Abstract

North Rhein-Westphalia is forecast to soon experience electricity demand growth not seen since reconstruction after the Second World War. Investments in grid infrastructure of commensurate scale will be necessary, but in order to enable a rapid, cost-effective expansion and decarbonization of a comparatively laggard, dirty grid in NRW, several national reforms are necessary. Germany's single bidding zone must be divided to create accurate local price signals, which will reduce system costs and engage supply- and demand-side distributed resources. Distribution companies need to be given consistent engineering-based revenue caps while being exposed to risk on their investments to avoid waste and bureaucratic slowdown. Lastly, demand response and aggregation must mature into a powerful tool to mitigate peak loads which drive costs and carbon emissions, which will require legal recognition of its place in the competitive electricity market and supportive tariff reform.

Background

The state (*Bundesland)* of North Rhine-Westphalia (abbreviated NRW) is located in western Germany. It is densely urban, home to the cities of Dortmund, Essen, Duisburg, Cologne, and Bonn, historical and present-day centers of industry in Germany, and over 18 million inhabitants. NRW is entirely contained in the "Amprion" control area, Amprion being the single private utility that (solely) owns and operates the transmission network in the state as well as the neighboring state of Rhineland-Palatinate, which borders France and the French electricity market.

National climate legislation has driven long-term renewables development in Germany; the Renewable Energy Sources Law requires preferential dispatch of renewable energy, and draws funds from the federal budget to contract renewable energy projects. Recently revised to be even more ambitious, the law sets a target of achieving 80% renewables penetration by 2030 - nationally in 2023, renewables penetration was around 58%.[1] NRW, however, is well behind the rest of the country, achieving renewables penetration of only 20-25% in recent years.[2]

The Amprion regional grid expansion plan forecasts a 205 TWh/yr increase in demand in North Rhein-Westphalia, a more-than-doubling of current annual load. Supply growth will be more than 100 GW of growth in wind, solar, and battery capacity.[3] The Bundesnetzagentur (Federal Network Agency - henceforth BNetzA) found that Westnetz alone, by far the largest distribution utility in NRW, had planned nearly €20 billion in grid expansion by 2045 while Amprion has planned more than €36 billion in transmission expansion by 2029.[4,5]

Diagnosis

Distribution Regulation

Under the Energiewirtschaftsgesetz (Energy Industry Act; henceforth EnWG), distribution companies are regulated by state or federal energy authorities depending on their number of connected customers. The relevant energy authority is responsible, every five years, for setting the annual revenue caps for each distribution company for the following five year regulatory period. The calculation of these revenue caps is based on cost breakdowns distinguishing “efficient” and “inefficient” expenditures; the revenue cap formula contains an adjustment by the producer price index, a adjustment that reflects an expectation of reducing inefficient expenditures over the regulatory period, a (downward) adjustment by a national productivity factor, and a guaranteed return on capital investments. Distribution companies can receive a quality bonus or malus to their revenue cap proportional to their out- or underperformance of the national average System Average Interruption Duration Index. For this bonus/malus to take effect, its magnitude must be at least 2% of the revenue cap, while any larger magnitudes are flattened to 4% of the cap.

These regulations, designed during an era of stable or declining load, are not well suited to the coming period of sustained, rapid load growth in NRW. To meet demand, distribution companies will need to be regularly making sizable capital investments. The guaranteed return on capital would appear to robustly account for these investments in the revenue cap. However, in response to industry complaints that the energy transition wasn’t accounted for in determining this guaranteed rate of return, the BNetzA asserted that transmission expansion planning and publication requirements void any additional uncertainty created by the energy transition but did not address distribution. Indeed, three quarters of distribution companies in the Amprion area are not obligated to create or publish network expansion plans.[6] The BNetzA was also dismissive of other “erratically occurring complexities” due to the energy transition as being better treated by its other more precise regulatory instruments.[7] It is noteworthy that the revenue cap adjustment for new investments in the midst of a regulatory period must actually be requested by the distribution company and reviewed for operational necessity by the energy authority, which imposes an impractical bureaucratic burden given the quantity of new investments that will certainly be made. The other significant tool that adjusts revenue caps within a regulatory period is the so-called “extension factor,” which kicks in when a distribution company’s effective area, number of connection points, or annual load changes by enough to affect their total “efficient” costs by more than half a percent. Given the imminence of rapid load growth across NRW, this will soon be the case for countless distribution companies. These two mechanisms beg a more elegant regulatory solution for periods of growth which can enable rapid cost-effective network expansion by more closely adhering to the principles of a revenue cap.

Transmission Regulation

Transmission utilities, while legally distinct from distribution utilities under German law, are not strongly distinguished from those distribution utilities for the purposes of many regulations, which apply to *all* “network operators.” Consequently, Amprion, NRW’s sole transmission utility, regulated by the BNetzA, operates under fundamentally the same revenue cap structure described by the previous section for distribution companies.

Of course, Amprion’s investments are much larger and subject to much more scrutiny by the BNetzA than any distribution company’s. Every two years, Amprion and the other German transmission utilities must collaborate on a “scenario framework,” which is advised and then submitted to the BNetzA for approval. Within ten months of this approval, they must publish a draft of a national network development plan, working (amongst themselves) from the European Ten Year Network Development Program and the identified scenarios from their framework. In years without a new network development program, transmission utilities issue an implementation report on their progress realizing the development plan that year.

Contemporary legislative and regulatory interventions in transmission planning have meaningfully acknowledged the need for transmission expansion and laid the legal groundwork for future transmission reforms. The 2009 Energy Line Expansion law listed specific contemporary high-voltage (380 kV) transmission projects with a “overriding public interest” whose approval process could be streamlined; similarly, in 2011 the Federal Need Plan law explicitly listed a number of more diverse transmission projects essential to integrating renewable energy, shuttering nuclear power, and ensuring interoperability with the European grid. Most recently, a 2019 revision of the other 2011 Network Expansion Acceleration law created a number of exemptions for the federal approval process for transnational and trans-state transmission projects under specific circumstances. While this whack-a-mole uneven approach to streamlining the planning process has kept bureaucratic obstacles from greatly slowing transmission expansion as is commonplace across the United States, it has never approached comprehensive reform, though the legal principle of overriding public interest behind specific projects is promising for future refinements of the planning and approval process.

Wholesale Electricity Generation, System Operation, and Security of Supply

As mentioned, North Rhein-Westphalia is served wholly by Amprion, which is one of four transmission operators in Germany. Amprion is one of many relatively integrated European transmission utilities, each of which must constantly balance supply and demand within their "control area." The initial dispatch order of generators is determined by the clearing price on purely financial day-ahead and intraday markets, but this is where the problems begin. Germany, despite containing four control areas, forms a single bidding zone, which means generators and consumers from across the country are trading with one another. Those financial markets do not, however, account for congestion or losses, i.e. the physical realities of transmission infrastructure. For instance, zero-marginal-cost offshore wind dispatches immediately from the Baltic sea to meet demand in Passau at the Austrian border when the infrastructure does not exist to support that power flow, even though generator and consumer were able to complete the same trade financially in the day-ahead market.

Such would be the issue in any bidding zone as large and with as diverse generation and consumption geographies as Germany. But the problem is compounded by the several control areas which are each obligated to balance supply and demand in a real-time market. Their ability to do this by trading with other nations is limited, since cross-zonal flows are scheduled in the day-ahead market (following the German national spot price, which has nothing to do with reality) and stringently upheld even when redispatching. Thus cheap, clean generators in the north are paid in addition to the spot price to curtail their production while expensive, dirty generators in the south and west are also paid more than the spot price to come online. Consequently, the German transmission operators pass on an immense sum in redispatching costs to consumers. In 2023, Amprion incurred redispatching costs of €500 million, approximately 10% of their total revenue that year! And this, astonishingly, represented a decrease in redispatching costs relative to 2022, though even that fact is misleading. Amprion saw lower redispatching costs in 2023 purely because of a lower average wholesale price of electricity, when redispatching volume nearly doubled between 2022 and 2023.[8] Though congestion management contributes much less to redispatching costs nationwide, congestion is concentrated in the northwest in lines that directly or indirectly transmit off-shore wind power (from the TenneT transmission utility) to NRW (under Amprion).[9]

There have, however, been recent positive developments in integrating European reserve markets initiated by the EU Electricity Balancing Guideline. PICASSO, MARI, TERRE, and the FCR cooperation all seek to reduce balancing costs by integrating automatic frequency restoration reserves, manual frequency restoration reserves, “replacement reserves” (which do not exist in Germany), and frequency containment reserves markets, respectively. Lastly, the IGCC seeks to facilitate spontaneous cross-zonal power trades when it would efficiently balance both parties’ areas, further reducing costs. Each of these measures have achieved various levels of adoption among European countries. Amprion hosts the MARI platform, which is estimated to have saved €8.5 million in system balancing costs in 2023.[10]

Retail Rate Design and Retail Competition

The retail market for electricity in NRW is highly competitive, as it is in much of Germany. Voluntary retailer-switching has risen continually in Germany for over a decade, signalling fierce competition for customers.[11] While there is scant public state-level data on retail competition, there are exciting developments at the national level which are grounds for optimism about German retail rate design - and potentially flexible demand. The federal New Beginning for the Digitalization of the Energy Transition law, passed in 2023, mandated that retail electricity providers with more than 100,000 customers offer at least one dynamic tariff to end consumers with smart meters and flexible demand capacity. That law, incidentally, also provides for the necessary infrastructure for demand response, as it sets targets to equip 95% of households with smart meters by 2032. At present, 7% of households pay a dynamic tariff, which is more than triple the proportion using dynamic rates in 2022. More than 60% of households are open to switching to a dynamic tariff, supposing it would reduce their energy bills, though a vast majority feels ill-informed about these tariffs.[12]

The traditional German tariff is fully hedged for the customer, who makes a fixed monthly payment and receives a fixed volumetric rate. Though the EnWG does not prescribe or restrict how dynamic tariffs should function, “dynamic rates” that impose some small monthly or annual fixed cost and then pass through the electricity clearing price in the German bidding zone predominate. These rates arguably don’t capture the full breadth of consumer desires - most households declare a preference for some kind of price hedge, even if it would reduce their cost savings from a dynamic rate.[13] There are also a number of simpler regimes which offer a “high” and a “low”/”night” tariff, which target customers with heat pumps, while there is an even older, more popular retail market where consumers voluntarily pay higher rates to buy exclusively clean energy; 54% of retail electricity sold to German households in 2023 was packaged in such an “eco-electricity” rate, up from 26% in 2018.[14] Intense retail competition is yet to fully realize the potential value of cost-reflective dynamic tariffs, but the continued vitality of the retail market and the success of companies offering increasingly tailored rates, like Octopus Energy, suggest that they’re well positioned to do just that.

Reforms

Local Pricing

As outlined in the section on wholesale markets, the singular national wholesale price imposed by Germany's market structure is distortionary and creates wasteful redispatching expenditure. Further, leading German energy economists have pointed out that distributed energy resources - generation, storage, and demand response - will necessarily orient their behaviour on the wholesale price of electricity as a guiding signal and cannot be redispatched by the transmission utility, while a forced national spot price also prevents the collection of the economic, social, and political benefits of expanding clean energy.[15] A success story of rolling out smart meters, local storage, and demand-responsive infrastructure might be neutralized or even net negative for the grid if those technologies are bound to obey an inaccurate price signal. Meanwhile political movements are coalescing around attacking renewables for "increasing energy prices," and there is a significant opportunity cost incurred by not creating local regions with cheap energy, especially in light of the need to advance energy-intensive domestic hydrogen production and other frontiers of green industry. This is a broken system in need of reform if the energy transition is to succeed.

Those energy economists advocate, as does this document, a system of local electricity prices to restore the incentives created by wholesale markets. Locational marginal prices are the platonic ideal of local electricity pricing; they are calculated at any point in a region to reflect the marginal cost of consuming electricity at that point including grid losses and congestion. Indeed, a robust system of LMPs could be especially effective at engaging distributed energy resources to alleviate even extremely local strains on the grid. However, it is difficult to imagine rallying the political support, building the legislative momentum, and creating the physical & digital infrastructures necessary to implement such a system across Europe in the short to medium term, which is the timescale on which reform is necessary to meet Germany's environmental commitments. It would be similarly impossible to enact such a system only in Germany while maintaining current levels of integration with the European market, and abandoning European market integration is unthinkable for long-term decarbonization.

Instead, looking to the examples of Norway, Sweden, and Italy, which each have a single national control zone to balance but several subnational bidding zones with independent spot prices, a natural solution would be to divide Germany into several bidding zones. The existing control areas make for an attractive proposal: four independent spot prices for four balanced regions. Policymakers may not have another choice: it would be structurally impossible to operate a bidding zone across several control areas, since in European markets a bidding zone is the largest area in which bidders do not require capacity allocations (between control areas). A long-shot but fundamentally reasonable proposal is to eliminate the archaic exclaves and other oddities of the current division of the country into control areas. Either by agreement, incentive, or coercion, the four German transmission operators could be made to swap assets such that they each became single, contiguous regions. There would be serious one-time costs associated with this adjustment, but also serious potential upsides. Instead of being restricted to four bidding zones, each control area could host several. There could be a bidding zone for every Bundesland, though finer divisions into more balancing zones will be limited by the scheduling of rigid cross-zonal exchanges.

A key advantage of this proposal is that there are formal, defined EU procedures to divide one bidding zone into several. Indeed, the Austrian bidding zone today exists as it was segmented from the former Germany-Luxembourg-Austria bidding zone. In fact, extremely recent bidding zone studies have examined this very proposal, forecasting economic gains on the order of €250-400 million from splitting Germany into four bidding zones.[16] The recommendation, however, has been summarily rejected by Germany's governing conservatives and opposed by influential industrial groups.[17] It is a fair criticism to point out that not every region is a winner under this policy. Industrial regions in the south and west, including NRW, would likely face immediate higher electricity prices. A policy to ease the transition to such a system could take the form of temporarily subsidizing locally risen industrial and/or household electricity prices using the budget room created by falling redispatching costs. It is fundamentally necessary, however, to create these accurate price signals, even when they bite, in order to accelerate and effectively engage distributed resources, fix international power trades, and to reduce system costs through efficient dispatching.

Forward-Looking Distribution Remuneration - Reference Network Models

The current regulation of revenue caps for distribution companies is outmoded for a period of unprecedentedly rapid grid expansion. The current formula attempts to account for major shifts in the demand landscape through an "extension factor" which takes effect only when these shifts increase the "efficient" share of total costs by more than half a percent within a regulatory period. Given the consensus among forecasts that demand and distributed resources will both dramatically increase until 2045, this band-aid addendum on the revenue cap that simply multiplies it by a factor proportional to load, connection point, or area growth, will not create responsible revenue limits for distribution companies when both the boldness and efficiency of the buildout are essential. Nor will a guaranteed return on investment create those caps; it would be less objectionable if these investments could actually be verified for their operational necessity, but the coming frenzy in distribution expansion will mean either bureaucratic quicksand and delay as capital return adjustments requests pile up for proofing, or that these verifications will be swift but mostly rubber-stamp, guaranteeing return at the ratepayer's expense on all kinds of investments may or may not be operationally necessary. Neither of these outcomes are desirable.

Clearly, these two terms in the formula were meant to allow for moderate growth and investment during the relative tranquility of the electricity sector following liberalization, but they can no longer be the primary way distribution companies are allowed to expand within a regulatory period. To set responsible revenue caps for distribution companies which remain unmodified in most cases for the entire duration of a regulatory period, realities of evolving demand need to be seriously incorporated into calculations instead of being a tack-on. This document proposes incorporating an engineering-based reference network model (RNM), which utilizes cost and consumer data to find least-cost grid expansion pathways subject to quality-of-service regulation, into the formula for distribution companies' revenue cap.

A limitation of all these models, no matter how detailed, is that they will produce revenue caps that are systematically insufficient for real distribution companies to operate under. They cannot account for the risks and realities of building actual infrastructure, including bureaucracy, local opposition, or (ironically) environmental protections. Instead, taking inspiration from Spain's revenue cap formula,[18] the most recent, pre-reform, revenue cap can be taken as a base value, which for each year in the regulatory period is adjusted upwards by the producer price index and then modified by the RNM's identified change in remuneration due to growth in demand, distributed resource activity, or changed quality of service. This is merely an example of one such formula to illustrate the central regulatory proposal, which is to have revenue caps increase according to the results of RNM's least-cost analyses, though not set by them directly.

This change would involve abolishing both the extension factor and the guaranteed return on investment for distribution companies, which would constitute a major doctrinal shift in remuneration regulation. The tradeoff is between implicitly endorsing some backdoor wasteful investments by distribution companies seeking to widen their margins during a construction boom or increasing distribution companies' risk exposure, and thus their cost of capital, which is not to take lightly given the scale of the private funds which need to be mobilized for the energy transition. Policymakers shouldn't, in their attempts to eliminate wasteful investments made with ratepayer dollars, increase the cost of capital so much for distribution companies that ratepayers end up bearing higher costs anyway. One way to fine-tune this tradeoff is to inflate the

RNM adjustment term by some calibrated factor greater than one. This offers distribution utilities the prospect, if they can sustainably carry out near-optimal least-cost investments, of "outperforming" their rate cap and reaping increasing their collected profit each year. This would need to be especially finely-tuned, for if it were too generous over a long period, ratepayers just would end up paying for distribution companies' exorbitant profits year after year as their revenue cap outpaced their actual investments.

Unlocking Demand Response

Hours of peak load on the grid are antagonistic to cost-effective grid expansion and decarbonization; they're the periods of dirtiest and most expensive generation, while transmission and distribution investments are scaled to be able to handle peak loads, so they drive network costs as well. As described above, an essential first step to integrate distributed demand response into the grid is to create accurate, local price signals to guide their response behaviour. However, there are larger, more structural barriers preventing the adoption of demand response which must be addressed in order for the network to benefit from demand response in the long term.

This document endorses several regulatory interventions proposed in a report by the Agency for Coordination of European Regulators on continental barriers to demand response adoption and integration.[19] A legal framework for Germany that explicitly acknowledges and defines so-called "active" (i.e. demand-responsive) consumers and aggregators is fundamental to creating the policy certainty needed for demand response to profitably interact with electricity markets. Without this legal recognition, which EU member states were instructed to implement by the 2019 electricity directive, it is difficult to imagine demand response ever evolving into a coordinated, nationally significant grid resource. For example, one facet of the present-day *de facto* exclusion of demand response from market participation is the withholding of final customer data from would-be demand aggregators, though this data is essential to their business model and already accessible to other generating parties. This unequal treatment is blatantly counter to regulators' responsibility to create non-discriminatory electricity markets and to ensure the long-term security of those markets. Demand aggregators must be granted access to this data, removing a key barrier to their entry into the market. Lastly, in keeping with the principles of cost-reflective rate design, Germany must differentiate active and inactive customer tariffs. As time goes on, the disparity in the burden the two categories place on grid infrastructure will only increase, and creating tariffs that reflect that disparity will provide powerful consumer incentives to become active in managing demand, which will benefit the entire network.

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