Mathias Mier

European and German Electricity Prices in Times of Natural Gas Crisis*

KEY MESSAGES

- **Nuclear stretching operation in Germany until April 15, 2023 brings down German (European) power prices by 6.01 percent (1.51 percent) until April 15, 2023 and by 2.98 percent (0.65 percent) in 2023, saving 4.8 TWH (8.6 TWh) of natural gas and 3.3 Mt (4.5 Mt) of CO_2 emissions in 2023**
- **Nuclear extension in Germany until 2029 would bring down German (European) power prices by 7.31 percent (1.79 percent) in 2023 and 2.95 percent (0.92 percent) in 2024, saving around 6.6 TWh (12.9 TWh) of natural gas and 13.3 Mt (17.8 Mt) of CO_2 emissions in 2023**
- **Reduced 2022 hydropower generation and reduced 2022 French nuclear availability contributes 2.21 percent (32.3 percent) to 2022 German (European) electricity price increases**
- **Windfall tax is preferred to the revenue cap for "inframarginal" generators suggested by the European Commission**

Electricity is different from other goods because it is not sufficiently storable at reasonable cost, i.e., supply must match demand at every point in time to be transportable from supplier to consumer.[1] The overall importance of this constraint is reinforced by the fact that demand varies seasonally and daily, as does the supply from intermittent renewables generators (wind, solar, and hydro). Further complexity arises from the possibility of unpredictable power plant outages, ramping and start-up times/cost of different power plant types, and grid congestion constraints. However, electricity is the most homogenous good in the world because there is no quality difference; meaning that only the cost in combination with technological constraints (ramping up, start-up, congestion) and the availability pattern of a technology (solar peak at noon, higher wind in winter) are decisive.[2]

Mathias Mier

is an economist at the ifo Center for Energy, Climate and Resources.

[1] Natural gas is easily storable, as is gold, food, or iPhones.

[2] Indeed, electricity does not have the preference factor or social status that comes with food or iPhones.

* All calculations based on assumptions from October 10, 2022.

THE PRINCIPLES OF MARGINAL PRICING AND MERIT ORDER

Marginal costs are the variable part of cost that occur when a generator is used but not when it lies idle.[3] Generators are ordered according to their marginal cost: those with the lowest marginal cost (wind, solar, hydro, nuclear, lignite) are dispatched first, whereas generators with the higher marginal cost (coal, natural gas, biomass, oil) might be used only when demand is high (in peak times) or supply of intermittent generators (wind, solar, hydro) is low (Boiteux 1949; Steiner 1957; Joskow 1976). Such ordering of generators according to their cost gives the supply function and is called merit order. This merit order ensures the cost-optimal dispatch of generating units and provides the optimal long-run incentives to invest in specific technologies at the right locations. The market clears at the intersection of supply and demand, which results in a uniform price in the respective price zone for all dispatched generators, no matter the technology-specific variable cost. The margin between price and variable cost is used to cover the fixed cost of the specific generator.[4] This margin ensures that private investment decisions are socially optimal because private firms or investors, respectively, would invest in a specific technology as long as the margin is sufficient to cover their fixed cost.[5] Note that there are no incentives for generators not to reveal the true cost under such merit order with uniform pricing, because each generator would like to get dispatched as long as the price is above its own variable cost. Bidding below variable cost comes with losses when the resulting price is below own variable cost. Bidding above variable cost might lead to not getting dispatched; such behavior would risk potential revenues to cover fixed costs.[6]

PRINCIPLES INTO MARKET DESIGN

The nature of electricity and the principles of marginal pricing, as well as merit order ranking, spawned two

[3] Variable cost cover fuel cost, cost for CO_2 allowances, and variable operation and maintenance cost.

[4] Fixed cost cover investment cost, including equity cost with reasonable return-on-investments and financing cost, as well as fixed operation and maintenance cost.

[5] Socially optimal in the sense that also consumers are best off, i.e., electricity prices are lowest.

[6] Such bidding of true cost only holds under uniform pricing, but not when generators receive the price of their own bid. Under such a pay-as-bid system, generators do not reveal their true cost but bid above their variable cost. Indeed, it is optimal for generators to bid the expected price from a uniform price auction. The market cannot order generators according to their lowest cost and the resulting system is only optimal when private information about true cost is publicly available.

major philosophies in electricity market design (see Wilson 2002; Cramton 2017; Wolak 2020; Mier 2021). The bid-based approach is mainly applied in Northern America and combines a day-ahead market for optimal scheduling of power plants, given ramping and start-up constraints, with a real-time market for security-constrained economic dispatch that ensures the physical integrity of the demand-equals-supply constraint given all uncertainties that eventually arise. The exchange-based approach is mainly applied in Europe and combines a day-ahead with intraday and balancing markets that overtake the role of the real-time market from the bid-based approach. Theoretically, both systems are equivalent, but intraday and balancing markets show poorer pricing than real-time markets due to generally lower trading volumes (Cramton 2017). The bid-based approach often includes more complicated bid structures to ensure that the dispatch is indeed cost-optimal (ramping/start-up times/cost). The market settlement is not decentralized anymore because of the complicated bid structures. Instead, optimization models determine which generator is dispatched and determine electricity prices via shadow prices of the clearing constraint. The exchange-based approach often only has simple bid structures that do not account for ramping or start-up requirements. Both approaches are well tested and balanced over decades to achieve close to optimal market outcomes. Changes or fundamental revisions would require careful and very precise operations while the market still runs, which is comparable with open-heart surgery in a field hospital while artillery shells out the electricity supply.

CURRENT AND FUTURE PRICE SITUATION

Markets run into stress when the cost of the most expensive and often price-setting technology (natural-gas-fired power plants) suddenly increases, as is currently the case: Natural gas spot prices increased tremendously since Russia invaded Ukraine, peaking at almost 320 €/MWh on August 29, 2022, in the German price zone (Trading Hub Europe). Natural gas future prices were at 270 €/MWh for 2023 and 73 €/MWh for 2026. The minimum electricity day-ahead price on that day was at 516 €/MWh and the peak was at 794 €/MWh. 2023-base-futures were traded at 760 €/MWh and peak-ones at even 1,442 €/MWh. The 2026-futures were at 200 €/MWh and 239 €/MWh, respectively.

However, while the current and future price development for natural gas and electricity shows a slow relaxation, it hints that a pre-crisis level might never reached.[7] For instance, natural gas prices were below 10 €/MWh and electricity prices did not exceed 47 €/MWh on August 22, 2020.

CRISIS SCENARIOS: PRICE RECOVERY OR HIGH PRICES?

Suppose there are two possible developments in the future. In *recovery*, the price for natural gas drops to *pre-pandemic* projected levels (20.20 €/MWh) from 2035 onwards. In *high*, the price remains at twice the level (40.40 €/MWh). Table 1 shows *pre-pandemic* projections and contrasts them with the current developments and with the assumptions from *recovery* and *high*. Observe that prices for hard coal, crude oil, and enriched uranium reach *pre-pandemic* projected levels from 2027 onwards. Lignite prices are indeed unaffected because lignite is not traded. Biomass prices, in turn, are structurally above *pre-pandemic* levels because the general demand for biomass (construction, heating, industry, and electricity generation) increased unexpectedly.

Investment decisions from the *pre-pandemic* case are fixed for the other two scenarios because invest-

[7] Natural gas spot prices dropped since the end of August and were at 100 €/MWh on October 6, 2022. Future prices indeed dropped as well, to 170 €/MWh for 2023 and only 59 €/MWh for 2026. Also, electricity day-ahead prices dropped to 9 €/MWh (minimum) and 360 €/MWh (maximum) for that specific day. Electricity futures cost 438 (base) to 609 (peak) €/MWh for 2023 and only 158 or 203 €/MWh for 2026, respectively. Prices even continued to drop until mid of November.

Table 1

Current and Projected Commodity Prices

Fuel	Scenario	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Biomass	Pre-pandemic	29.1	29.2	29.4	29.5	29.7	29.9	30.0	30.2	30.3	31.5	32.6	33.7	34.9
	Recovery/high	58.2	52.0	45.7	44.9	44.6	44.8	45.0	45.2	45.5	47.2	48.9	50.6	52.3
Hard coal	Pre-pandemic	8.2	8.2	8.2	8.2	8.1	8.1	8.1	8.1	8.0	7.9	7.9	7.8	7.7
	Recovery/high	44.9	32.8	24.5	16.3	12.2	8.1	8.1	8.1	8.0	7.9	7.9	7.8	7.7
Lignite	All	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Natural gas	Pre-pandemic	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
	Recovery	198.5	188.7	120.3	82.9	56.8	40.4	35.3	30.3	25.2	20.2	20.2	20.2	20.2
	High	198.5	188.7	120.3	82.9	56.8	40.4	40.4	40.4	40.4	40.4	40.4	40.4	40.4
Crude oil	Pre-pandemic	41.1	41.2	41.3	41.3	41.4	41.5	41.5	41.6	41.7	42.2	42.7	43.3	43.9
	Recovery/high	61.7	57.7	53.7	49.6	45.5	41.5	41.5	41.6	41.7	42.2	42.7	43.3	43.9
Enriched uranium	Pre-pandemic	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
	Recovery/high	4.9	4.2	3.7	3.3	2.8	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3

Pre-pandemic reflects the projected commodity price developbased on a pre-pandemic sitiation in 2019. Recovery and high reflect true prices in 2022 and deviate only from 2028 onwards for natural gas. All prices are measured in €/MWh. 2022 prices on information gathered on October 6, 2022.
Sources: Tradenomics for current levels; natural gas price development until 2026 from EEX; all other price developments are based on own assumtions.

ment decisions are sticky. Photovoltaic (wind onshore, offshore) investments are fixed until the end of 2022 (2023, 2024). Slight increases are possible in the three following years. For example, Germany can expand photovoltaic capacity by 150 percent of *pre-pandemic* planned expansion plus 5 GW on top of this value in 2023. In 2024 (2025), those values increase to 200 percent (300 percent) and 10 (15) GW. With the same time lags, wind onshore and offshore can be adjusted. The 5, 10, and 15 GW are reference values for Germany and adjusted according to demand shares for the other regions, i.e., countries with lower demand may add less capacity. Intuitively, it is not possible to plan and build a new wind park within five years, but it might be possible to add a couple of wind turbines to already-used or planned locations or even antedate projects. All other technologies are fixed until 2030 because it takes a reasonable number of years to plan, approve, and build power plants. This is particularly severe for nuclear power plants; therefore, all nuclear investments are fixed until 2035.

HIGH PRICE VARIATIONS: NUCLEAR EXTENSION OR STRETCHING OPERATION?

The *high* price scenario seems to be the most reasonable given the current situation. Germany planned to exit nuclear power by the end of 2022, but the current situation brought up political discussions about extending (new fuel rods) or stretching (no new fuel rods) the usage of nuclear power in Germany to reduce electricity prices (and increase grid stability considering the North-South differential). On October 17, 2022, stretching operation of the three still-running German nuclear plants until April 15, 2023 became the official policy. However, an extension of the three still-running German nuclear power plants by 7 years until 2029 is still under discussion.

FURTHER PROBLEMS: MISSING RAIN AND FRENCH NUCLEAR POWER

2022 has been one of the driest years on record, with hydropower generation currently around 10 percent lower than it was in 2020 or 2021, respectively. Moreover, half of the nuclear power plants in France are offline, mainly due to unexpected technical problems. Nuclear power makes up 70 percent of French electricity production and accounts for more than half of the entire European nuclear share. *Pre-pandemic* projections missed these two problems. Real-world data from the OECD about monthly electricity generation by technology is used to calibrate for those effects. Data for the years 2020 and 2021 are available in full, but for 2022 only for January to April. For *pre-pandemic* projections, the average for 2020 and 2021 is used for 2022. For French nuclear power, only 2020 is used because 2021 was already affected by technical problems. For the two crisis scenarios, the monthly availability of those sources is then reduced according to the reduced availability in the first four months of 2022. Altogether, this reduces both nuclear and hydropower availability by more than 10 percent.[8]

MODEL

I use EUREGEN that optimizes dispatch, investment, and decommissioning decisions in 28 countries (EU27 minus Cyprus and Malta plus Norway, Switzerland, and United Kingdom) of the European power market to obtain the cost-minimal technology mix.[9] EUREGEN optimizes years 2020 to 2030 and from 2035 in five-year steps intertemporally, thereby using a less fine-grained hourly resolution per year. European electricity demand is assumed to keep almost constant until 2025 (at around 3,000 TWh) and then more than doubles until 2050 (to 6,200 TWh) due to electrification (heating, mobility, hydrogen production), intensified cooling, digitalization, and economic growth. The other driving force is the EU ETS, including the market stability reserve (MSR), that is adjusted to reflect recent ambitions regarding carbon neutrality by 2045. I link EUREGEN iteratively with a model of the EU ETS that simulates in detail the dynamics of the MSR (Azarova and Mier 2021). I determine industrial emissions within the EU ETS based on a marginal abatement curve in relation to electricity sector emissions for our *pre-pandemic* projection but keep industrial emissions constant for the two crisis scenarios because industrial emissions currently show an adverse behavior to electricity emissions.[10]

RESULTS

Figure 1 shows the technology mix and related CO_2 emissions when taking *pre-pandemic* projections (first bar in each cluster), price *recovery* (second), or *high* prices (third) as given. Observe that the CO_2 emissions

[8] Maintenance intervals of still-running French nuclear power plants were adjusted and usage of the working fleet intensified, so that overall nuclear production in 2022 is projected to drop only from 681 to 655 TWh (all over Europe). This effect covers rebound effects of high natural gas prices. Hydropower generation drops from 559 to 475 TWh.

[9] See Weissbart and Blanford (2019), Mier, Adelowo and Weissbart (2022), and Mier and Adelowo (2022) for the basics of the model; and Mier and Weissbart (2020), and Azarova and Mier (2021) for some applications. Investment cost functions are adjusted according to Mier and Azarova (2021 and 2022). Technological calibration mainly stems from Mier et al. (2020 and 2022) and Siala et al. (2022).

[10] There is much similarity to the study setup in Mier (2022). However, the calibration with OECD data is new, and current as well as future price developments are calibrated to the beginning of October (before beginning of August). Demand projections are adjusted so that electricity demand keeps almost constant until 2025 and starts growing from 2026 onwards. Also, the plans of a stretching operation of nuclear plants were not public before and are thus adjusted in accordance with the findings discussed: January 2023 would be used to prepare reactors for the stretching operation. Old fuel rods would be used so that availability is reduced in January to 75 percent (preparation time and due to aged fuel rods), in February to 80 percent, and in March as well as April to 70 percent of maximum power. The extension works with historical availability patterns of nuclear power plants in Germany and lasts until the end of 2029. Another difference is the detailed modeling of German combined-heat-and-power (CHP) generation to account for must-run natural gas in the system due to heating requirements.

are by far higher in the two crisis scenarios than under *pre-pandemic* projections until 2027. This is because the commodity price situation fosters a shift towards lignite and coal, whereas natural gas usage is reduced. Also, biomass is by far more competitive under the two crisis scenarios, although biomass prices are above *pre-pandemic* projections. CO_2 emissions from the crisis scenarios come close to *pre-pandemic* levels in 2027 and are lower from 2028 (*recovery*) or 2030 (*high*) onwards because the MSR contains fewer allowances that are fed back into the system. However, overall invalidation of allowances is 735 million lower in the *high* scenario, hinting that the current crisis is not only bad for electricity bills but also for the climate.[11] Interestingly, even the *recovery* technology mix deviates slightly from the *pre-pandemic* mix because of substantially higher investments in wind and photovoltaic as long as natural gas prices stay high, so that the entire system needs less gas but more nuclear in the long run.

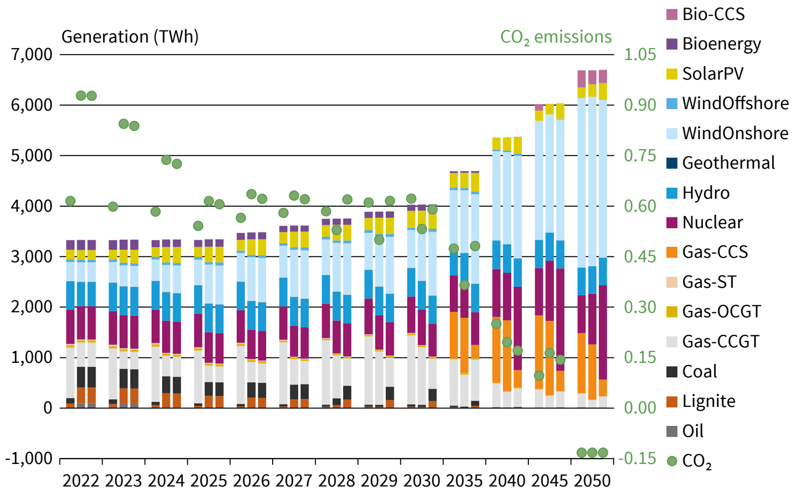
The *high* prices even increase nuclear capacity so that nuclear is used to regionally dominate systems and even partly balance intermittent renewable supply. Shares of gas-fired power plants in combination with carbon capture and storage (Gas-CCS) in turn are by far the lowest. Whether the natural gas price drops to *pre-pandemic* levels or stays at twice that level will decide the future of nuclear power in Europe. The substituting technology would be gas-CCS.

Now let's turn to the electricity prices that result from the different scenario assumptions. Table 2 shows that *pre-pandemic* projections yield European average electricity prices of 65 €/MWh in 2022, increasing slightly until 2030 and then dropping to 62 €/MWh in 2050. Thus, decarbonization of the system (2050 comes with negative CO_2 emissions from electricity generation of -132 Mt that are counterbalanced by 132 Mt of industrial and aviation emissions) and doubled demand increases prices only in the mid-term but not in the long-term due to massive usage of onshore wind and the availability of cheap natural gas in combination with CCS. Natural gas prices remain *high* until 2030 under *recovery* assumptions, resulting in considerably higher prices. However, the long-run price is like the *pre-pandemic* one. In total, early adjustment processes in 2023 to 2026 due to substantially higher natural gas prices finally yield a slightly more expensive system because less gas-CCS is used and substituted by wind and nuclear power. Under *high*, the natural gas price remains high. The price development is like *recovery* until 2027. The long-run equilibrium price is slightly higher than under *recovery* (69 vs. 65 €/MWh).

High imposes a completely different system with structurally higher nuclear and photovoltaic shares.

Figure 1

Technology Mix and Carbon Emissions in the European Electricity Market



Note: This figure shows three scenarios. The pre-pandemic projections (first bar in each cluster), and two crisis scenarios: price recovery (second), or high prices (third). CCS (carbon capture and storage), CCGT (combined cycle gas turbine), ST (steam turbine), OCGT (open cycle gas turbine), and SolarPV (photovoltaics).
Source: Author's calculations.
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The latter stems from early investment in 2023 to 2025, while higher nuclear goes back to the doubling of natural gas prices, so that it is optimal to invest heavily into nuclear power from 2040 onwards.[12]

The German price development is like the European one, but German crisis prices are considerably lower because the system is more diversified and less reliant on natural gas. In the two crisis scenarios, the 2022 price is around 150 €/MWh lower, while the 2023 price is lower still, by 38 €/MWh. Moreover, German prices can be further reduced if operation of the three existing nuclear power plants is extended. The price effect would be -7.31 percent in 2023 and -2.95 percent in 2024. From 2026 to 2029, the price effect drops considerably. Stretching operation reduces prices only in 2023, by 2.98 percent. Moreover, nuclear extension adds around 30 TWh of electricity generation to the German system and substitutes around 3.2 TWh (6.5 TWh) of electricity generation by gas-fired power plants in Germany (Europe) in 2023, reflecting 6.6 TWh (12.9 TWh) less natural gas consumption.[13]

Now let's turn to the effect of the reduced nuclear availability in France and of reduced hydropower generation due to low rainfall in the first half of 2022. The German prices under the *high* scenario would be 2.21 percent lower without both occurrences. European prices would be even lower by 32.3 percent, whereas the single effects are at 15.05 percent (for French nuclear) and 19.66 percent (for hydro). This shows that the currently *high* electricity prices (in Europe) are driven to two thirds by higher commodity prices (mainly natural gas); the last third comes from

[11] The invalidation of allowances finally decides about the climate impact of the crisis and related policy measures. The stretching operation (nuclear extension) increases the invalidation volume by 2.6 (24.8) million allowances and thus the true climate impact is considerably lower (higher) than the 2023 savings.

[12] Countries without nuclear history are not able to build nuclear power plants, same as Germany, but in the latter case due to Germany's nuclear exit. The expansion of nuclear thus comes solely from nuclear-using countries. Non-nuclear countries instead invest in gas-CCS.

[13] Other considerable substitutes are bioenergy, coal, lignite, and photovoltaic. Stretching operation saves 4.8 (6.8) TWh of natural gas consumption in Germany (Europe).

Table 2

Electricity Prices in Europe and Germany

Price	Scenario	2022		2023		Jan-Apr 15		2024		2025		2026		2027		2028		2029		2030	2035	2040	2045	2050
European	Pre-pandemic	65		65		78		69		66		68		70		70		72		86	75	67	65	62
	Recovery	371		253		314		177		118		98		85		86		84		84	75	68	67	65
	High			249		311		171		117		98		82		86		86		85	100	76	74	70
	German nuclear extension until 2029	370		245	−1.79*	305	−1.85*	169	−0.92*	115	−1.12*	97	−1.16*	83	0.28*	85	−0.65*	86	−0.65*	86	101	76	74	69
	German nuclear streching until April 2023			248	0.65*	306	−1.51*	171		117		98		82		86		86		85	100	76	74	70
	Normal French nuclear	322	15.05*	250		312		171		117		98		82		86		86		85	100	76	74	70
	Normal European hydro	309	19.66*	250		313		171		117		98		82		86		86		85	100	76	74	70
	Normal French nuclear and European hydro	208	32.30*	250		312		171		117		98		82		86		86		85	100	76	74	70
German	Pre-pandemic	66		68		80		70		66		67		69		70		72		86	76	72	65	62
	Recovery	226		214		295		161		97		88		79		84		82		83	76	72	69	65
	High			211		293		148		93		88		76		81		84		84	100	84	77	70
	German nuclear extension until 2029	244		195	−7.31*	271	−7.43*	144	−2.95*	91	−3.04*	86	−2.27*	76	0.04*	80	−1.30*	82	−2.10*	86	100	83	77	70
	German nuclear streching until April 2023			204	−2.98*	275	−6.01*	148		93		88		76		81		84		84	100	84	77	70
	Normal French nuclear	223	0.66*	211		293		149		94		88		76		81		84		84	100	84	77	70
	Normal European hydro	220	1.78*	211		294		149		93		88		76		81		84		84	100	84	77	70
	Normal French nuclear and European hydro	219	2.21*	211		294		149		94		88		76		81		84		84	100	84	77	70

* in percent.
Pre-pandemic reflects the projected commodity price develop based on a pre-pandemic situation in 2019 with normal French nuclear availability in 2021 an 2022 as well as normal European hydrpower generation in 2022. Recovery and high reflect true prices with sticky investment planning based on a pre-pandemic situation. High scenario variations calculate changes resulting from nuclear extension (until 2029) or streching (until April 15, 2023) operation. Normal French nuclear and normal European hydro calculate prices under normal French nuclear availability and normal European hydrpower generation.
Source: Authors` calculations.

the unique situation of low hydropower generation and low nuclear generation in France.

POLICY CONCLUSIONS

The European electricity system is under stress because natural gas is essential to ensure reliability of service and satisfy demand. The current answer to this stress still only takes the form of high electricity prices, which are predicted to be six times higher than what they would be without the current natural gas crisis. Germany is better diversified, and price rises are predicted to be less severe. Extending or stretching nuclear usage in Germany would help to bring prices further down, by 7.3 percent or 3 percent in 2023. However, electricity prices are going to drop even without Germany reconsidering its usage of nuclear power as soon as either natural gas prices drop, or the system can adjust through investments to reach a new long-run equilibrium. Investment uncertainty remains high because actors do not know the new equilibrium price of natural gas, which will decide whether Europe is going to be a wind-power-dominated system with gas-CCS as balancing technology, or nuclear becomes an option again.[14]

In reaction to rising prices, policymakers have suggested subsidizing natural gas prices and are discussing capping revenues from high electricity prices for "inframarginal" producers, i.e., those that do not rely on gas (such as renewables, nuclear, and lignite). The European Commission has suggested such a revenue cap.[15] While it would not reduce electricity prices in the short run, because the resulting market price would remain unchanged, it would reduce the "margins" for all "inframarginal" generators to a socially acceptable level. Let us assume that those non-inframarginal generators cover only power plants burning natural gas and suppose the market clearing price is 400 €/MWh. Gas-fired power plants would receive the 400 €/MWh. All other power plants would only receive 180 €/MWh, and the 220 €/MWh gap would be a kind of tax that flows to the government budget and can be used to finance relief packages. Again, the revenue cap would not reduce the bills to final consumers. However, it might play a part in the relief packages to do so.

These changes are theoretically sound. However, when looking into the details trouble starts. For example, a great deal of electricity in Germany is traded over-the-counter (OTC) and thus not exchanged in the spot market. OTC contracts are bilateral, often long-run, delivery obligations. Suppose that generator A and consumer B have such an OTC contract for 2023 promising that A delivers a certain amount of electricity to B at price 300 €/MWh. B is unaffected by the proposed revenue cap and pays 300 €/MWh. How much of those 300 €/MWh stays in A's pocket? This question cannot be easily addressed. Suppose that A generates electricity with gas-fired plants, but also with coal, lignite, nuclear, and renewable energies. How much of each technology is A using to satisfy the contract with B? The situation becomes more complex when A is active on the spot market in parallel. Moreover, the contract is already a portfolio decision and

[14] Nuclear investment cost used are around 6,000 €/kW and social costs stemming from decommissioning or waste disposal are more or less ignored, as was historically the case.

[15] https://ec.europa.eu/commission/presscorner/detail/en/IP_22_5489.

thus A might run into significant trouble in the face of a revenue cap. If all electricity were traded in spot markets and bids were technology-specific, the situation would be less complex, but this is not the case.[16]

On top of the OTC contracts, there are financial assets traded (so-called futures) ensuring a certain price for A. Suppose A bought such a future that ensures him to obtain 600 €/MWh for all electricity produced in 2023. Is such financial contract affected by the revenue cap? If it is, then A would first need to give away 220 €/MWh (400 – 180) from the physical market and then 200 €/MWh or even 400 €/MWh from the financial one? Again, the portfolio of technologies used is not clear because A signed the contract for its entire portfolio.

There is further trouble stemming from such a revenue cap. The definition of "inframarginal" is spongy and contextual. When looking at prices of generators, then power plants burning biomass and oil are also close or even above the mentioned 180 €/MWh, as are combined-heat-and-power plants using biomass, oil, and gas. Coal indeed is below the 180 €/MWh, but in fact often a marginal, i.e., price-setting technology.[17] The role of coal is very important. Should regulators allow massive profits for coal or not? Does this reflect our ambitions to reduce carbon emissions? In the end, much ideology is put into market design by such a revenue cap, while technologies are not treated equally, leading to windfall profits for the lucky ones with the most suitable generation and contract portfolio (OTC, futures). However, the revenue cap would not hamper security of supply, because the margins in the market stay positive, so that providing generation is the best option for each firm in the market. Also, investments are sticky, so that short-term changes in profits do not change the long-term investment incentives no matter whether such revenue cap applies or not. Finally, such a revenue cap would only apply for clean technologies (wind, solar, hydro, nuclear) and lignite as the dirtiest one. But lignite availability is very regional and thus the relevance for the whole of Europe is reduced. Moreover, many of European systems are natural gas-driven and thus a revenue cap would also raise little money, while increasing uncertainty in the market.

Among the possible solutions is to slap a windfall tax on generators to reduce their excess profits. The idea is to allow for a reasonable return-on-investment (ROI), but then tax the profits that exceed such a reasonable ROI – albeit at rates below 100 percent, so as to keep incentives to invest and maximize profits. Suppose that the historical ROI of an electricity generating company is 10 percent. The regulator might allow 20 percent ROI during this crisis, but all profits above this 20 percent would be taxed at a rate of 90 percent. Assume that a big company usually makes profits of €1.5 billion (reflecting a 10 percent ROI), but its 2022 profits hit €10 billion. Of this, €3 billion would be allowed under the "up to 20 percent ROI" rule, and the remaining €7 billion would be taxed at 90 percent, leading to a €6.3 billion contribution to the government budget. €700 million of the excess profit would remain with the company, for a final overall profit of €3.7 billion.

The advantage of such a windfall tax lies in the equal treatment of technologies, thus being less erratic than would be the case under the uncertain definition of "inframarginal" in revenue cap regulation. Focusing on excess profits would also account for the fact that some companies are just lucky due to long-term-delivery natural gas contracts, meaning that the price they currently need to pay for natural gas is below the market price. Such excess profit regulation comes with lots of work, and money lands in governments' coffers with time lags, but public refinancing via debt was not problematic in the last decade. Furthermore, electricity generation is dominated by big companies that can easily shoulder the burden of additional information provision when doing their tax declarations. Such a windfall tax scheme would also entail an additional burden for public authorities, but European society has been in crisis for more than 2.5 years, with certain groups of professionals – nurses, doctors, intensive-care personnel and so on – being asked to devote more time and effort than usual. The difference now would be that officials engaged in regulating electricity supply would be among those asked to dedicate extra work to reduce cost to a socially acceptable level.

While none of the suggested electricity market changes would directly reduce electricity prices – because neither supply would be increased nor demand reduced by such changes – they would indeed contribute to the fiscal purse at times of greatly expanded outlays.

[16] Indeed, bid-based system as applied in Northern America would be far more suitable, because more information is collected, and the market clearing is more centralized.

[17] Actually, intermittent renewables such as hydro, wind, and solar are also often marginal.

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