The Challenging Path to Decarbonizing Southeast Europe's Power Sector

A Massive Transition

By the United States Energy Association's
Elliot Roseman

The massive transition taking place in the power sector of southeast Europe is both unique to the region, and full of lessons for the rest of the world.

It's no secret that Europe intends to rapidly decarbonize the power sector. Many countries and utilities across southeast Europe – whether in the European Union or not – are developing national climate plans and actions to sharply reduce emissions, chiefly using two pillars: retiring existing lignite and coal generation plants and adding substantial renewables.

At the same time, they plan to consolidate (couple) and organize their markets to trade power seamlessly across borders, achieving benefits in both generation and transmission, and providing liquidity and clear price signals to potential investors.

Given this tsunami of changes, it's vital to anticipate and prepare for the opportunities and speedbumps in advance.

To enable stakeholders to do so, the United States Energy Association, in cooperation with the members of our Electricity Market Initiative and the United States Agency for International Development, recently completed an in-depth analysis of the market and network impacts of these changes, regionally and for eleven individual countries, by 2030.

See Figure 1.

Our analysis was comprehensive. To evaluate the prospects for change, this work developed important inputs about projected fossil retirements, carbon prices, renewables development, and hydro availability.

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While the results are revealing – and even surprising – the important takeaways are the operational, regulatory, and policy implications of this dramatic shift in the landscape for electricity and fuels, as well as the prospects for private investment.

We found that these changes will have a huge knock-on effect, and raise vital issues that need to be addressed, including:

Southeast Europe (and each country's) ability to actually implement such vast changes in generation; Whether the new level of carbon dioxide emissions is acceptable; How to deal with the likely increase in wholesale power prices; The need for new grid investment for stability and reliability; and The acceptable level of future electricity imports.

There are six key findings of this analysis, and each poses challenges, as follows:

First, renewables, particularly solar and wind, will play a crucial role in the generation mix, and in reducing emissions, and should be fully encouraged. Figure 2 shows that these eleven countries plan to vastly increase renewables by 2030, from about twelve gigawatts to nearly forty-two gigawatts. This is many gigawatts higher than their plans just a few years ago.

See Figure 2.

However, even at these levels, renewables cannot fill the gap in power supply from anticipated fossil retirements, due to their intermittency and low-capacity factors.

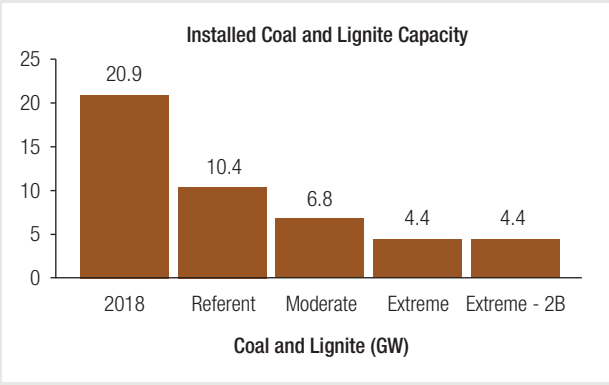
While such ambitious goals are laudable,

FIG. 1 THE EMI COUNTRIES AND MEMBER COMPANIES

Fig. 2 **SEE Plans Huge Increases in Renewables by 2030**

Solar Capacity (Current)	New Solar Expected	Wind Capacity (Current)	New Wind Expected	Total by 2030
7,017 MW	14,175 MW	5,147 MW	15,305 MW	41,544 MW

Fig. 3A **Capacity (GW) From Coal And Lignite Falls Sharply As Natural Gas Rises By 2030**



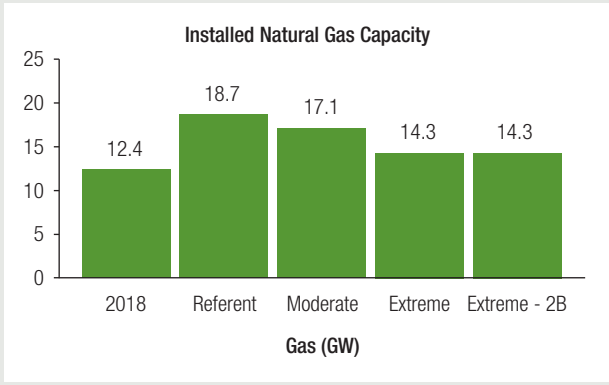
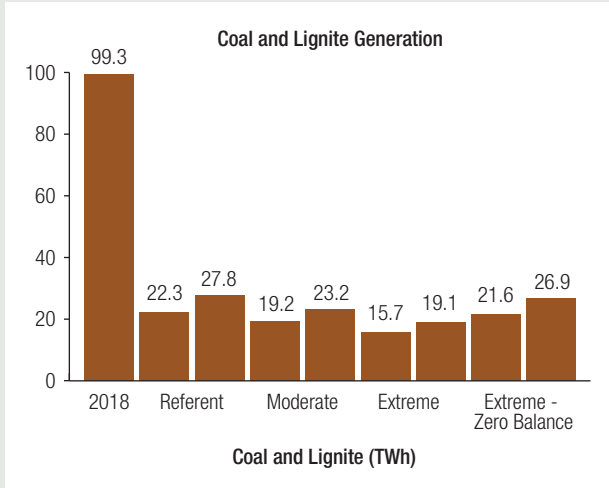
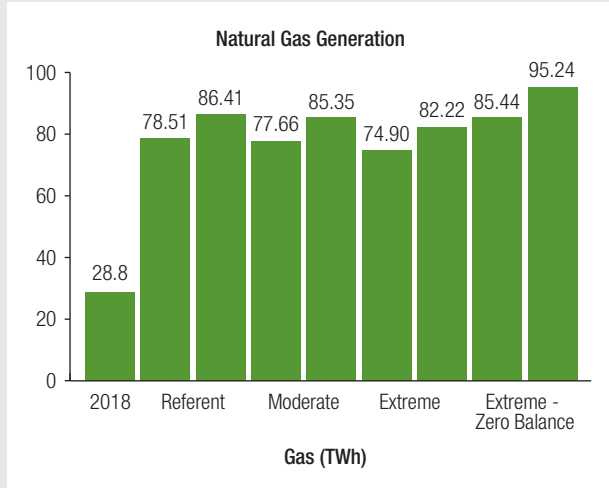


Fig. 3B **Energy (TWh) From Coal And Lignite Trades Position With Gas By 2030**





these renewables will not come about automatically. Many countries need to reform incentive measures; rationalize the interconnection queues; ensure positive regulatory and permitting procedures; and provide favorable investment climates before this capacity will materialize. All this is feasible but will not be easy.

Second, to substantially eliminate lignite and coal by 2030, will require substantial new natural gas generation to keep the lights on. Recognizing this, the countries in southeast Europe already have nine gigawatts of such generation in their resource plans. Other options, such as renewables, storage, hydrogen, and demand-side resources, while certainly desirable, cannot fill the gap from the reduction of coal and lignite generation by then.

We analyzed several scenarios (reference, moderate, and extreme) that greatly reduced lignite and coal capacity. Figure 3A shows that these options started with 20.9 gigawatts today and dropped to 4.4 gigawatts in 2030 (reductions of fifty-five percent to eighty-five percent from today's capacity).

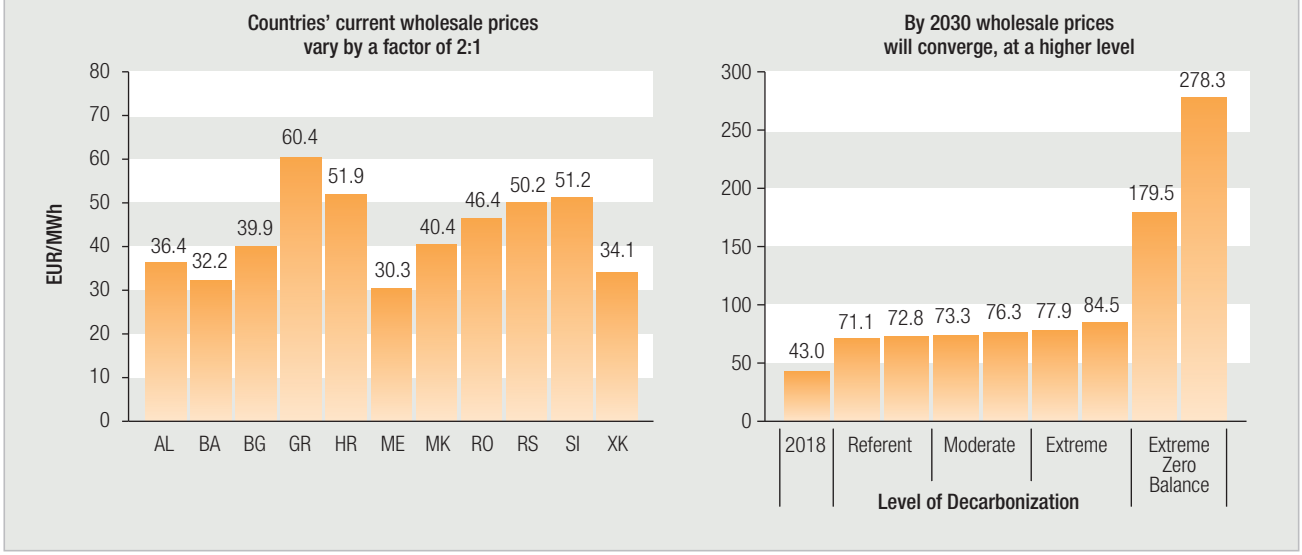
Natural gas capacity does not increase quite as much during this period, since we are also retiring older inefficient gas plants, but as we'll see in a moment, the new gas generation will be highly utilized.

Shifting to energy needs, the brown bars in Figure 3B show that coal and lignite generation will drop precipitously from today to 2030 under these scenarios, from 99.3 terawatt-hours to less than thirty terawatt-hours in all cases (it is also affected by carbon taxes). In every case, the added gigawatt-hour from gas almost exactly mirrors the decrease in lignite and coal.

So, gas generation must be the bridge to a decarbonized future. See Figure 3A.

A key question then is where will all the new gas come from?

Fig. 4 **SEE Can Expect Significant Wholesale Price Increases (Euros/MWh)**



This shift will also require substantial, regional gas-electric coordination, and must rely on truly diverse gas sources so that no single supplier can jeopardize security. This further requires major investments in liquified natural gas and pipeline systems, providing an opportunity for those willing to step in.

Third, these countries need to mobilize considerable capital, within the next several years, largely from the private sector, for this shift to occur. The days of governments owning new wholesale generation are waning. USEA estimates that the region will require fifty billion dollars or more by 2030 to bring the new required gas, renewables, and hydro generation online.

Will bringing in such financing to support this massive shift be challenging? Yes. While one-off projects in southeast Europe are possible, attracting all the equity and debt needed will require the conditions mentioned above, plus, a competitive, liquid wholesale energy market, one integrated regionally at first, and then with the rest of Europe. This is another heavy lift.

Fourth, there will be considerable increases in wholesale electricity prices by 2030 in southeast Europe as markets integrate, and all countries adopt carbon dioxide pricing through the European Union's Emissions Trading System or the fledgling Cross-Border Adjustment Mechanism.

See Figure 3B.

Figure 4 shows that recent wholesale prices in these countries differ by a factor of two, and that some could more than double by 2030. Further, within our scenarios, prices vary by another fifteen percent, largely because higher levels of lignite and coal retirements requires more use of natural gas, at higher prices. Finally, the bars on the far right show how costs could skyrocket if there is a shortfall in regional trade (zero balance). Sustained prices at that level would be a disaster.

See Figure 4.

Renewables cannot fill the gap in power supply from anticipated fossil retirements, due to their intermittency and low-capacity factors.

Such price increases may well pose regulatory challenges and raise questions about government subsidies and could cause social unrest. We only need to look at recent protests in France and Kazakhstan for examples of turmoil when energy prices rise. Government policymakers and national regulators should anticipate these price changes and adopt measures to ensure a

Fig. 5 The Drop in CO_2 Emissions is Less than for Existing Coal and Lignite Capacity

Year 2018	Year 2030					
	Reference Case		Moderate Case		Extreme Case	
	Average Hydro	Dry Hydro	Average Hydro	Dry Hydro	Average Hydro	Dry Hydro
106.1 M Tons (MT)	49.3 MT	57.6 MT	46.5 MT	53.5 MT	42.5 MT	49.1 MT
Fall From 2018 (%)	53.5%	45.7%	56.2%	49.6%	60.0%	53.7%

just transition, particularly for vulnerable populations.

Fifth, the percentage drop in carbon dioxide emissions will be less than for coal and lignite capacity. Even with aggressive renewables, emissions will fall sixty percent or less by 2030 because the remaining coal and lignite plants and new gas capacity must operate at high-capacity factors.

See Figure 5.

While this pace may not satisfy all, it does not preclude major emissions reductions in decades to follow.

Sixth, even with massive generation additions, electricity imports will rise considerably, raising key policy issues. The region can go from relative balance today to importing up to seven percent of its needs; however, some countries' imports could rise to fifty percent or more, and policymakers should decide whether such import-dependence is acceptable to achieve market integration and high levels of decarbonization.

Moreover, it is unclear if neighboring countries will always have enough power to export to southeast Europe if they are also undergoing similar transitions. If such shortfalls arise, reliability could fall, power prices could rise untenably (see Figure 4) and attempts to further decarbonize could unravel.

This finding supports the need for several actions: in-depth system adequacy and flexibility studies (such as strong contingency planning) in each country to raise decision makers' confidence that power supplies will be secure; efforts to foster a regional energy and capacity market in southeast Europe; and wider geographic market integration.

To achieve net zero emissions by mid-century, stakeholders in southeast Europe and beyond should utilize these findings to support market integration and anticipate the impacts of deep decarbonization now.

Fortunately, the regional grid can handle all these changes, and remain reliable, with few bottlenecks that transmission owners and operators can well accommodate by 2030. This testifies to the strength of existing interties; strong transmission planning; and market integration that will raise cross-border transfer capacity.

In sum, these simultaneous changes will be challenging, and require proactive measures well before 2030. To achieve net zero emissions by mid-century, stakeholders in southeast Europe and beyond should utilize these findings to support market integration and anticipate the impacts of deep decarbonization now.

Government utilities and market operators should collaborate with regulators, policymakers, private investors, and others on potential solutions to ensure that the path to a clean and reliable electricity future is a smooth one for each country in the Electricity Market Initiative. USAID and USEA are in a strong position to continue supporting those efforts. PUF

The average American has never spent such a small share of their total expenditures on electricity as in 2021. This according to the most representative and credible data on what goods and services American households spend money on.

Just 1.28 percent of American consumer expenditures in 2021 went to pay electric bills. In all the years since 1959, when the Bureau of Economic Analysis of the U.S. Commerce Department first reported detailed consumer expenditure stats, this percentage has never been this low.

The second lowest year was 2019, the year before the pandemic. That year, the percentage was 1.29 percent.

Electricity's percentage had never fallen to 1.4 percent, let alone below 1.4, until 2016. Yet, in 2016, and in each year since, the percentage has been below 1.4 percent. For the last six years, the percentage has consistently been in the 1.3s or 1.2s. As recently as 2013 and 2014, the percentage was significantly higher, at 1.49 percent.

When was electricity's percentage of consumer expenditures the highest? In 1982. That year, the percentage was 2.27 percent. That's just about a full percent above the 2021 number. Indeed, during the entire twenty-three-year period of 1974 through 1996, electricity's percentage was always 1.73 percent or higher.

As recently as the four great recession years of 2008 through 2011, electricity's percentage was 1.55 percent, 1.59 percent, 1.63 percent, and 1.56 percent. That's more than a quarter of a percent above the 2021 number.