, import prices and any spill-over of the reform onto NO1 itself, which is interconnected with the treated area and is therefore not a perfectly clean control.

[6] The identity (4.4) and the bounds (4.8) require only that net demand is decreasing in price.

$$a_2 = \frac{K_3}{K_2 + K_3}\, s = w\, s, \qquad a_3 = -\frac{K_2}{K_2 + K_3}\, s = -(1 - w)\, s \tag{4.7}$$

The weight w is high when K_3 is high relative to K_2, that is, when NO3's net demand responds strongly to price. The price then moves mostly in NO2: the zone with the less price-responsive net position bears the larger price change. The sign of a_2 is the sign of s, while a_3 has the opposite sign: when $s > 0$ the price of NO2 rises and that of NO3 falls.

4.2.3. Bounds and sensitivity

Since $K_i > 0$, $w \in (0,1)$. When $s > 0$, $a_2 \in [0, s]$, and when $s < 0$, $a_2 \in [s, 0]$. Averaging over hours, with $s^+ = \max(s, 0)$ and $s^- = \max(-s, 0)$,

$$E[a_2] \in \left[-E[s^-],\ E[s^+]\right], \qquad E[a_3] \in \left[-E[s^+],\ E[s^-]\right] \tag{4.8}$$

These bounds hold whatever the elasticities. For NO2 they are $[-0.04, 0.22]$ €/MWh. The central estimate $E[w_t s_t] \approx$ €0.12/MWh requires the weights, which depend only on the ratio $K_3/(K_2 + K_3)$ and not on the level of the elasticities; across the nine combinations of the elasticity grid of Section 6.3 the central estimate lies between 0.113 and 0.118.

The bounds also imply a lower bound on the non-attributable component. Since $E[a_2] \leq E[s^+]$, equation (4.3) gives $c \geq \beta_2 - E[s^+]$, which is $0.898 - 0.223 =$ €0.68/MWh in the reference specification. This does not rely on the elasticities, only on $K_i > 0$ and A1–A3.

Our weights assume the same elasticities in the two zones, so K_i differs only through volumes. If the zones differ, $E[a_2]$ stays roughly between 0.06 and 0.12 for $K_3 = K_2/2$ ($w = 1/3$) and $K_3 = 2K_2$ ($w = 2/3$), with $E[s] = 0.18$. Plausible heterogeneity therefore keeps the price effect of the split below about 13% of $\beta_2 = 0.898$. The price effect of the split is robustly a small share of the total.

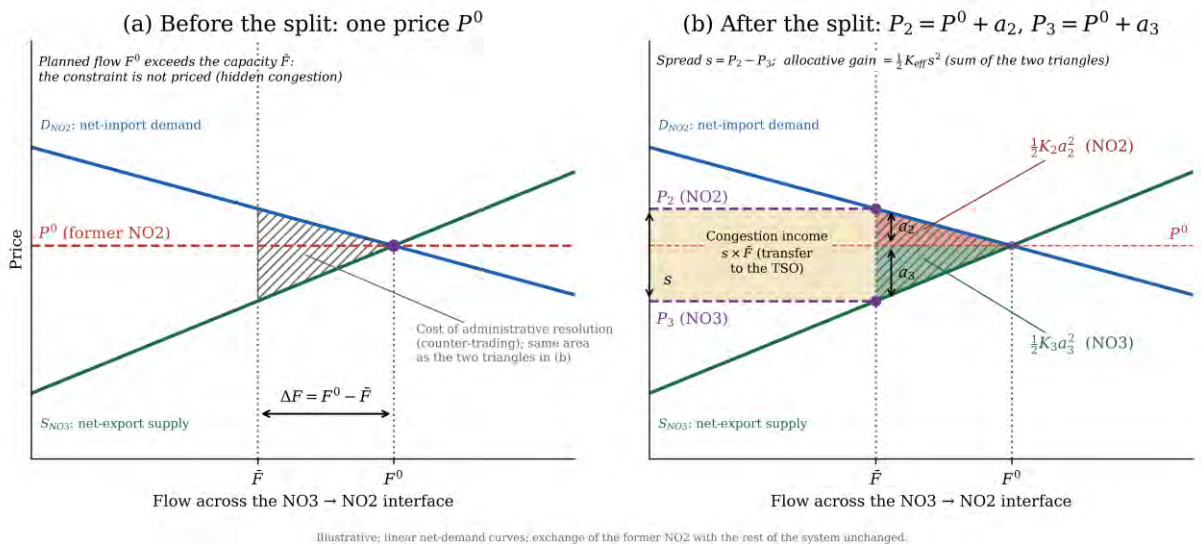
4.2.4. Welfare

In each zone the deadweight loss removed is the triangle $1/2\, K_i a_i^2$, that is, half the slope of net demand times the squared price effect (Harberger, 1954; Varian, 1992). Summing the two zones and substituting the weights,

$$DWL_t = \frac{1}{2}[K_2 w^2 + K_3(1 - w)^2] s_t^2 = \frac{1}{2}\frac{K_2 K_3}{K_2 + K_3}\, s_t^2 = \frac{1}{2} K_{\text{eff}}\, s_t^2 \tag{4.9}$$

where K_{eff} is the slope of the two zones across the interface. Here DWL_t is also equal to $1/2\, s_t \Delta F_t$. Because it is quadratic in s, it is driven by the few hours with a large spread (the spread is zero in 87% of the post-reform hours; its 99th percentile is €6.6/MWh and its maximum €29.2/MWh). To first order, consumers in zone i lose $a_i D_i$ and producers gain $a_i S_i$; across the two zones these transfers sum to $-s\bar{F}$, the congestion rent collected by the system operator, which is a transfer and not an efficiency effect.

Figure 2.
Stylised two-zone clearing at the NO2–NO3 interface.



Note: Before the split, a single price P^0 clears the former NO2 and the planned flow F^0 exceeds the capacity $\bar{F}$; the congestion is not priced. (b) After the split, prices diverge ($P_2 = P^0 + a_2$, $P_3 = P^0 + a_3$, spread $s = a_2 - a_3$), the interface carries $\bar{F}$, and the congestion income $s \times \bar{F}$ accrues to the system operator. The shaded triangles are the allocative gain. Illustrative: linear net-demand curves; the exchange of the former NO2 with the rest of the system is unchanged.

Figure 2 illustrates these relations. Panel (a) shows the situation before the split: one price P^0, a planned flow F^0 above capacity, and a hatched triangle of height s and base ΔF. Panel (b) shows the situation after: the interface carries $\bar{F}$, NO2 clears at $P_2 = P^0 + a_2$ and NO3 at $P_3 = P^0 + a_3$, and the rectangle $s \times \bar{F}$ is the congestion income. The two shaded triangles are the allocative gain in (4.9); their sum equals the hatched triangle in (a).

The figure is stylized: it draws s ≥ 0, whereas in the data s is positive in about 7% of the post-reform hours, negative in about 5% and zero in the remaining 87%. A negative spread means that the price of NO3 exceeds that of NO2; since the transfer capacity from NO2 to NO3 is zero in every hour of the sample, the interface cannot mitigate such scarcity, and the same clearing logic applies when the roles of the two zones reversed and the spread is positive. Identity (4.4) holds regardless, but the split $a_2 = ws$ in (4.7) is imposed, not observed, with the bounds (4.8) reported in Section 7.2 alongside the point values; the weights depend on K_i, which are calibrated from elasticities found in the literature; Section 8 reports the results over a grid. The framework measures only the gain from this subdivision: any distortion remaining inside the redefined zones is not accounted for. This estimate is conditional on s, K_i and A1–A3. Prior to the reform, the internal constraint on NO2 was presumably managed through counter-trading or capacity reduction. If these instruments had already driven production efficiently, some of the supply-side gain would have been realised before the reform, and the estimate would overestimate the additional gain from the division of the zone. Conversely, the costs of these instruments, which the split may have reduced, are not recognised in (4.9). The supply-side triangle is therefore either an allocative gain or an avoided counter-trading cost, never both. The demand-side component, which is much smaller, does not depend on how production was distributed; we report it separately in Section 8.1.

5. Data and sample

The analysis draws on two main data sources. The first is the Nord Pool Market Data API v2 (Nord Pool, 2026), which provides hourly zonal prices (€/MWh), zonal consumption and generation (MWh), as well as interzonal flows and transmission capacities for the Norwegian areas and the Danish zone DK1. DK1 serves as an additional market control, tracking price changes common to the Nord Pool system that are not directly affected by the Norwegian zonal reform. It is a daily price assigned to each hour of the day and enters with a common coefficient.

The second source is the NVE Magasinstatistikk portal (NVE, 2026), which reports the weekly levels of the reservoirs in the Norwegian hydropower system, mapped to each hourly observation. The resulting variable fill ratio is the aggregate reservoir fill (TWh) divided by the historical median for the same ISO week, so that a value of one denotes a median level. Reservoir statistics are published by current price area (NO1–NO5), which differ from the 2009 zones, so we aggregate them as ratios of sums: the 2009 NO1 corresponds to the current NO1, NO2 and NO5; the 2009 NO2 (Central) to the current NO3 and the former NO2 to the current NO3 and NO4 together. The weekly value is assigned to every day, and hence to every hour, of the corresponding ISO week. The reference specification uses the fill ratio of the Centre for both treated zones and that of the South for NO1; the alternatives are reported in Appendix B.

Descriptive statistics for the principal variables before and after the reform are reported in Table 1.

Table 1.
Pre- and post-reform descriptive statistics

Variable	Pre-reform	Post-reform	Δ	Unit
P_{NO2} (day-ahead price, NO2; former NO2 before the reform)	37.857	35.180	−2.677 (−7.1%)	€/MWh
P_{NO3} (day-ahead price, NO3; former NO2 before the reform)	37.857	34.997	−2.860 (−7.6%)	€/MWh
P_{NO1} (day-ahead price, NO1)	37.396	33.658	−3.738 (−10.0%)	€/MWh
P_{DK1} (Danish reference price)	38.020	34.667	−3.352 (−8.8%)	€/MWh
Price difference NO2 − NO1	+0.461	+1.522	+1.061	€/MWh
Price difference NO3 − NO1	+0.461	+1.339	+0.878	€/MWh
Spread s = NO2 − NO3	0	+0.183	+0.183	€/MWh
Share of hours with equal NO2 and NO3 prices	100%	87.5%		%
Reservoir fill ratio, Central Norway (reference series)	0.839	0.888	+0.049	ratio

Variable	Pre-reform	Post-reform	Δ	Unit
Reservoir fill ratio, Southern Norway (reference series)	0.903	0.950	+0.047	ratio
Reservoir fill ratio, former NO2 (Centre and North)	0.960	0.970	+0.010	ratio

Note: Reform date: 13 April 2009. Pre-reform window: 3 January – 12 April 2009; post-reform window: 13 April – 22 July 2009. The table reports means of daily averages over the respective windows; the post-reform window excludes 21 and 22 July 2009. Hours: 2,399 pre-reform and 2,376 post-reform. Econometric estimation is carried out on the same hourly sample ($N = 4.775$ per zone). The DK1 price and the reservoir fill ratios enter the regressions in standardised form (zero mean, unit standard deviation). Reservoir series are defined in Section 5.

The estimation window is ±100 days around the reform of 13 April 2009, from 3 January to 22 July 2009, with NO1 as control. The treated zones are NO2 and NO3; each is stacked with NO1 in a separate panel, and a third panel uses the spread between NO2 and NO3 against zero. The raw window contains 4,823 hourly observations per zone. The main sample excludes 21-22 July 2009, the part inside the window of an episode of large NO2–NO3 spreads that runs from 21 to 30 July[7]. Episodes are identified by a rule: a run of days in which the absolute daily mean of the spread is at least €1/MWh, with consecutive active days separated by at most one quiet day. The exclusion leaves 4,775 observations per zone and applies to the regressions and the descriptive statistics, where these days with large price differences of opposite sign would drive the average price effect. The episode is not excluded from the welfare analysis: it is valued separately from observed prices, which requires no regression, and added once to the annual gain (Section 8.1). The annual figures of Section 8 use a sample extended to 10 January 2010, the last day of the three-zone configuration. As the exclusion was decided after observing that these days are influential, Section 7.5 reports the results with 22 July excluded alone and with no exclusion for robustness.

6. Empirical methodology

6.1. Empirical strategy

The reform of 13 April 2009 split the former NO2 into the redefined NO2 and NO3. The empirical analysis answers three questions in sequence. First, how did the price of each new zone change relative to an unaffected zone? This is measured by two difference-in-differences (DiD) regressions, one for NO2 and one for NO3, both with NO1 as control (Section 6.2). Second, how much of that change is attributable to the split itself? As shown in Section 4.2.1, the DiD coefficient combines the effect of the split with a common component c; the attributable part is recovered from the observed price difference between the two new zones and the market-clearing condition (Section 6.3). Third, which allocative gain and which transfers follow from the attributable price effects (Section 8)?

6.2. Difference-in-differences specification

[7] On 22 July 2009 the price in the redefined NO2 fell to 4.81–6.04 €/MWh for seven consecutive hours, while NO1 remained within its usual range (€28–€35/MWh). The NO2–NO1 difference reaches −€28.91/MWh in the most extreme hour, the largest hourly difference of the post-reform sample, and the daily mean is −€15.98/MWh.

For each treated zone $i \in \{2,3\}$ (NO2, NO3) we stack the hourly day-ahead prices of the zone $j \in \{i,1\}$, that is, of zone i and of the control zone NO1, and estimate:

$$P_{jt} = \alpha + \delta\, Treated_j + \varphi\, Post_t + \beta\left(Treated_j \times Post_t\right) + \gamma_1 P_t^{DK1} + \gamma_2 FR_{jt} + \theta\, Holiday_t + \lambda_h + \lambda_d + \lambda_m + \varepsilon_{jt} \qquad (6.1)$$

where P_{jt} is the price of zone j in hour t; $Treated_j$ equals 1 for the treated zone and 0 for NO1; $Post_t$ equals one from 13 April 2009 onwards; P_t^{DK1} is the daily Danish reference price assigned to each hour of the day; FR_{jt} is the reservoir fill ratio assigned to zone j; and $Holiday_t$ is a binary indicator for Norwegian public holidays. The terms λ_h, λ_d and λ_m are hour-of-day, day-of-week and month fixed effects, controlling for systematic temporal patterns in hourly electricity prices. The DK1 price and the fill ratios are standardised over the ±100-day window, before observations with missing values and the excluded days are removed. Because the two treated zones shared one price before the reform (Section 5), both panels use the same pre-reform treated series. Estimating (6.1) for NO2 and for NO3 gives the coefficients β_2 and β_3.[8]

Applying (6.1) to the price difference $s_t = P_{2t} - P_{3t}$, with a zero control series, gives a direct estimate of the mean post-reform difference between the two new zones conditional on the same covariates. Since s_t is zero by construction before the reform, this estimate corresponds to $E[s]$ in equation (4.4), and equals $\beta_2 - \beta_3$ up to the effect of the covariates.

Standard errors are clustered at the calendar-day level, which allows for correlation among the hourly residuals of the same day. As robustness we report standard errors clustered by calendar week and, for the reference specification, 95% percentile intervals from a block bootstrap over non-overlapping seven-day blocks (Appendix B).

6.3. Spread and attribution of the price effect

The attributable component of each DiD coefficient is estimated from the observed prices of the two new zones. The sample consists of the post-reform hours from 13 April to 22 July 2009, after the exclusions of Section 5, in which both zonal prices are positive and zonal consumption and generation are available. In each hour we compute the spread $s_t = P_{2t} - P_{3t}$, its positive and negative parts $s_t^+ = \max(s_t, 0)$ and $s_t^- = \max(-s_t, 0)$. and the slope K_{it} of net demand of each zone, given by equation (4.5) with the observed zonal generation, consumption and price of the hour. The weight w_t of equation (4.7) and the price effects a_{2t} and a_{3t} then follow hour by hour. The estimates of $E[a_2]$ and $E[a_3]$ are the sample means of these hourly quantities, and the bounds of equation (4.8) are computed from the sample means of s_t^+ and s_t^-.

For each specification the common component is then computed as

$$\hat{c}_i = \hat{\beta}_i - \hat{E}[a_i], \qquad i = 2,3 \qquad (6.2)$$

and we report the share $\hat{E}[a_2]/\hat{\beta}_2$ together with its upper bound $\hat{E}[s^+]/\hat{\beta}_2$, which does not depend on the elasticities.

[8] Aggregate generation, consumption and inter-regional flows are not included as controls because they are endogenous to price formation.

The central values of the elasticities are $\varepsilon_s = 0.67$ for supply and $|\varepsilon_d| = 0.020$ for demand, and the sensitivity analysis uses the grid $\varepsilon_s \in \{0.23, 0.67, 2.17\}$ and $|\varepsilon_d| \in \{0.005, 0.02, 0.05\}$; their sources are given in Section 8.1. Because w_t depends only on the ratio $K_{3t}/(K_{2t} + K_{3t})$, the estimates of a_i are much less sensitive to the level of the elasticities than the welfare gain, which depends on K_{eff}. Hours with non-positive prices or missing quantities are dropped as K_{it} is defined per unit of price. The 95% intervals are percentile intervals from 2,000 bootstrap draws over days (Appendix B).

6.4. Identification and robustness

The DiD design requires the reform date to be exogenous to short-term swings in the price differential between the treated zones and NO1, and the absence of systematic pre-reform trends between them. NO1 is moreover interconnected with the treated zones and could be affected by the reform through redirected flows; such an effect would enter the common component c in (4.3) and affect how β_i is interpreted, but not the estimates of a_2 and a_3, which rest on the spread between the two new zones and not on NO1. These conditions are assessed with an event study, a linear pre-trend test and placebo reforms, defined in Appendix A and reported in Section 7.4. The robustness of the results to the control variables, the estimation window, the treatment of the episode of 21–30 July, the removal of individual weeks and the method of inference is summarised in Sections 7.4 and 7.5.

7. Results: the reform of 13 April 2009

The results follow the sequence set out in Section 6.1. The allocative gain and the transfers are discussed in Section 8. Unless stated otherwise, the sample is the main sample of Section 5 (4,775 hourly observations per zone, 9,550 per stacked panel) and standard errors are clustered by calendar day.

7.1. Price changes relative to NO1

Table 2 reports the DiD coefficients of equation (6.1) for the reference specification and the range across the five specifications described and reported in full in Appendix B.

Table 2.
Difference-in-differences estimates of the post-reform price change relative to NO1 (€/MWh)

Specification	NO2: $\widehat{\beta}_2$	NO3: $\widehat{\beta}_3$	NO2 – NO3: $\widehat{\beta}_2 - \widehat{\beta}_3$
Reference: reservoirs Centre vs South	0.898 (0.206) [0.277]	0.727 (0.203) [0.299]	0.171 (0.059) [0.096]
95% block-bootstrap interval	[0.319, 1.400]	[0.111, 1.265]	[0.007, 0.378]
Range across the five specifications	0.658 – 0.905	0.531 – 0.727	0.127 – 0.179

Note: Coefficients of Treated × Post in equation (6.1) for NO2 and NO3, each against NO1 as control, and of the post-reform shift of the spread $s_t = P_{2t} - P_{3t}$ against a zero control series (last column). Standard errors clustered by calendar day in parentheses and by calendar week in brackets. The block-bootstrap interval is the 95% percentile interval of 300 resamples of non-overlapping seven-day blocks of days. Sample: main sample of Section 5 (4,775 hourly observations per zone). The five specifications are described and reported in Appendix B.

Both new zones became more expensive relative to NO1 after the reform. In the reference specification the price of NO2 rose by €0.898/MWh (standard error 0.206 with day clusters and 0.277 with week clusters) and the price of NO3 by €0.727/MWh (0.203 and 0.299). Across the five specifications $\hat{\beta}_2$ ranges between 0.658 and 0.905 and $\hat{\beta}_3$ between 0.531 and 0.727. These magnitudes are of the same order as the raw changes in the price gap with respect to NO1 in Table 1 (+€1.061/MWh for NO2 and +€0.878/MWh for NO3), which are larger because they do not condition on the DK1 price, the reservoirs and the calendar effects.

The two coefficients are close to each other, and they move together across specifications, so their difference, estimated directly on the spread (Section 6.2), is almost unchanged: €0.171/MWh in the reference specification and between 0.127 and €0.179/MWh in the others, about one fifth of $\hat{\beta}_2$. It is significant at the 1% level with day clusters (t = 2.9), at 10% with week clusters (t = 1.8), and the bootstrap interval, [0.007, 0.378], only just excludes zero. We therefore read the difference as positive but imprecisely estimated: allowing for serial correlation at the weekly horizon, it is significant only at the 10% level.

The DiD coefficients describe how far each new zone moved away from NO1. Section 7.2 asks how much of that movement can be attributed to the split.

7.2. What part of the price change is attributable to the split

Table 3 reports the spread and the attribution of Section 6.3 for the reference sample.

Table 3.
Spread and price effects of the split (€/MWh, reference sample)

Quantity	Estimate	95% interval
Mean spread $E[s]$	0.183	[0.072, 0.318]
Price effect on NO2, $E[a_2]$	0.118	[0.048, 0.203]
Price effect on NO3, $E[a_3]$	−0.065	[−0.117, −0.023]
Upper bound, $E[s^+]$	0.223	[0.119, 0.354]
Lower bound, $-E[s^-]$	−0.040	[−0.064, −0.017]

Note: Hourly sample of 2,376 hours (99 days) with both zonal prices positive and quantities available; $\varepsilon_s = 0.67$, $\lvert\varepsilon_d\rvert = 0.02$; the mean weight of NO2 is 0.542. $E[a_2]$ is bounded by $-E[s^-]$ and $E[s^+]$, and $E[a_3]$ by $-E[s^+]$ and $E[s^-]$ (equation 4.8). Intervals are 95% percentile intervals from 2,000 bootstrap draws over days.

The mean spread between the two new zones is €0.183/MWh (interval 0.072 to 0.318), in line with the direct estimate of $\hat{\beta}_2 - \hat{\beta}_3$ in Table 2. Under assumptions A1–A3, the clearing condition of Section 4.2.2 assigns it to the two zones: the split raises the price of NO2 by €0.118/MWh and lowers that of NO3 by €0.065/MWh.[9] Both estimates lie inside the bounds

[9] The estimate $\hat{E}[a_2] = 0.118$ is the mean of the hourly products $w_t\, s_t$ and not the product of the mean weight (0.542) and the mean spread (0.183), which would be 0.099: the weight of NO2 is larger in hours with larger spreads.

of equation (4.8), which require $E[a_2]$ to lie between −0.040 and 0.223 and $E[a_3]$ between −0.223 and 0.040. Over the nine combinations of the grid of Section 6.3, $\hat{E}[a_2]$ lies between 0.113 and 0.118.

The part attributable to the split is $E[a_2] = €0.118/MWh$, which is 13% of $\hat{\beta}_2$ in the reference specification and between 13% and 18% across the five specifications (Appendix B). This share is lower than the ratio of the spread to $\hat{\beta}_2$ (about one fifth) because only part of the spread falls on NO2; the rest lowers the price of NO3 ($E[a_3]$ = −0.065). Even the upper bound $E[s^+]$, which does not depend on the elasticities, accounts for between 25% and 34% of $\hat{\beta}_2$. The remainder, the common component $\hat{c}$, is between 0.54 and €0.79/MWh and is not attributable to the split by the method of Section 4.2.2.

Two pieces of evidence suggest that the common component does not come from the price difference between the two zones. First, it moves with the estimation window while the spread does not: in the reference specification $\hat{\beta}_2$ is €1.170/MWh with a ±60-day window, 1.101 with ±80 days, 0.898 with ±100 days and 3.252 when the sample is extended to 10 January 2010, whereas $\hat{\beta}_2 - \hat{\beta}_3$ stays between 0.120 and 0.239 (Appendix C). Second, relative to the DK1 price, the price of NO1 shows no significant change after the reform (€0.238/MWh, p = 0.70), while the coefficients of NO2 (1.073, p = 0.061) and NO3 (0.831, p = 0.145) are larger but only marginally significant or not significant: the common movement appears specific to the area of the former NO2, although this diagnostic is only suggestive (Appendix A).

We do not attribute the common component to a specific cause. It may reflect hydrological or demand conditions not captured by the reservoir ratios, or an effect of the reform on the common price level that operates through a channel other than the NO2–NO3 spread, which would violate assumption A2 of Section 4.2.2. The data do not separate these explanations. The appropriate reading is therefore not that the reform did not raise the price of the former NO2 area, but that the DiD coefficient does not identify such an effect, whereas the spread identifies the part of the change in relative prices that is due to the split.

7.3. The price spread and the flows on the new interface

Prices of the two zones were equal in 87.5% of the post-reform hours (Tables D1 and D2). The spread $s_t = P_{2t} - P_{3t}$ was positive (NO2 more expensive) in 7.2% of the hours, with a mean of €3.1/MWh, and negative in 5.4%, with a mean absolute value of €0.7/MWh. The spread is therefore an episodic phenomenon: it is concentrated in a few days, in particular 21–23 April and 17–21 June, rather than spread evenly over the window (see Table C5 for the days with the largest gains; Tables D1 and D2 give the distribution by month and overall).

Flows between NO2 and NO3 are almost entirely one-directional: NO2 imports from NO3 in 90.3% of the hours and never exports to NO3, with a mean net flow of 268 MW. The capacity from NO3 to NO2 averages 657 MW and is never zero, whereas the capacity from NO2 to NO3 is zero in every hour of the sample. Price separation can therefore arise on this interface only when the flow towards NO2 reaches its limit (positive spread) or when NO3 is scarce and cannot be relieved from NO2 (negative spread). The other interface of the new NO2, with NO1, is bidirectional (Table D3).

7.4. Identification checks

In the event study (Figure A1, Appendix A) the pre-reform coefficients of both zones fluctuate between $-€0.64$ and $+€0.62$/MWh, none of them individually larger than twice its

standard error. In the first two post-reform blocks (13 April to 10 May) they are 2.30 and 1.69 for NO2 and 2.06 and 1.75 for NO3; from 11 May onward they lie between -0.73 and $+0.73$ and none is significant. The two zones follow almost the same path, so the adjustment captured by the DiD coefficient is concentrated in the first four weeks after the reform and shared by both. A common jump that starts at the reform date is what an effect of the reform on the common price level would look like, but it is also compatible with other changes that began at the same time.

The support for parallel trends is only partial. The joint test of the seven pre-reform block coefficients rejects with day clusters in three of the four specifications ($p = 0.043$ in the reference one), and, with week clusters, in the same three (p ≤ 0.001, against 0.595 in the specification with current area names); with about 30 weekly clusters and seven restrictions, however, the weekly test tends to over-reject, so the rejection with day clusters is the more informative. The linear pre-trend is not significant in the reference specification ($p = 0.151$) with day clusters in two of the other three ($p = 0.006$ and $p = 0.045$), with opposite signs (+€0.428 and −€0.635/MWh per 30 days), and none is significant at the 5% level with week clusters; and all fifteen placebo reforms give positive estimates (€0.08 to €0.71/MWh); two of them, both for the placebo at −60 days (reference and former-NO2 specifications), are significant at the 5% level with day clusters, and with week clusters only one is (p = 0.049). A linear continuation of the pre-reform differential trend would shift $\hat{\beta}_2$ by between −€2.1 and +€1.4/MWh across specifications, and in the former-NO2 specification by more than the whole coefficient (Appendix A). The pre-reform trends are too unstable to be used as a correction, and the individual DiD coefficients are best read as descriptive.

These tests do not apply to the difference between the two zones, which is zero by construction before the reform: any pre-trend common to the two zones cancels in the difference. The difference is positive in all the estimation windows (€0.120 to €0.239/MWh), including the ±60- and ±80-day windows, which contain no excluded days, and in all 30 leave-one-week-out estimates (0.099 to 0.205), although it depends in part on a few episodes of price differences in June (Appendix C).

7.5. Treatment of 22 July and of the episode of 21–30 July

The result on the spread depends on how 22 July 2009 is treated. On that day the NO2 price averaged €17.3/MWh and the NO3 price €34.4/MWh, the prices differed in all 24 hours and the mean spread was $-€17.1$/MWh. The day belongs to an episode of ten calendar days (21–30 July), identified by the rule of Section 5, whose mean spread ($-€2.8$/MWh) is the only negative one among the nine episodes found with this rule in the extended sample; in the main window it comprises the last two days, 21 and 22 July. Table 4 compares the main sample with the sample with no exclusion.

Table 4.
Results with and without the episode of 21–30 July

	Episode excluded (main)	No exclusion
Observations per zone	4,775	4,823
Mean spread $E[s]$	0.183 [0.072, 0.318]	−0.002 [−0.408, 0.269]
$\hat{E}[a_2]$	0.118 [0.048, 0.203]	0.069 [−0.048, 0.176]
$\hat{E}[a_3]$	−0.065 [−0.117, −0.023]	0.071 [−0.095, 0.355]

Note: Reference specification. Standard errors clustered by day in parentheses; 95% intervals in brackets (day bootstrap, 2,000 draws). The allocative gain in the two samples is reported in Section 8.1.

With no exclusion the mean spread is zero (*−€0.002*/MWh, interval *−0.408* to *0.269*), the difference $\hat{\beta}_2 - \hat{\beta}_3$ is *−0.033* and the sign of the price effect on NO3 reverses. In the sample extended to 10 January 2010 the difference falls from 0.129 (standard error 0.030) to 0.021 (0.071). Without the exclusion the effect of the split on relative prices is therefore not identified. Excluding only 22 July gives nearly the same results as excluding the whole episode: $\hat{\beta}_2 - \hat{\beta}_3$ is 0.156 (0.060) and the mean spread 0.169.

As explained in Section 5, the episode is excluded from the estimation of the price effect for two reasons. Firstly, 22 July stands out from the other days in terms of both magnitude and sign: no other day amongst the fifteen with the highest allocative gain has an average spread exceeding €3.9/MWh in absolute terms, and it is the only one of the nine episodes in which NO3 is the more expensive; this situation cannot be resolved by NO2, as the capacity from NO2 to NO3 is zero in every hour[10]. Secondly, the positive difference does not depend on the exclusion; indeed, it is present in the ±60 and ±80-day windows, which do not include it (Appendix C). The episode is not ignored in the welfare analysis: it is valued separately from observed prices and added once to the annual gain (Section 8.1). Since the spread has the opposite sign on that day, the transfers it generates also have the opposite sign to those on other days (Section 8.2).

The exclusion was chosen after seeing that the day is influential, and it removes a day with a negative spread, so Appendix C also reports what happens when other episodes are removed: excluding all the episodes that fall inside the window lowers $\hat{\beta}_2 - \hat{\beta}_3$ to 0.029 (0.027). This measures how concentrated the spread is in a small number of days, since episodes are defined by large spreads, and not the fragility of the estimate: the positive spread is generated by episodes of large price differences and not by a uniform shift of the price of NO2 above that of NO3.

8. Welfare effects of the split

This section translates the price effects of Section 7.2 into an allocative gain and into transfers between consumers and producers. Following Hogan (1992), applying a single price to a geographically heterogeneous area can lead to allocative inefficiency, and the gain from splitting it arises because supply and demand can adjust once prices reflect local scarcity. The calculations use the hourly spread between NO2 and NO3 and the clearing condition of

[10] Independent explanations are not provided as the market messages of that period are not publicly available by Statnett.

Section 4.2.2, not the DiD coefficients, which are dominated by a component that cannot be attributed to the split. We read the spread as a difference in local scarcity (Section 7.3) and maintain assumption A1 of Section 4.2.2; we do not test for changes in market power.

8.1. Allocative gain

The allocative gain is computed hour by hour from equation (4.9), using the slopes K_{it} of equation (4.5), which scale the supply response by the observed generation of each zone and the demand response by its observed consumption; with K_{it} measured in MWh per €/MWh the gain is expressed in euros and totals are sums over hours. The calculation covers the 2,376 post-reform hours of the main sample (99 days) in which both zonal prices are positive and zonal quantities are available. It is the Harberger-type triangle of the price difference between the two zones (Harberger, 1954), summed over hours.

We do not impose a single elasticity. The supply elasticities of 0.23, 0.67 and 2.17 are taken from Birkedal and Bolkesjø (2016) and reflect seasonal differences in the responsiveness of Norwegian hydropower (spring, annual average and winter, respectively). The demand elasticities of 0.005, 0.020 and 0.050 reflect the low short-run responsiveness of electricity consumption (Bye and Hansen, 2008; Lee and Chiu, 2011; Holstad and Pettersen, 2011). The central values are $\varepsilon_s = 0.67$ and $|\varepsilon_d| = 0.020$.

Under the central values the allocative gain is €24,335 over the observed period (95% interval [10,830, 42,515]). For annual figures we use the sample extended to 10 January 2010 (three-zone configuration), which has 263 days outside the episode of 21-30 July and 273 days with it. The 263 days yield €55,334 [30,248, 85,109], or €210 per day. The episode, which cannot be used in the DiD estimates but can be valued from observed prices, adds €90,442 [4,930, 257,579] over its ten days, 93% of which arises on 22 July. The annual value under assumption (ii) values the 355 days of the year outside the episode at the average daily gain of the 263 days and adds the episode once: it is €165,132 [53,962, 337,719]. Under assumption (i) the remainder of the year yields no gain and the annual value is the extended sample as observed, including the episode: €145,776 [41,473, 316,570]. Both assume that an episode like the one in July occurs once a year, which the data cannot test, since no other day in the 273 has a spread of comparable size.

Table 5 reports the gain for each supply elasticity at the central demand elasticity. The result is driven almost entirely by the supply side: raising the demand elasticity from 0.005 to 0.05 changes the gain by 8%, whereas the supply elasticity moves it by a factor of nine; at the central values the demand-side term is about €860, or 3.5% of the total, so that the supply term is about 27 times larger. Because the observed window consists mainly of spring and early summer, to which the lowest supply elasticity applies, we report all three values: the annual value under (ii) ranges between about €56,000 and €531,000. The treatment of the episode of 21–30 July is discussed in Section 7.5, and the sensitivity of the annual values to it and to the calculation of the slopes is reported in Tables E1 and E4.

Table 5.
Allocative gain: sensitivity to supply and demand elasticities (€)

	$\lvert\varepsilon_d\rvert = 0.005$	$\lvert\varepsilon_d\rvert = 0.020$	$\lvert\varepsilon_d\rvert = 0.050$
Panel A: observed period (99 days)			
$\varepsilon_s = 0.23$ (spring)	8,274	8,915	10,184
$\varepsilon_s = 0.67$ (annual average)	23,691	24,335	25,619
$\varepsilon_s = 2.17$ (winter)	76,248	76,894	78,183
Panel B: annual value (ii), extended sample			
$\varepsilon_s = 0.23$ (spring)	56,209	60,044	67,670
$\varepsilon_s = 0.67$ (annual average)	161,288	165,132	172,803
$\varepsilon_s = 2.17$ (winter)	519,509	523,357	531,046

Note: Allocative gain from equation (4.9), reference sample with the episode of 21–30 July excluded. Panel B values the 355 days of the year outside the episode at the average daily gain of the 263 days of the extended sample (13 April 2009 – 10 January 2010) and adds the episode once, as observed; it is the annual value (ii) of Section 8.1. Annual values are indicative orders of magnitude.

The gain is concentrated in a few hours because it is quadratic in the spread: the ten hours with the largest gain account for 42% of the total and the 24 largest for 65%. In the annual value the concentration is greater: the episode accounts for 55% of the gain under assumption (ii) and 22 July alone for 51%. The other sensitivities, including the calculation of K_{it} and the distribution by month, are in Appendix E.

The figures are the allocative gain. As noted in Section 4.2.4, the same area, $1/2\, s_t \Delta F_t$ in equation (4.9), can be read as the cost of the counter-trading that the split makes unnecessary, to the extent that it reflects supply-side adjustment; the two readings are not additive, so we do not add the avoided counter-trading cost to the allocative gain. The counter-trading and capacity-reduction cost C^{CT} on the interface before the reform is not observed for 2009, so the model-implied value, $1/2 \sum_t s_t\, \Delta F_t$ over the hours with a binding constraint, cannot be compared with the observed one.

8.2. Redistribution of surplus

Beyond its efficiency effect (Section 8.1), the price effect of the split redistributes surplus between consumers and producers. To first order, the changes in consumer and producer surplus in zone i are:

$$\Delta CS_i = -\sum_t a_{it}\, D_{it}, \qquad \Delta PS_i = +\sum_t a_{it}\, S_{it} \tag{8.1}$$

where $a_{2t} = w_t s_t$ and $a_{3t} = -(1 - w_t) s_t$ are the hourly price effects of equation (4.7) and D_{it} and S_{it} are the observed consumption and generation of zone i in hour t, in the same hours as the allocative gain. Table 6 reports the results.

Table 6.
Transfers between consumers and producers (€)

	Observed period (99 days)	95% interval	Annual value (ii)	95% interval	Of which episode
Consumers, NO2	−515,367	[−886,549, −223,455]	−1,073,900	[−1,816,199, −431,697]	+375,238
Producers, NO2	+337,518	[127,843, 601,782]	+775,056	[247,357, 1,373,018]	−349,627
Consumers, NO3	+227,547	[90,540, 394,392]	+142,515	[−687,921, 758,815]	−557,228
Producers, NO3	−273,467	[−484,895, −93,668]	−309,926	[−1,021,263, 557,158]	+614,170
Net, consumers (NO2 + NO3)	−287,820		−931,386	[−1,491,713, −476,171]	−181,990
Net, producers (NO2 + NO3)	+64,051		+465,129	[144,767, 964,791]	+264,543

Note: First-order changes from equation (8.1), reference sample, central elasticities. Intervals are 95% percentile intervals from 2,000 bootstrap draws over days. Annual value (ii) values the 355 days of the year outside the episode of 21–30 July at the average daily value of the 263 days of the extended sample and adds the episode once, as observed; the last column reports the episode.

Over the 99 days, in the two zones together, consumers face a net transfer of approximately €288,000, whilst producers receive a net gain of €64,000. The effects on price amount to 0.3% of the price in NO2 and 0.2% of that in NO3; therefore, most of the effect of the subdivision consists of a transfer. In the absence of the exclusion, none of the transfers during the period under review can be distinguished from zero, and those in NO3 reverse sign (Table E2).

The annual figures shown in Table 6 assess the episode of 21–30 July separately, as in Section 8.1. During the episode, the spread is negative in 62% of the hours and never positive (average −2.81 €/MWh): zone NO2 is cheaper than NO3 and the transfers have the opposite sign, whilst in zone NO3 the signs are reversed: NO2 consumers gain and NO2 producers lose, while NO3 consumers lose and NO3 producers gain. The sign of the transfer follows the sign of the spread, while the allocative gain depends on its square; therefore, the annual transfers offset two opposing regimes.

Since the gain does not depend on the sign of the spread, the transfers should be compared with it without taking the sign into account. Table 7 shows them in absolute terms, hour by hour. On normal days, consumer transfers in NO2 are around 25 times the allocative gain and those of producers around 20 times; during the episode, the ratios fall to around 4 in NO2 and between 6 and 7 in NO3. The annual net transfer from consumers in NO2 is 6.5 times the gain, approximately half the transfer in absolute terms (13 times), as part of it cancels itself out over the course of the year: on any given day, the redistribution is substantial compared with the gain, but over the course of the year it is smaller. The absolute measure counts the hourly redistributions without netting and is therefore an upper bound on the reallocation between groups, while the net transfer is a lower bound; the two bracket the comparison with the gain.

Table 7.
Transfers in absolute value and ratio to the allocative gain

	Annual value (ii) (€)	Observed period	Normal days	Episode	Annual value (ii) [95% interval]
Consumers, NO2	2,216,997	28.5	24.7	4.1	13.4 [7.2, 31.5]
Producers, NO2	1,852,539	20.8	20.1	3.9	11.2 [6.0, 26.4]
Consumers, NO3	1,547,412	14.4	13.3	6.2	9.4 [6.6, 18.9]
Producers, NO3	1,932,329	18.4	17.6	6.8	11.7 [7.8, 24.8]

Note: Transfers are the sum over hours of the absolute price effect times consumption (consumers) or generation (producers), compared with the allocative gain over the same days: observed period, 99 days, 24,335 €; normal days, 263 days, 55,334 €; episode, 10 days, 90,442 €; annual value (ii), 165,132 €. The interval is the 95% percentile interval from 2,000 bootstrap draws over days.

The sum of the net transfers, −224,000 € over the period, equals minus the congestion rent only when the two zones trade solely with each other (Section 4.2.4). Both trade with Sweden and NO2 also with NO1, so we do not interpret the sum as a measure of the rent, which is based on observed flows. Changes in grid tariffs, which may follow from congestion rents and counter-trading costs, are not included in these transfers (Section 8.3). The sum of the net transfers, in the period and in the year, is reported in Table E2.

8.3. Costs and benefits of bidding zone reconfiguration

The allocative gain is modest. The annual value under assumption (ii) is €165,000 at the annual-average supply elasticity (€146,000 under assumption (i)) and between €56,000 and €531,000 across the three supply elasticities, which corresponds to about €0.0047/MWh relative to consumption in NO2 and NO3 (about 34.8 TWh in 2009), or about 0.01% of the pre-reform price of €37.86/MWh, and to between €0.0016/MWh and €0.0153/MWh (0.004% to 0.04%). Relative to the consumption of the three zones in 2009 (119.5 TWh) the gain is about €0.0014/MWh, or about 0.004% of the pre-reform price. About half of it arises on a single day, so the figure rests on the assumption that a day like 22 July occurs once a year. Even a slight decline in trading efficiency following the split would offset this gain, so the estimate should be viewed within a broader assessment of the costs and benefits of a new BZ.

FTI Consulting (2025), in a study for Great Britain commissioned by Octopus Energy, identifies three potential benefits of a zonal system: more efficient dispatch, better location decisions and a reduced need for transmission investment. Our estimate relates to a part of the first: it measures the allocative gain from the response of supply and demand to a more accurate price, not the reduction in redispatch costs, which in FTI's assessment is the main component (£40.2 billion in present value over 2030–2050) and cannot be added to our gain (Section 8.1). FTI's total welfare gain, £1.7 billion per year, is four orders of magnitude larger than ours, but the two are not comparable: FTI assesses 12 zones over twenty years in a system with a large expansion of renewables, and its consumer benefit (£54.9 billion, against a welfare gain of £25.2 billion) depends on congestion rents being passed on to consumers. As in the Norwegian case, the distributional effects of zonal pricing are much larger than its effect on total welfare: Green (2007) finds for England and Wales that moving to optimal nodal prices raises welfare by 1.3% of generators' revenues, while creating regional gains and politically sensitive losses. On the cost side, greater granularity may reduce liquidity, make hedging in forward markets more expensive, strengthen local market power and entail implementation costs. FTI estimates the latter at two orders of magnitude below the benefits, and, citing limited evidence of an increase in the cost of capital, assumes no effect on it; Blyth

et al. (2025), by contrast, estimate that zonal pricing could raise strike prices in forthcoming CfD auctions by up to £20/MWh, because investors would price the volume risk arising from transmission constraints.

The assessment of a new zone also depends on how congestion rent is used. In Norway the rent accrues to Statnett and is returned to grid customers through network tariffs; only under a temporary scheme introduced in October 2022 and extended to the end of 2025 has it been directed to customers in the zones facing the highest prices (Ministry of Energy, 2024). Whether splitting a zone is worthwhile therefore depends on dynamic effects, the costs of market fragmentation and the use of congestion rent.

9. Conclusions

Through an analysis of the 2009 Norwegian reform, we show how it is possible to measure, on the basis of observed prices, the effect on welfare resulting from the subdivision of a market into several zones. The direct allocative gain is positive, though modest. The main effect, however, is distributional: the transfers between consumers and producers are much larger than the gain and change sign between normal days and the rare days characterised by large price differences, so that the net transfers over the course of the year are smaller than the absolute transfers. On days such as 22 July 2009, a single price would have hidden congestion in the opposite direction. This result suggests that, in integrated systems, separate prices are not needed on most days but prove valuable during episodes of local scarcity. The analysis is static and does not consider dynamic effects or the costs of market fragmentation.

The results come with some caveats. Firstly, the pre-reform tests support the hypothesis of parallel trends only in part (Appendix A). Secondly, the time window of ±100 days captures the short-term response to the reform, while the annual data are indicative (Section 8). They depend on the assumed elasticities and on an episode like 21–30 July occurring once a year, which the data cannot verify, as no other day in the sample shows a comparable deviation. Valuing the episode more or fewer times than once a year would change both the annual figure and its composition. The main estimates exclude the episode from the estimation and value it separately; if it is included, the average price difference is no longer statistically significant, and the transfers cannot be distinguished from zero (Appendix C). The magnitude of the episode also depends on demand and supply slopes at low prices, which are not observable (Table E4). Finally, the analysis does not consider counter-trading and capacity-reduction costs, nor how the domestic constraint was handled before the reform, for which we have no specific data. Moreover, NO3 had already existed until November 2008, so participants may have anticipated its reinstatement, which would, if anything, tend to reduce the estimated price effect. Extending the analysis to the November 2008 merger and other bidding-zone reforms, with more detailed bidding data, could show whether the static gain found here is representative.

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Appendix A. Identification tests

This appendix defines the identification tests of Section 6.4 and reports their results. The event study replaces the coefficient of equation (6.1) with coefficients by 14-day block relative to the reform date:

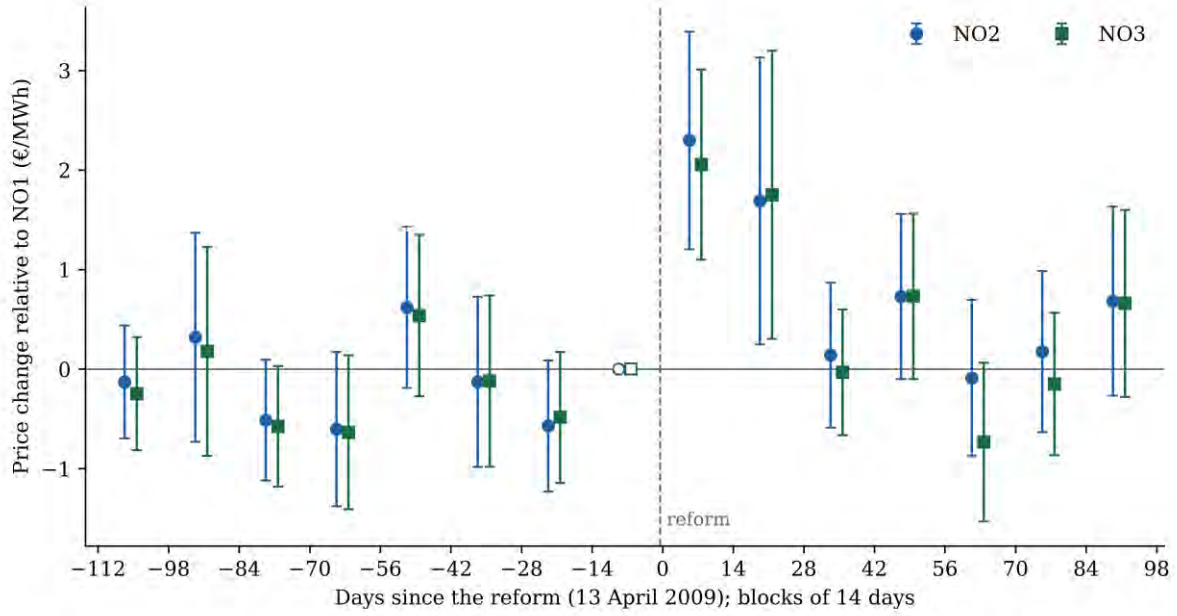
$$P_{jt} = \alpha + \delta\, Treated_j + \sum_{k\neq -1} \varphi_k\ 1[B_t = k] + \sum_{k\neq -1} \beta_k \left(Treated_j \times 1[B_t = k]\right) + \gamma_1 P_t^{DK1} + \gamma_2 FR_{jt} + \theta\, Holiday_t + \lambda_h + \lambda_d + u_{jt} \quad \text{(A.1)}$$

where $B_t = \lfloor(\text{day of } t - 13 \text{ April } 2009)/14\rfloor$ indexes the block and the block $k = -1$, which covers the 14 days before the reform, is the reference. Month effects are omitted because the blocks absorb them. The linear pre-trend test is run on pre-reform data for NO2 against NO1:

$$P_{jt} = \alpha + \delta\, Treated_j + \phi\, \tau_t + \psi \left(Treated_j \times \tau_t\right) + \gamma_1 P_t^{DK1} + \gamma_2 FR_{jt} + \theta\, Holiday_t + \lambda_h + \lambda_d + u_{jt} \quad \text{(A.2)}$$

where τ_t is time in units of 30 days from the start of the window and the null hypothesis is $\psi = 0$. The joint Wald test is that the seven pre-reform block coefficients of (A.1) other than the reference are zero; with about 30 weekly clusters its finite-sample reliability is limited. The placebo reforms estimate equation (6.1) for NO2 on pre-reform data only, with $Post_t$ replaced by an indicator for the dates from k days after the actual reform date, $k \in \{-70, -60, -50, -40, -30\}$. The event study and the pre-trend tests are run for the reference specification, the former-NO2 and current-area alternatives and a specification without reservoir control; the placebo analysis for the first three.

Figure A1.
Event study: price of NO2 and NO3 relative to NO1 by 14-day block (€/MWh)



Note: Coefficients β_k of equation (A.1) with 95% confidence intervals based on standard errors clustered by day. The reference block is 30 March – 12 April 2009. The last post-reform block is not shown because it contains only one day (20 July) after the exclusion of 21 and 22 July.

Table A1.
Pre-reform tests, NO2 against NO1

Specification	Joint Wald test: p (day)	Joint Wald test: p (week)	Trend $\hat{\psi}$ (€/MWh per 30 days)	p (day)	p (week)
Reference	0.043	0.000	−0.286	0.151	0.468
Former NO2 reservoirs	0.003	0.001	0.428	0.006	0.085
Current area names	0.489	0.595	−0.635	0.045	0.251
No reservoir control	0.002	0.000	0.188	0.109	0.059

Note: The Wald test has seven restrictions (the pre-reform block coefficients of equation (A.1)). The linear test is the coefficient ψ of equation (A.2), estimated on the pre-reform window. Standard errors clustered by day and by week.

If the differential trend of Table A1 continued unchanged after the reform, the DiD coefficient would contain a component equal to the trend multiplied by the distance between the mean dates of the post- and pre-reform windows, about 3.3 units of 30 days: −0.95 €/MWh in the reference specification, +1.42 in the former-NO2 specification, −2.11 with current area names and +0.62 without reservoir control. In the former-NO2 specification this exceeds $\hat{\beta}_2$ (0.743). We do not use these figures as corrections, because the sign of the trend is not stable across specifications and the trends are estimated with limited precision.

Table A2.
Placebo reforms, NO2 against NO1: coefficient (p-value with day clusters / with week clusters)

Placebo date (days before reform)	Reference	Former NO2 reservoirs	Current area names
−70	0.325 (0.219 / 0.277)	0.331 (0.213 / 0.283)	0.322 (0.238 / 0.280)
−60	0.647 (0.010 / 0.069)	0.708 (0.005 / 0.049)	0.471 (0.063 / 0.134)
−50	0.242 (0.334 / 0.529)	0.277 (0.280 / 0.499)	0.080 (0.747 / 0.815)
−40	0.311 (0.188 / 0.264)	0.300 (0.201 / 0.275)	0.307 (0.210 / 0.299)
−30	0.192 (0.368 / 0.438)	0.163 (0.439 / 0.485)	0.215 (0.350 / 0.481)

Note: Coefficient of Treated × Post of equation (6.1) with the pseudo-reform at the indicated date, on pre-reform data. In the pre-reform window NO3 coincides with NO2, so the placebo applies equally to NO3.

Congestion in southern Norway is not always exogenous to producer behaviour (Mirza and Bergland, 2015) and in 2008 it was itself a source of price differences between NO1 and the rest of Norway, owing to bottlenecks out of southern Norway towards Sweden and Denmark (Sandsmark, 2009). To the extent that such events move the NO1 price independently of the reform, they add variation to the control series that the fixed effects and the hydrological controls only partly absorb. Table A3 reports a daily diagnostic in which the price of each zone is compared with the Danish reference price: NO1 shows no significant change after the reform (0.238, $p = 0.70$), whereas NO2 and NO3 rise by 1.073 ($p = 0.061$) and 0.831 ($p = 0.145$), the latter not significant.

Table A3.
Daily difference-in-differences of each zone against the Danish reference price (€/MWh)

Zone	Coefficient	Std. error	p-value	Days
NO1	0.238	0.613	0.698	199
NO2	1.073	0.573	0.061	199
NO3	0.831	0.570	0.145	199

Note: Coefficient of Treated × Post for the daily mean price of the zone against the daily price of DK1 as control, with the reservoir fill ratio of the zone's area, a holiday indicator and day-of-week and month effects. Standard errors clustered by day. The diagnostic does not estimate the effect of the reform: it shows which zones moved relative to the common Nordic price and is used to interpret the common component of Section 7.2.

Appendix B. Specifications and inference

The five specifications differ in the reservoir fill ratio assigned to the treated zone and to NO1 and in the import-capacity control. In the reference specification the treated zone is assigned the fill ratio of Central Norway (current price area NO3) in both panels and NO1 that of Southern Norway (current areas NO1, NO2 and NO5 together). The first alternative assigns to the treated zone the fill ratio of the former NO2 (current areas NO3 and NO4 together); the second uses the fill ratios of the current areas NO2 and NO1, which do not correspond to the 2009 zones and are reported for comparability; two further variants add the standardised hourly import capacity of the treated area and of NO1 to the reference and former-NO2 specifications. Standard errors are clustered by calendar day; the alternatives are clusters by calendar week (seven-day blocks aligned to the reform date, about 30 clusters in the main sample, the first and last being partial) and, for the reference specification, 95% percentile intervals from a block bootstrap that resamples non-overlapping seven-day blocks of days

with replacement (300 resamples). The intervals of the attribution estimates are percentile intervals from 2,000 bootstrap draws over days; the random seed is fixed in the replication code.

Table B1.
Difference-in-differences estimates of the post-reform price change relative to NO1, all specifications (€/MWh)

Specification	NO2: $\hat{\beta}_2$	NO3: $\hat{\beta}_3$	NO2 − NO3: $\hat{\beta}_2 - \hat{\beta}_3$
Reference: reservoirs Centre vs South	0.898 (0.206) [0.277]	0.727 (0.203) [0.299]	0.171 (0.059) [0.096]
95% block-bootstrap interval	*[0.319, 1.400]*	*[0.111, 1.265]*	*[0.007, 0.378]*
Reservoirs of the former NO2 (Centre and North) vs South	0.743 (0.230) [0.352]	0.600 (0.223) [0.347]	0.143 (0.051) [0.084]
Reservoirs by current area names (NO2 vs NO1)	0.905 (0.222) [0.344]	0.726 (0.214) [0.346]	0.179 (0.062) [0.098]
Reference + import capacity	0.810 (0.197) [0.260]	0.655 (0.196) [0.289]	0.155 (0.052) [0.083]
Former NO2 + import capacity	0.658 (0.221) [0.338]	0.531 (0.215) [0.336]	0.127 (0.045) [0.072]

Note: Coefficients of Treated × Post in equation (6.1) for NO2 and NO3, each against NO1 as control, and of the post-reform shift of the spread $s_t = P_{2t} - P_{3t}$ against a zero control series (last column). Standard errors clustered by calendar day in parentheses and by calendar week in brackets. The block-bootstrap interval is the 95% percentile interval of 300 resamples of non-overlapping seven-day blocks of days. Sample: main sample of Section 5 (4,775 hourly observations per zone).

Table B2.
Components of the DiD coefficients by specification (€/MWh)

Specification	$\hat{\beta}_2$	$\hat{E}[a_2]$	$\hat{c}_2$	$\hat{E}[a_2]/\hat{\beta}_2$	$\hat{E}[s^+]/\hat{\beta}_2$	$\hat{\beta}_3$	$\hat{E}[a_3]$	$\hat{c}_3$
Reference	0.898	0.118	0.780	0.131	0.248	0.727	−0.065	0.792
Former NO2 reservoirs	0.743	0.118	0.625	0.158	0.300	0.600	−0.065	0.665
Current area names	0.905	0.118	0.788	0.130	0.246	0.726	−0.065	0.791
Reference + import capacity	0.810	0.118	0.693	0.145	0.275	0.655	−0.065	0.720
Former NO2 + import capacity	0.658	0.118	0.540	0.179	0.339	0.531	−0.065	0.596

Note: $\hat{c}_i = \hat{\beta}_i - \hat{E}[a_i]$ (equation 6.2). The price effects $\hat{E}[a_i]$ do not depend on the DiD specification because they are computed from the observed spread and the clearing condition.

Appendix C. Sample and window sensitivity

This appendix reports the sensitivity of the results to the estimation window, to individual weeks and to the treatment of the episode of 21–30 July 2009, defined in Section 5.

Table C1.
Reference specification by estimation window (€/MWh)

Window	Observations per zone	$\hat{\beta}_2$	$\hat{\beta}_3$	$\hat{\beta}_2 - \hat{\beta}_3$
±60 days	2,903	1.170 (0.279) [0.363]	1.050 (0.268) [0.356]	0.120 (0.048) [0.058]

Window	Observations per zone	$\hat{\beta}_2$	$\hat{\beta}_3$	$\hat{\beta}_2 - \hat{\beta}_3$
±80 days	3,863	1.101 (0.235) [0.339]	0.862 (0.232) [0.376]	0.239 (0.072) [0.109]
±100 days (main)	4,775	0.898 (0.206) [0.277]	0.727 (0.203) [0.299]	0.171 (0.059) [0.096]
13 April 2009 – 10 January 2010	8,712	3.252 (1.272) [1.656]	3.122 (1.273) [1.658]	0.129 (0.030) [0.047]

Note: Standard errors clustered by day in parentheses and by week in brackets. The first three windows are symmetric around 13 April 2009; the last row uses the main pre-reform window and extends the post-reform window to 10 January 2010. The days 21–30 July are excluded where they fall inside the window; the first two windows end before July.

Table C2.
Reference specification, leave-one-week-out (€/MWh)

Week removed	NO2: $\hat{\beta}_2$	NO3: $\hat{\beta}_3$	NO2 − NO3: $\hat{\beta}_2 - \hat{\beta}_3$
3–4 Jan	0.896 (0.207) [0.279]	0.724 (0.204) [0.301]	0.171 (0.059) [0.096]
5–11 Jan	0.928 (0.210) [0.291]	0.753 (0.206) [0.313]	0.174 (0.060) [0.096]
12–18 Jan	0.967 (0.206) [0.277]	0.794 (0.203) [0.300]	0.173 (0.060) [0.096]
19–25 Jan	0.888 (0.211) [0.286]	0.716 (0.208) [0.307]	0.172 (0.060) [0.096]
26 Jan – 1 Feb	0.852 (0.210) [0.282]	0.680 (0.207) [0.303]	0.171 (0.059) [0.096]
2–8 Feb	0.798 (0.207) [0.267]	0.628 (0.204) [0.290]	0.170 (0.059) [0.096]
9–15 Feb	0.906 (0.209) [0.287]	0.736 (0.206) [0.308]	0.171 (0.059) [0.096]
16–22 Feb	0.993 (0.204) [0.265]	0.821 (0.201) [0.288]	0.172 (0.059) [0.096]
23 Feb – 1 Mar	0.897 (0.209) [0.280]	0.725 (0.206) [0.302]	0.172 (0.060) [0.096]
2–8 Mar	0.883 (0.211) [0.285]	0.713 (0.208) [0.306]	0.170 (0.059) [0.096]
9–15 Mar	0.917 (0.205) [0.283]	0.748 (0.202) [0.303]	0.168 (0.059) [0.096]
16–22 Mar	0.827 (0.210) [0.273]	0.660 (0.207) [0.295]	0.167 (0.059) [0.096]
23–29 Mar	0.886 (0.210) [0.283]	0.720 (0.207) [0.304]	0.166 (0.058) [0.096]
30 Mar – 5 Apr	0.911 (0.208) [0.283]	0.744 (0.205) [0.303]	0.168 (0.059) [0.096]
6–12 Apr	0.905 (0.210) [0.284]	0.735 (0.207) [0.305]	0.170 (0.059) [0.096]
13–19 Apr	0.796 (0.209) [0.269]	0.624 (0.206) [0.296]	0.172 (0.063) [0.104]
20–26 Apr	0.805 (0.209) [0.285]	0.659 (0.210) [0.319]	0.147 (0.060) [0.100]
27 Apr – 3 May	0.803 (0.204) [0.285]	0.616 (0.198) [0.300]	0.187 (0.064) [0.102]
4–10 May	0.920 (0.206) [0.290]	0.735 (0.202) [0.315]	0.186 (0.064) [0.102]
11–17 May	0.909 (0.215) [0.291]	0.740 (0.213) [0.316]	0.168 (0.063) [0.103]
18–24 May	0.978 (0.213) [0.281]	0.805 (0.210) [0.307]	0.173 (0.063) [0.104]
25–31 May	0.853 (0.211) [0.282]	0.671 (0.208) [0.307]	0.182 (0.063) [0.103]
1–7 Jun	0.923 (0.214) [0.290]	0.737 (0.211) [0.316]	0.186 (0.064) [0.103]
8–14 Jun	0.933 (0.215) [0.288]	0.752 (0.212) [0.313]	0.182 (0.063) [0.103]
15–21 Jun	0.980 (0.210) [0.278]	0.881 (0.202) [0.270]	0.099 (0.040) [0.069]
22–28 Jun	0.892 (0.213) [0.290]	0.765 (0.210) [0.313]	0.127 (0.060) [0.092]
29 Jun – 5 Jul	0.985 (0.213) [0.277]	0.781 (0.212) [0.311]	0.205 (0.062) [0.098]
6–12 Jul	0.931 (0.216) [0.289]	0.746 (0.213) [0.314]	0.185 (0.063) [0.103]
13–19 Jul	0.877 (0.208) [0.289]	0.690 (0.204) [0.312]	0.187 (0.063) [0.102]
20–22 Jul	0.891 (0.207) [0.279]	0.715 (0.204) [0.301]	0.176 (0.060) [0.097]

Note: Each row removes the calendar week indicated (the first and the last weeks are partial, and all dates are in 2009) and re-estimates the DiD coefficients on the remaining sample. Standard errors clustered by day in parentheses and by week in brackets.

Table C3.
Results with and without the episode of 21–30 July

	Episode excluded (main)	No exclusion
Days removed from the main window (21–22 July)	2	0
Observations per zone	4,775	4,823
$\hat{\beta}_2$	0.898 (0.206)	0.720 (0.277)
$\hat{\beta}_3$	0.727 (0.203)	0.754 (0.202)
$\hat{\beta}_2 - \hat{\beta}_3$	0.171 (0.059)	−0.033 (0.197)
Block-bootstrap interval for $\hat{\beta}_2 - \hat{\beta}_3$	[0.007, 0.378]	[−0.597, 0.339]
Mean spread $E[s]$	0.183 [0.072, 0.318]	−0.002 [−0.408, 0.269]
$E[s^+]$ / $E[s^-]$	0.223 / 0.040	0.218 / 0.220
$\hat{E}[a_2]$	0.118 [0.048, 0.203]	0.069 [−0.048, 0.176]
$\hat{E}[a_3]$	−0.065 [−0.117, −0.023]	0.071 [−0.095, 0.355]
$\hat{c}_2$ / $\hat{c}_3$	0.780 / 0.792	0.651 / 0.682
$\hat{\beta}_2 - \hat{\beta}_3$, sample extended to 10 January	0.129 (0.030)	0.021 (0.071)
Allocative gain, observed period (€)	24,335 [10,830, 42,515]	108,750 [14,207, 285,288]
Episode days assumed per year in the annual value	10	13.4
Allocative gain, annual value (ii) (€)	165,132 [53,962, 337,719]	194,902 [55,297, 439,115]

Note: Reference specification. Standard errors clustered by day in parentheses; 95% intervals in brackets (day bootstrap, 2,000 draws). The allocative gain is the deadweight loss removed (equation (4.9); $\varepsilon_s = 0.67$, $|\varepsilon_d| = 0.02$). In the main column, annual value (ii) values the 355 days of the year outside the episode at the average daily gain of the 263 days of the extended sample outside the episode and adds the gain of the episode of 21–30 July once (Section 8.1). In the no-exclusion column the average daily gain of the whole extended sample (273 days) is scaled to 365 days, which implicitly assumes 365 × 10/273 = 13.4 episode days per year, and the estimate is shown only to document the role of the episode.

Table C4.
The difference and the annual gain under alternative treatments of the episodes of price differences

Sample	$\hat{\beta}_2 - \hat{\beta}_3$	Annual value (ii) (€)
No exclusion	−0.033 (0.197)	194,902
Excluding 22 July only	0.156 (0.060)	166,685
Excluding the episode of 21–30 July (main)	0.171 (0.059)	165,132
Main, and the episode of 17–21 June	0.088 (0.040)	157,742
Main, and the episodes of 17–21 June and 21–23 April	0.054 (0.032)	153,153
All episodes inside the window (21–23 April, 13 May, 17–21 June, 25 June, 21–22 July)	0.029 (0.027)	149,625

Note: Reference specification; standard errors clustered by day in parentheses. Episodes are identified by the rule of Section 5. With 22 July alone excluded, the mean spread is 0.169 €/MWh and the allocative gain 24,792 € over the period. In the annual value (ii) the days excluded from the estimation are valued separately from observed

prices and added once, and the remaining days of the extended sample are scaled to the rest of the year (Section 8.1); the column therefore changes little across rows because the excluded days are always kept in the annual value.

Table C5.
The fifteen days with the largest allocative gain, sample with no exclusion

Day	Hours with different prices	Mean spread (€/MWh)	Largest absolute spread (€/MWh)	Mean price NO2 (€/MWh)	Mean price NO3 (€/MWh)	Allocative gain (€)	Share of total (%)
22 Jul	24	−17.108	30.14	17.31	34.41	83,958	77.2
23 Apr	6	2.095	29.16	41.26	39.17	5,971	5.5
21 Jun	17	3.873	9.81	33.72	29.84	4,253	3.9
21 Apr	11	2.059	10.29	42.30	40.25	2,549	2.3
20 Jun	18	2.092	8.77	33.74	31.65	1,645	1.5
19 Jun	14	1.672	8.60	33.99	32.32	1,577	1.5
13 May	5	1.137	7.57	38.37	37.23	1,495	1.4
17 Jun	6	1.250	7.91	36.35	35.10	1,288	1.2
25 Jun	6	1.117	7.29	36.52	35.40	870	0.8
20 May	5	0.747	5.91	38.02	37.27	770	0.7
21 Jul	15	−1.191	2.64	32.68	33.88	457	0.4
17 Apr	3	0.407	5.02	36.48	36.08	426	0.4
22 Jun	6	0.805	4.94	36.68	35.88	419	0.4
28 Jun	9	0.857	4.36	35.54	34.68	391	0.4
24 Jun	6	0.583	4.49	36.53	35.95	337	0.3

Note: All days are in 2009. Days ranked by the allocative gain of the central elasticities ($\varepsilon_s = 0.67$, $|\varepsilon_d| = 0.02$) in the post-reform sample with no exclusion; 22 July accounts for 77% of the total.

Appendix D. Descriptive statistics

Statistics for the post-reform window (13 April – 22 July 2009, with 21 and 22 July excluded).

Table D1.
The NO2–NO3 spread by month

	April (from 13th)	May	June	July (1–20)	Whole
Hours	432	744	720	480	2,376
Hours with equal prices (%)	93.3	96.6	77.2	83.3	87.5
Mean spread s (€/MWh)	0.296	0.080	0.400	−0.085	0.183
Mean price NO2 (€/MWh)	35.649	33.908	35.951	35.571	35.180
Mean price NO3 (€/MWh)	35.353	33.829	35.552	35.656	34.997

Note: Spread = NO2 price − NO3 price; hours with both prices available. The days 21 and 22 July are excluded.

Table D2.
Distribution of the NO2–NO3 spread after the reform

Statistic	Value
Hours	2,376

Statistic	Value
Mean (€/MWh)	0.183
Standard deviation (€/MWh)	1.230
Minimum (€/MWh)	−1.850
Median (€/MWh)	0.000
95th percentile (€/MWh)	0.870
99th percentile (€/MWh)	6.590
Maximum (€/MWh)	29.160
Hours with equal prices (%)	87.5
Hours with $s > 0$ (%)	7.2
Hours with $s < 0$ (%)	5.4
Mean of s^+ (€/MWh)	0.223
Mean of s^- (€/MWh)	0.040

Note: Spread $s_t = P_{2t} - P_{3t}$; $s^+ = \max(s, 0)$ and $s^- = \max(-s, 0)$. Means of s^+ and s^- are over all hours.

Table D3.
Flows and transfer capacities on the new interfaces, post-reform window

	Mean	*Hours with net import (%)*	*Hours with net export (%)*
Panel A: net flows (MW; positive = net import of the first area)			
NO2 from NO3	268.3	90.3	0.0
NO2 from NO1	66.5	65.2	19.2
NO2 from SE	55.2	22.6	10.1
NO3 from SE	−80.4	39.6	54.6
Panel B: transfer capacity (MW)		*Hours with zero capacity (%)*	
NO3 to NO2	656.5	0.0	
NO2 to NO3	0.0	100.0	
NO3 to SE	657.8	0.0	
SE to NO3	504.0	0.0	

Note: 2,376 hours; the days 21 and 22 July are excluded. In Panel A, the shares are the percentages of hours with a positive and a negative net flow of the first-named area with the partner.

Table D4.
Reservoir fill ratios

Series	Pre-reform	Post-reform	Change
Central Norway (reference series)	0.839	0.888	+0.049
Southern Norway (reference series)	0.903	0.950	+0.047
Former NO2 (Centre and North)	0.960	0.970	+0.010

Note: Means of daily values over the pre-reform window (3 January – 12 April 2009) and the post-reform window (13 April – 22 July 2009, with 21 and 22 July excluded). The fill ratio is the aggregate fill divided by the historical median of the same ISO week; the series are defined in Section 5.

Appendix E. Welfare

Table E1.
Allocative gain: sensitivity to sample and calculation (central elasticities)

Scenario	Observed period (€)	Relative to reference
Reference (episode of 21–30 July excluded)	24,335	1.00
No exclusion	108,750	4.47
Without the 10 hours with the largest gain	14,164	0.58
Without the 24 hours with the largest gain	8,412	0.35
K_{it} computed with the NO2 price for both zones	22,230	0.91
K_{it} computed with the NO3 price for both zones	28,616	1.18

Note: The reference covers 99 days and the no-exclusion scenario 101 days. The exclusions of the largest hours are made on the reference sample. Intervals for the reference are in Section 8.1 and for the no-exclusion scenario in Table C3. With no exclusion, K computed at the NO2 price for both zones gives a gain of 244,466 € against 108,750 €.

Table E2.
Transfers between consumers and producers (€)

	Observed period (99 days)	95% interval	Annual value (ii)	95% interval	No exclusion (101 days)	95% interval
Consumers, NO2	−515,367	[−886,549, −223,455]	−1,073,900	[−1,816,199, −431,697]	−322,822	[−781,792, 168,433]
Producers, NO2	+337,518	[127,843, 601,782]	+775,056	[247,357, 1,373,018]	+168,210	[−240,553, 516,514]
Consumers, NO3	+227,547	[90,540, 394,392]	+142,515	[−687,921, 758,815]	−171,893	[−1,038,756, 340,352]
Producers, NO3	−273,467	[−484,895, −93,668]	−309,926	[−1,021,263, 557,158]	+141,650	[−416,641, 1,058,462]
Net, consumers (NO2 + NO3)	−287,820		−931,386	[−1,491,713, −476,171]	−494,715	
Net, producers (NO2 + NO3)	+64,051		+465,129	[144,767, 964,791]	+309,860	
Sum of the net transfers	−223,769		−466,256		−184,854	

Note: First-order changes from equation (8.1), reference sample, central elasticities. Intervals are 95% percentile intervals from 2,000 bootstrap draws over days. Annual value (ii) values the 355 days of the year outside the episode of 21–30 July at the average daily value of the 263 days of the extended sample and adds the episode once, as observed.

Table E3.
Allocative gain by month, extended sample (€)

Month	Hours	Hours with equal	Mean spread	Allocative gain (€)	Share of total
April 2009	432	93.3	0.296	9,472	6.5
May	744	96.6	0.080	2,688	1.8
June	720	77.2	0.400	11,776	8.1

Month	Hours	Hours with equal	Mean spread	Allocative gain (€)	Share of total
July (outside the	504	81.3	−0.111	611	0.4
August	744	84.4	0.129	6,085	4.2
September	720	96.9	0.003	407	0.3
October	745	89.1	0.339	23,182	15.9
November	720	98.9	0.019	515	0.4
December	744	99.9	0.001	2	0.0
January 2010	240	87.9	0.144	596	0.4
21–30 July (episode)	240	38.3	−2.814	90,442	62.0
Total	6,553			145,776	100.0

Note: Sample extended to 10 January 2010, with the days 21–30 July excluded; central elasticities ($\varepsilon_s = 0.67$, $|\varepsilon_d| = 0.02$). The total is the annual value under assumption (i) of Section 8.1.

Table E4.
Annual allocative gain: calculation of the slopes and treatment of the episode (€)

Calculation of the slopes	Normal days	Episode (10 days)	Share of 22 July in the episode (%)	Annual value (i)	Annual value (ii)	Episode share of (ii) (%)
Own-zone prices (reference)	55,334	90,442	93	145,776	165,132	55
NO2 price for both zones	49,971	228,627	97	278,598	296,078	77
NO3 price for both zones	64,851	62,118	90	126,969	149,655	42

Note: Central elasticities. Normal days are the 263 days of the extended sample outside the episode of 21–30 July. Annual value (i) is the extended sample as observed, including the episode; annual value (ii) values the 355 days outside the episode at the average daily gain of the normal days and adds the episode once.