How are Day-ahead Prices Informative for Predicting the Next Day's Consumption of Natural Gas? Evidence from France

Arthur Thomas,[a] Olivier Massol,[b] and Benoît Sévi[c]

Forecasting the next day's consumption of natural gas has very important implications for both the cost-efficient operation of the gas pipeline network and the possibility to use that infrastructure to supply short-term flexibility services to a renewable-dominated power sector. Because of their poor accuracy, the performance of the demand forecasts issued by Transmission System Operators (TSO) has recently emerged as a very important issue in regulatory debates and has motivated the adoption of dedicated incentive schemes in several countries (e.g., Italy and the UK).

By construction, the day-ahead wholesale markets for natural gas are supposed to provide transparent spot prices that should reflect the market participation of all concerned economic agents (suppliers, trading firms, and consumers) and thus their expectations about future demand levels. The question examined in this paper is therefore whether the information in these day-ahead prices is rich enough to generate accurate predictions of the next day's consumption of natural gas (relative to the ones provided by TSOs).

To answer this question, we investigate the interactions between natural gas consumption and the information contained in day-ahead market data. We propose a simple specification that models the variations in daily gas consumption as a function of two variables (the price of natural gas and the spark ratio measuring the relative price of electricity to gas) and their lagged variations. By construction, this model captures the essential features of daily gas consumption and in particular the nonlinearities resulting from power dispatching.

As an application, we examine the case of France over the 2015–2018 period. We first estimate our proposed specification using a dataset covering the period April 1, 2015–December 31, 2016 and then use it to compute out-of-sample forecasts. This is the first attempt to model and predict France's gas demand at the daily frequency. Our results first document the existence of a long-run relationship between demand and spot energy prices. We also provide evidence of the pivotal role of the spark ratio which is found to have an asymmetric and highly nonlinear impact on demand variations. Lastly, we show that our simple model is able to generate predictions that are considerably more accurate than the forecasts published by infrastructure operators. Our results thus suggest that accounting for the information contained in day-ahead prices represents a promising avenue to improve the performance of the gas demand forecast and also points to some deficiencies in the infrastructure operators' forecasting activities.

Though our discussion is confined to the French case, the results are relevant for other countries engaged in a transition toward less carbon-intensive energy systems. Indeed, the gas consumption emanating from the country's power sector exhibits large and sudden variations because the French Combined Cycle Gas Turbines (CCGT) plants are primarily dispatched as peaking units, which leads to large flow variations in the gas network as these plants ramp up and down. That

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situation thus prefigures the new role assigned to gas-fired power plants in a previously thermoelectric-dominated power system that experiences a massive penetration of renewable generation.

Stranded Asset Risk and Political Uncertainty: The Impact of the Coal Phase-out on the German Coal Industry

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To comply with the Paris Climate Agreement (COP21), the German government convened the Coal Commission to find a solution for coal-fired power plants, the largest emitters of carbon dioxide in Germany. It involved the most important stakeholders from society, industry and environmental associations. The Commission suggested to phase-out coal-fired power plants by 2038. This raises the question about how the coal-phase-out would impact the German coal industry valuation.

Within this context, our study aims at assessing the value of stranded coal-fired power plants in Germany based on a scenario comparison which compares three scenarios (a slow decommissioning at the end of the technical lifetime in 2061, the highly probable phase-out by 2038, and an accelerated phase-out by 2030). For each scenario, we run a simplified market model along with an integrated Monte Carlo simulation to reveal the uncertainty of future developments. Based on the different valuations of the coal-fired power plants in each scenario, we calculate the loss in valuation due to the (earlier) phase-out.

The results show an overall stranded asset value of €2.6 billion given the phase-out by 2038 and additional €11.6 billion if the phase-out is brought forward by 8 years from 2038 to 2030. In particular, lignite-fired power plants cause the highest loss in valuation due to an early phase-out in 2030. Higher carbon prices lead to their loss in base load position in the merit-order, making them unable to cover their fixed costs when operating only during peak load times. A coal phase-out by 2038 as proposed by the Coal Commission would thus help German hard coal and lignite industries to save €11.6 billion, but Germany will not be able to meet its emission reduction goals set in the 2015 Paris Climate Agreement. Our scenario analysis also demonstrates that the feed-in from renewable energy sources (and thus a decline in the residual base load) and higher carbon prices would lower the hard coal and lignite industry valuations.

Our study shows two important implications of stranded assets. First, physical assets become stranded through losses in revenues, as outlined within the case study on the coal phase-out in Germany. This contributes to a broader understanding of stranded assets that are shifted from unanticipated write-downs to rather cash-effective valuation impacts. Second, we evidence the interconnection between physical assets and financial assets, which adversely affects carbon-intensive sectors. The devaluation of examined shares poses a significant financial risk to companies, financial institutions, and investors. Due to this political uncertainty of the pathways and in progressive policy measures, these climate-related risks would have to be incorporated into the investment decision-making process.

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Riding the Nordic German Power-Spread: The Einar Aas Experiment

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In 2018 the financial world noticed the Norwegian trader Einar Aas who seemed to effortlessly exploit differentials in the risk premia in Nordic and German electricity futures, hoping that over time, due to better integration of the two markets, these differentials would diminish, which would then generate spectacular profits. It looked good for Einar Aas for a long time, but then a wet weather forecast for Norway in September 2018 (in combination with rising emission prices) resulted in futures prices moving into the wrong direction, which brought his strategy to a fall. It was a spectacular fall, creating a loss of 170 million USD, enough to shake up Nasdaq clearing and raising concerns about financial contagion and a possibly bigger crisis.

Inspired by the initial success and eventual failure of Einar Aas' trading strategy, we investigate the question whether there is evidence for possible arbitrage from engaging in both the Nordic and German electricity futures markets simultaneously and how a market beating trading strategy could be constructed and assessed against benchmarks. To do this, we first assess the risk premium and relevant Sharpe values for the two markets and observe significant differences. This is followed by a discussion as to how far the different risk premia and Sharpe values alone are evidence of arbitrage. The answer is, they are not. However, in form of a realistic experiment which is based on the dataset relevant to the Einar Aas case, we then demonstrate that an intelligently chosen suitable pairs trading strategy (long-short) can indeed produce positive alphas within a CAPM setting. This presents evidence for possible arbitrage and shows that we have identified a market beating strategy, at least within a CAPM context.

Of course increasing popularity of the relevant long-short strategies and simultaneous engagement in the two markets by a large number of agents will eventually, through balancing supply and demand, eradicate the sort of arbitrage strategies discussed here. Our paper therefore contributes knowledge that can eventually improve market efficiency and prevent crises.

Time-Varying Term Structure of Oil Risk Premia

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A commodity risk premium is defined as the difference between the expected spot price and the futures price for the same maturity. Given that spot market price expectations are not observable, estimating their level and behavior may provide valuable information to market participants.

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For agents who treat commodities as an asset class it may give insight on investment returns. It may also shed light on some public policy implications since the risk premia is related to some macroeconomic and commodity market variables. Even though the existence of risk premia is generally accepted in the literature, there is no consensus on their magnitude, behavior and appropriate estimation procedure.

We propose a framework for estimating the time-varying commodity risk premia from multi-factor models using futures prices and analysts' forecasts of spot prices. The model is calibrated for oil using a 3-factor stochastic commodity-pricing model with an affine risk premia specification.

Two different data sources are used to estimate the oil risk premia: Futures prices and analysts' forecasts. The estimation period ranges from January 2010 to June 2017 allowing us to capture significant variations in macroeconomic trends. WTI crude oil futures prices are obtained from NYMEX for maturities between 0 to 9 years. Analysts' forecasts are obtained from Bloomberg for short- and medium-term (up to 4 years) data and from the US Energy Information Administration for longer maturities.

From the annualized risk premia term structures obtained three things stand out. First, risk premia varies stochastically through time suggesting the possibility that they could be influenced by some market variables. Second short-term risk premia tend to be higher than long-term risk premia, suggesting that on average investors have higher hedging demands for short-term contracts. Finally, risk premia volatility is much higher for short maturities hinting higher disagreement between market participants for shorter term contract prices.

To understand the stochastic behavior of oil risk premia we chose a set of macroeconomic variables and oil market variables previously used in the literature and test for their explanatory power on the risk premia.We find that oil inventories, hedging pressure, and the bond default premium have a positive and significant effect on the risk premia. Also, the interest rate term premium has a negative effect on the risk premia. Finally, the 5-year Treasury bill shows an unexpected positive effect on the risk premia, which could be due to the extremely low rates prevailing during our sample period, which may affect the way in which interest rates relate to business cycle.

Energy Efficiency and Productivity: A Worldwide Firm-level Analysis

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Improving energy efficiency is a growing policy priority for many countries in the world and is widely recognized as one of the most cost-effective and readily available means of addressing numerous energy-related issues such as energy security, the socio-economic impacts of high energy prices, and climate change. The launching of the so-called "Agenda 2030" has introduced the energy issue to the Sustainable Development Goals (SDGs). Among other things, SDG 7 establishes the need to prioritize energy-efficient practices and, specifically, to double the global rate of improvement in energy efficiency by 2030 (Target 7.3). Since manufacturing and industrial activities are

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among the primary energy users and are thus also responsible for CO_2 emissions, industrial firms have been put under political and social pressure to re-examine their energy awareness practices and move towards greater energy efficiency.

Although important to policymaking, very few academic studies measure the contribution of energy efficiency to firm performance. Most studies are carried out at the aggregate level or focused on developed economies, whereas relatively few firm-level analyses have been carried out for developing countries. This work aims to fill this gap. Taking advantage of the national representative World Bank Enterprise Survey (WBES) data, we contribute to the current literature by providing one of the most comprehensive firm-level analyses to date in terms of geographical coverage for the period 2006-2018. To this end, we apply a standard constant return to scale Cobb-Douglas production function expanded to energy efficiency.

Our findings show a positive relationship between energy efficiency and firm-level productivity worldwide, although with some degree of heterogeneity in firm size, industry, and geographical regions. These results are robust to a set of sensitivity tests and when using different techniques. They are consistent with those obtained by previous firm-level analyses, although the latter are focused on a narrower set of countries, do not control for panel dimension, and analyze different time-spans.

This work provides empirical support for the messages conveyed by international institutions regarding the positive relationship between environmental actions and firm performance, thus supporting the efforts to improve the private sector's energy efficiency. It shows that the implementation of Agenda 2030 is not only a fundamental step for sustainable development, but also a tool for fostering firm-level productivity.

Reconciling Hotelling Resource Models with Hotelling's Accounting Method

Robert D. Cairns[a] *and John M. Hartwick*[b]

In recent decades, economists have taken increased interest in measuring (accounting for) the many capital inputs to economic activity based on economic theory. Innumerable studies have striven to make the national accounts more comprehensive by including assets, such as natural and environmental assets, for which market prices do not exist or are not adequate. Among the first studied were nonrenewable resources, which had assumed great importance during and after the oil crises of the 1970s.

Taking center stage has been a quest to determine theoretically supported measures of net product, net income, net investment and net depreciation, which directly affect human well-being, as opposed to gross measures. With few exceptions, the theory has utilized optimal-control methods applied to mathematical expressions for the path of an economy through time.

A finding of these economic investigations is that only the monetary values of "real" variables should be reported in accounting statistics. Because they are *pure price effects*, capital gains should be excluded. This finding is of practical importance for reported income and product in resource-producing regions. According to the theory of nonrenewable resources enunciated by Harold Hotelling in 1931 and significantly examined since, the prices of oil and gas, uranium, noble and

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base metals, etc. will (at least eventually) increase through time as they are depleted, so that the values of in-ground deposits will increase commensurately, producing capital gains.

In this paper, we revisit this issue. A general investigation demonstrates that the neglect of capital gains is inconsistent with the fundamental property of depreciation that an asset's depreciation over time must sum to its original value, as enunciated by Hotelling in a 1925 paper. A modification of the underlying mathematical relationships that is consistent with the property lends theoretical support to including capital gains. Capital gains exist if time plays a direct role in mathematical expressions, that is to say, if the model *non-autonomous*. In a non-autonomous model, capital gains should be included. We argue that, in practice, time plays a direct role.

To grasp the implications more fully, we study six canonical models from the economics of nonrenewable resources. Even in the simplest models, of a competitive market or a planner's solution, non-autonomy raises fine distinctions. In cases where aggregation is subtle, namely, the stock effect or durability of the resource, mathematical representation can mask the effects of non-autonomy. Moreover, if a firm faces u-shaped average extraction cost, an unpriced, unobserved asset can affect accounting. The economic and accounting implications of such assets are pursued in a separate section. We are able to clarify how certain assets may be theoretically discernable but not given accounting prices. Once we adjust for unobservable values, we obtain expressions for net income, product, investment and depreciation that take a familiar form but include capital gains.

Pipes, Trains and Automobiles: Explaining British Columbia's High Wholesale Gasoline Prices

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Starting in mid-2015 gasoline prices in British Columbia Canada began increasing relative to cites in neighboring regions (specifically Edmonton Alberta and Seattle Washington). This eventually prompted a formal investigation by the British Columbia Utilities Commission and a two-part report wherein the Commission identified an "unexplained difference of approximately 13 cpl [cents per liter]" between Vancouver and Seattle prices. The British Columbia Utilities Commission investigation and report strongly imply suspicion of anti-competitive conduct (collusion and price fixing) in the wholesale fuel market.

Elsewhere in North America the combination of a changing geographic pattern of North American crude oil production (the "U.S. shale-boom") and a lack of new investment in pipeline capacity has led to increased interest in inter-regional price differences and arbitrage conditions in crude and refined petroleum product markets. But existing work in the area has been primarily empirical, focusing on relationships between regional price series, with little or no attention paid to individual firm conduct. This level of abstraction is appropriate in investigating general regional pricing patterns, but insights on production and transportation cost pass through, refinery market power and potential competition policy issues require a more detailed examination of firm level conduct.

In this paper I examine the effect of transportation constraints on imperfectly competitive regional wholesale fuel and crude oil markets. I pair a general theoretical model (an extension of the workhorse Cournot oligopoly model) with an empirical analysis focused on the recent western Canadian experience of diverging relative wholesale gasoline prices in British Columbia and Alberta. The empirical analysis makes use of a natural experiment that occurred in 2015 when a regulatory rule modification caused a reduction in capacity for refined product shipments on the

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The results of this exercise suggest that the pass-through rate of marginal transportation costs is not one-to-one due to the imperfectly competitive nature of regional markets. The analysis also shows that reductions in pipeline capacity may reduce the rate of pass-through of other marginal cost components (i.e.- those associated with production rather than transportation) if the supply curve for alternative transportation modes is upward sloping (i.e.- not perfectly elastic).

It is apparent from the British Columbia Utilities Commission report that the combination of increased wholesale prices and reduced pass through of production costs can give the appearance of anti-competitive conduct (collusion and price fixing) even though firms' competitive strategies (response functions) remain unchanged. This is an important insight for regulators and competition policy authorities.

The theoretical model and empirical analysis indicate that insufficient pipeline capacity for refined product shipping from Edmonton to cities in BC caused an additional wholesale gasoline price increase in Vancouver of 10 cents per liter (assuming perfectly elastic supply of non-pipeline transportation options) or up to 18 cents per liter (assuming an upward sloping supply of non-pipeline transportation). These price increases occur due to normal competitive oligopoly conditions (that is, all firms are making quantity choices consistent with a Cournot best response function).

While the empirical analysis is specific to western Canada, the analytical results can be extended to other regional markets for liquid or gaseous hydrocarbons as the analysis follows from a generalized extension of an otherwise standard Cournot oligopoly model. Applications beyond hydrocarbon markets are possible as well given that the model is general enough to apply to any oligopoly market wherein competitors face a common but discontinuous supply curve for an input good required to produce and deliver an output good.

Investigating Price Formation Enhancements in Non-Convex Electricity Markets as Renewable Generation Grows

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Increased Variable Renewable Electricity (VRE) supply to the grid results in more frequent and faster fluctuations in net demand. This increases the demand for operational flexibility, the ability of the grid to adjust to these conditions to ensure reliable and economically efficient supply of net demand. Conventional generators are called on to provide greater levels of operational flexibility, i.e., cycle more often and endure more frequent and significant ramp up and down events. It is not well-understood if the price formation process in wholesale energy markets today will appropriately remunerate and incentivize the greater levels of flexibility that will be required as VRE penetration levels grow.

Using a custom-built scale-model of the PJM electricity grid operations, we explore how greater wind penetration affects the efficiency of conventional marginal pricing and its ability to remunerate operational flexibility. We also explore the degree to which alternative pricing schemes that seek to minimize out-of-market payments, remunerate operational flexibility. To investigate these questions, we simulate and analyze wholesale electricity market operation outcomes for a

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continuous 365-day period with existing and alternative pricing schemes at different wind penetration levels.

We find that conventional pricing fails to adequately compensate the added operational flexibility needed at higher wind penetrations. Load-following generators that supply most of the cycling and ramping services do not recover their ramping costs. Moreover, they frequently rely on out-of-market uplift payments to recover their short-run generation costs. Our analysis also exposes an interesting paradox. The higher demand for operational flexibility triggers additional unrepresentative price events, dramatically increases price suppression, and limits the energy market's ability to remunerate flexibility. The above outcomes suggest that load-following generators have incentives to withhold their inherent flexibility under conventional pricing schemes so as to avoid additional ramping costs and minimize revenue shortfalls.

Minimum uplift pricing can largely overcome these deficiencies by yielding cost-representative prices that efficiently increase inframarginal revenues such that most load following generators have positive net profits after deducting their ramping costs. Among the alternatives we investigated, Approximate Convex Primal Prices (A-CPP), which closely approximate Convex-Hull Prices, is the most efficient alternative for minimizing the unrepresentative price events and out-of-market payments and enhancing incentives for flexible performance.

In anticipation of higher levels of VRE on grids, ISOs should closely monitor prospective changes in cycling patterns of load-following generators and introduce new pricing schemes that reward flexible performance in the energy market and discourage flexibility providers from submitting inflexible bids. Given that convex-hull pricing is challenging to implement in practice, the potential of load-following products in improving cycling patterns of conventional generators should be explored as an alternative for enhancing market remuneration of flexibility. Future market design enhancements must be able to encourage resource investment and retirement decisions that satisfy the grid's growing operational flexibility requirements for dealing with VRE generators. Finally, the impacts of new energy pricing schemes and/or load-following products are likely to be insufficient to deal with resource adequacy issues that emerge as wind penetration grows. To address such concerns, ISOs should consider other market constructs that ensure complete capital cost recovery for the investments that are essential for deeply decarbonizing electricity grids.

Design of Renewable Support Schemes and Windfall Profits: A Monte Carlo Analysis for the Netherlands

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Subsidies have become highly popular as a tool to increase the production of renewable energy and to realize climate-policy objectives. These schemes contribute successfully to the latter but at the same time involve sizable government expenditures. For instance, in the electricity sector alone, which represents less than 25% of total energy use and is one of the least costly sectors to decarbonize, the governments of the EU countries in 2017 jointly spent 78.4 billion or 0.5% of GDP on subsidies for renewables. This contributed to a renewable-electricity share of 30%, illustrating that achieving, for instance, the long-term EU climate goals (net-zero emissions in 2050) will require vast additional efforts. In turn, this illustrates that it is of critical importance to design subsidy schemes in a cost-efficient manner. From the perspective of the government budget, cost-efficient

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subsidies imply not only stimulating low-cost technologies but also not paying more than necessary for a specific project.

This paper analyzes the degree to which subsidized renewable energy projects yield private benefits in excess of what is required for investors to be willing to undertake them. We refer to these "excessive" private benefits as windfall profits. Limiting windfall profits implies that the compensation for a project should not exceed the project's levelized-cost-of-electricity (LCOE). A key challenge for achieving this is that, due to information asymmetry between governments and investors, it is prohibitively costly to observe both the true LCOE and revenues of individual renewable electricity projects. This hinders tailoring the subsidy at the minimally required level for each project. As a consequence, most governments provide a uniform subsidy for renewable electricity or a specific technique (e.g. on-shore wind). This means that projects with favorable characteristics will be remunerated in excess of their LCOE and, as a consequence, earn windfall profits.

Our empirical analysis investigates the extent to which the Dutch feed-in premium scheme has resulted in windfall profits to on-shore wind projects. We analyze the period 2003–2018, in which a number of design adaptations were implemented that specifically aim at limiting windfall profits. Specifically, for 2003, 2009 and 2018, using Monte Carlo simulations, the analysis estimates the distributions of the required subsidy across virtually all *potential* on-shore wind projects (i.e. all projects that were available), and compares them to the granted subsidies. In addition, for 2018, the paper estimates the distribution of the required subsidy of the 187 *actual* projects that were granted subsidies. We compare these estimates with the results for *potential* projects to evaluate how successful investors are in seeking out the most profitable projects.

We find that the degree of windfall profits has decreased considerably over time. Specifically, the share of *potential* investments with an actual subsidy above what would have been required decreased from 81% in 2003 to 68% in 2018. At the same time, the average windfall profits decreased from 2.42 ct/kWh to 0.85 ct/kWh. These decreases followed from two adaptations in the scheme: differentiating in subsidy levels between on-shore wind projects on the basis of the turbine location as well as tighter estimates by the government of the required subsidy for a reference project. In relative terms, however, average windfall profits were at 32% of the actual subsidy in 2018 not lower than the 31% in 2003. Hence, despite that windfall profits have decreased in absolute terms, they have not disappeared, and remained constant in relative terms. Furthermore, analyzing *actual* investments in 2018, it appears that investors successfully seek out the most profitable investments. 85% of the actually subsidized investments generates windfall profits, and, at 1.28 ct/kWh, which equals 50% of the actual subsidy, the average windfall profits of *actual* investments are 50% higher than that of the *potential* investments. This is likely due to investors having better information about individual characteristics of on-shore wind projects than the government, enabling them to seek out the most profitable investments.

Several policy lessons can be drawn. For the Dutch government, the results imply that, at least theoretically, the Dutch government may realize the same amount of projects with 50% of the current subsidy expenditures, or considerably more projects given the current expenditures. Generally, for all governments, differentiating in the subsidy level between projects contributes to mitigating windfall profits and to reducing expenditures without reducing the number of realized projects. Such design improvements help to make renewable-energy policy more cost efficient.

Market-based Redispatch may result in Inefficient Dispatch

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Today, in most industrialized countries, electricity markets have been liberalized, with only transmission services being subject to regulation. Thus, free market interaction governs supply and demand while regulated transmission system operators (TSOs) operate the network. As the dispatch resulting at the day-ahead electricity wholesale spot market often does not entirely reflect the relevant network constraints, the TSO is typically engaged in congestion management, which follows day-ahead spot market trading. In the case of spot market allocations that are infeasible for the given network, the TSO intervenes ex-post and adjusts the traded quantities to restore network feasibility. These short-run operations are commonly called redispatch operations.

To determine allocations and reimbursements of firms in the redispatch procedure, two types of redispatch systems are mainly implemented and discussed in the literature. Under a cost-based redispatch system (CBR) – as it is applied in Austria, Switzerland, or Germany – variable cost of production is the basis for redispatch payments. As a CBR compensation is purely based on the incurred short-run cost of redispatched producers, it clearly aims at minimizing congestion management cost of the TSO. In contrast, under market-based redispatch or counter-trading (MBR) the TSO procures redispatch quantities at the different nodes in a market environment. Depending on the specific pricing rules applied (marginal pricing or pay-as-bid pricing), the compensation of market participants can be different from short-run cost. Versions of counter trading are used in the Nordic market (comprising Denmark, Finland, Norway, and Sweden), in the Netherlands, and in the United Kingdom.

The different redispatch systems induce different levels of redispatch cost for the TSO. The present analysis focuses on potentially changed incentives of the TSO to choose redispatch adjustment quantities under the different redispatch systems. TSOs in electricity markets are typically regulated based on an incentive regulation, which establishes limits for the prices that can be charged to customers for transmission services. A reduction of cost incurred by the TSO allows for larger profits, providing incentives for an efficient cost reduction. In many cases, TSOs thus have incentives to minimize their spendings, including those resulting in the redispatch process, which is the case, e.g., in the UK or Germany. As our analysis indeed shows, an incentive regulation inducing the minimization of redispatch cost as the objective of the TSO can be highly problematic in case of MBR since it may result in distorted redispatch choices. In contrast, in case of CBR incentives of the TSO to minimize redispatch cost yield undistorted redispatch decisions and, therefore, maximize welfare.

To analyze those important issues in more detail, the paper at hand introduces a model that allows to assess the short-run impact of the different redispatch regimes on the redispatch decisions taken by the TSO in a liberalized electricity market. We consider a spot market with a uniform market price for the case of elastic spot market demand and multiple generation technologies at the different network nodes. Subsequent redispatch is applied to deal with network congestion. Assum-

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ing that the TSO is incentivized to minimize redispatch cost, we explicitly compare CBR to two different variants of MBR. The model is applied to a simple two-node network as it is often used in the literature as well as to a setting with three nodes and more complex physical network constraints.

For the case of only two-node networks, we show that both CBR and MBR result in identical welfare-maximizing outcomes, which is in line with existing literature. As a main result, for networks with at least three nodes we demonstrate that in contrast to a CBR mechanism, redispatch cost minimization of the TSO may not always imply welfare maximization in the case of MBR. We show that the TSO might have incentives to decrease MBR redispatch cost at the expense of market efficiency. Based on this finding, we finally emphasize the importance to establish a regulation where the TSO is obliged to implement the welfare maximizing (instead of the redispatch cost minimizing) dispatch for electricity markets that use MBR. This would result in the same efficient outcomes as under a CBR regime. Observe that our results do not require the assumption of strategic firms, but already hold for the standard case of perfect competition.

Fat Tails due to Variable Renewables and Insufficient Flexibility: Evidence from Germany

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The large-scale integration of renewable energy sources (RES) requires flexibility from power markets in the sense that the latter should quickly counterbalance the renewable supply variation driven by weather conditions. RES supply, being a variable source of power production, poses challenges to power markets as they are often not flexible enough to counterbalance RESs variation in production volumes, since power storage is insufficient and power demand is inelastic.

Research shows that the volume of renewable energy in the supply system affects the mean and volatility of power prices. Using extreme value theory, we extend this view and show that the level of wind and solar energy supply affects the tails of the electricity price distributions as well, and that it does so asymmetrically. The higher the supply from wind and solar energy sources, the fatter the left tail of the price distribution and the thinner the right tail. In other words, we demonstrate that the tails of the power price probability distribution are fatter when the supply of flexibility is low. Such moments of low power flexibility occur when both the reserve margins of non-intermittent suppliers and RES supply are either at low or at high levels. More specifically we find support for our claims that i) during periods of high share of RES, the left tail is fatter than the right tail and the difference in fatness will be more pronounced when demand is lower, and ii) during periods of low share of RES, right tail is fatter than the left tail and the difference in fatness will be more pronounced when the demand is higher. When we focus separately on the share of wind and solar supply, instead of aggregate supply from RES, we find the same results for wind and for solar.

Although it was already known that power prices are not normally distributed, this paper shows that the amount of non-normality in the tails, i.e. the tail fatness, can be forecasted by demand and volume of RES. For risk managers, this implies that risk models should be made conditional on those variables and one should use models in which the tail structure can be flexibly adjusted to the

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supply and demand conditions. This implies that one cannot rely on symmetric price distributions for risk management and for valuation of (flexible) power assets.

Furthermore, in order to achieve large-scale integration of RES in the power system, policy makers and market participants should have a clear understanding of the requirements for power system flexibility. This study provides insights into when, and to what extent, extreme prices occur depending on the electricity demand and RES supply, and thereby the demand for flexibility to adjust electricity supply through non-intermittent producers. The evidence in this paper suggests that we have to rethink the methods of subsidizing variable renewable supply such that they take into consideration also the flexibility needs of power markets.

Reciprocal Dumping under Dichotomous Regulation

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An essential ingredient to net-zero-emissions policies is to regionally integrate electricity markets. But electricity cross-border trades are often assessed as inefficient. We explain this inefficiency by the presence of a dichotomous regulation: producers are highly regulated in regards of their local activities, but weakly regulated when it comes to their exports. Such a dichotomy in regulation can be generalized to every economic sector, with varying intensity.

We provide a generic 2-player game theoretical framework where producers anticipate the impact of their exports on the clearing of regulated local markets. We model this as a two-stage game where the producers set their exports first. The second stage correspond to the local markets clearing where regulation is assumed to be the simplest marginal-cost-pricing in order to provide a theoretical benchmark. Thus, the regulation is harmonized between each country and non-discriminatory, but they are not coordinated. We characterize the subgame-perfect Nash equilibrium of the game and provide examples with functional forms.

Overall, dichotomous regulation in our framework leads producers to over-export in order to create scarcity on their home market. Hence, despite that local markets clear efficiently, the global equilibrium is inefficient. When the two jurisdictions are relatively symmetric, the producer in each jurisdiction prefer to dump overseas in order to raise its home price, resulting in reciprocal dumping. This equilibrium is Pareto-dominated by the efficient outcome. Ultimately, the trade regime between asymmetric local markets is determined by their relative price-elasticity. The lower the relative price-elasticity of a market with respect to another, the stronger is the incentive to dump for the local producer, and the stronger is the incentive to withhold for the foreign producer.

These results call for better coordination between the regulatory authorities of each jurisdiction. This is not generally the case in international trade, and our model can be seen as a building-block to derive optimal international trade policies. The European Agency for the cooperation of Energy Regulators (ACER) and their promotion of market coupling to foster the European Internal Electricity Market (IEM) is an example of such a high degree of coordination. Yet, market coupling results in automated flows, an approach not necessarily desired in more market-oriented regions, nor in other economic sectors.

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