The Coalition of Finance Ministers for Climate Action

The impact of uncertainty surrounding energy transition paths: tools for Ministries of Finance and investors to manage the financial risk of infrastructure investments

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During any major industrial or economic transition, it is natural for Ministries of Finance to worry about the potential cost of policy missteps. Have the government and investors chosen the wrong technology path? Will consumer behavior or political headwinds change the direction and timing of the transition? Will new technologies, customs, or behaviors emerge that make the policy-led investments unneeded and a redundant waste of capital? And if these investments are redundant and lose value or need to be written off, what impact will that have on the economy, the fiscal budget, and financial markets? These questions assume even greater importance as geopolitical pressures continue to increase competition for scarce financial, political, and economic resources.

Ministries of Finance could be tempted to wait until the transition path becomes clear, or to transfer the risk to the private sector by letting markets decide. Such a strategy could delay a transition or allow other countries to take leadership in the new industry and gain a competitive advantage. In some cases, avoiding the potential financial risk might be worth the delay or loss of potential industry leadership. But such decisions (or non-decisions) are best made when supported by the appropriate analysis.

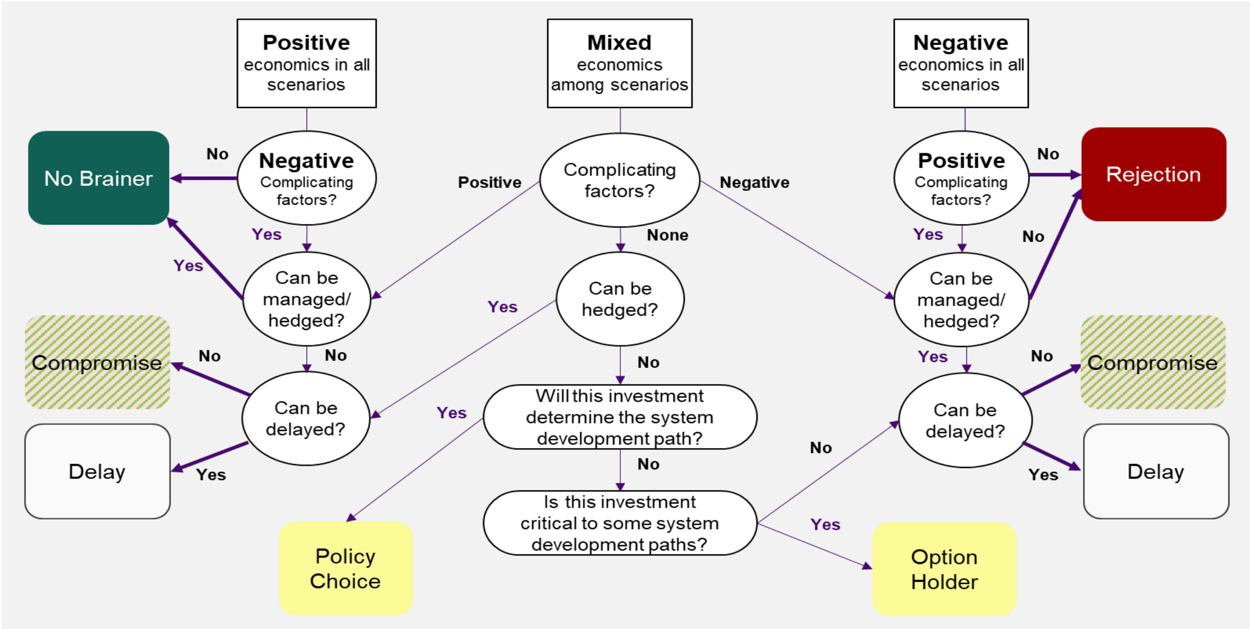
The low-carbon transition shares these risks with other industrial transitions, but with the added complication that delay could make it harder and more expensive to meet the commitments that are needed to mitigate climate change. Meanwhile, letting the market decide without accounting for climate impacts will reinforce the inertia of the existing system, encouraging investments that will either continue to emit higher levels of greenhouse gases or may, in the future, need to be retired early to meet climate commitments, increasing the costs of mitigating climate change.

Thus, governments and their Ministries of Finance need to thread the needle, particularly when it comes to infrastructure investment. They need to understand when they can put off making investment decisions, when they can make decisions with confidence, when decisions are contingent on industrial strategy or other factors. Ideally, they also need to know how they can develop infrastructure investment policy solutions that reduce the risk or impact of changing transition paths.

Scenario analysis is a tried and tested tool for assessing and managing these types of risks. Analyzing possible future scenarios for the energy industry can be a powerful tool to identify and manage this type of uncertainty. Decision-making and investment choices become clearer if a Ministry of Finance can identify and model all potential future energy industry growth models, industry structures, technology and resource supply mixes and use those models to evaluate the economic impact of various infrastructure investments.

With a comprehensive range of scenarios that include the economic impact on infrastructure assets, Ministries of Finance can triage infrastructure investment options using a decision tree like that in Figure 1.

Figure 1. Decision tree for evaluating potential infrastructure investment options



Source: Author

The first step is to evaluate an infrastructure investment under the widest range of potential future industry outcomes. These potential outcomes or scenarios should inform decision makers about potential demand, annual output, energy prices, or energy flows over the lifetime of an infrastructure asset under different energy system structures. These data then inform how various factors affect the economic value of the infrastructure assets in question.

Some assets will have positive economic outcomes in all plausible scenarios. In these cases, the next step is to assess whether some non-economic considerations—called "complicating factors" in the diagram above—impact the investment case.

These could include economic development and geopolitical considerations; for example, a developed country sourcing clean energy from a developing economy could help drive economic growth in the developing country and justify an otherwise loss-making investment. Impacts on scarce resources and supply chains could influence the decisions if, for example, an investment could increase competition for valuable land or mineral resources. Other complicating factors may arise on a case-by-case basis that are not directly covered by the economic analysis.

If the economics are positive and there are no negative complicating factors, or if these factors can be easily managed or hedged, then the investment decision is a "no brainer." That is, it should be ripe for easy approval. If complicating factors cannot be managed fully, the analysis will help policymakers understand the financial cost of delaying the decision or the costs of tradeoffs or compromises involved in addressing the complicating factors.

Similarly, if all scenarios suggest negative economic outcomes, the investment should be easy to reject unless some complicating factors suggest compromise or a delay in making a final decision.

The most interesting cases may be those where infrastructure investments are attractive in some future energy systems, but unattractive in others. Examples of infrastructure investments whose attractiveness could depend on the energy system development path include building hydrogen pipelines in a world that may or may not become dominated by electrification, where electrification has the potential to reduce the growth in demand for hydrogen transport and the value of the hydrogen pipelines. Another example could be a large scale-up of nuclear power in a world where there is a risk that renewable energy sources become abundantly available at low costs and where low-cost solutions, such as battery storage, are available to manage the variability of output from renewable sources. Long distance electricity transmission links are a third example, where economic attractiveness could change if more energy ends up being produced locally and regional imbalances can be managed locally and cost effectively. In each case, changing energy prices or demand for the infrastructure—and the services it provides—could be heavily influenced by the transition path. Getting these investments wrong could put billions of dollars of capital at risk.

However, delay could be equally detrimental if the uncertainty slowed down all avenues for transition or if the delay cut off some potentially promising system development paths, raising transition costs. For instance, our research suggests that the cost of hydrogen production will be partly driven by the scale of the hydrogen industry and investment is needed to build the scale and drive down costs. If there is no action to build scale, hydrogen costs could remain uncompetitive for the foreseeable future. In that case, only conscious policy decisions to pursue the hydrogen economy could be successful. Within that context, individual infrastructure investment decisions would need to consider their contribution to technology and system development, including future cost reductions.

Policymakers might consider rewarding investors for this contribution to develop the industry more quickly. However, with uncertainty regarding which technology would win, and whether the hydrogen transition would be successful, these investments could be at risk from factors such as an unexpected decline in the cost of electrification or battery supply in other transition scenarios. The scenario tool would help identify the risks and the potential scale of these risks and could help policymakers and investors work together to design financing, investment, and policy strategies that reduce the economic impact of alternative transition paths.

In Europe, the economic risk arising from uncertainty around the energy transition path has likely peaked and is falling. The success of wind and solar energy deployment and cost reduction ensures that any future European energy system will include a continued scale up of domestic production from these sources. This production may need to be supplemented with additional energy sources during and after a transition to a net zero energy system.

Options to supplement wind and solar energy include:

- Capturing and storing carbon emissions from fossil fuel generation
- A massive scale-up of nuclear energy
- Major transmission links to import solar electricity from North Africa
- Major increases in electricity generated from biomass
- Importing hydrogen or ammonia to power the energy system
- Massive energy efficiency improvements.

The direction of the energy transition would have significant impacts on infrastructure requirements—including pipelines, transmission, power generation, and energy storage—and on gas and electricity demand and prices. Crucially, the impact will extend to how the price of energy would vary over the course of a day and the year. The variability of the price of energy over the course of the year can have as much of an impact on some infrastructure as absolute prices, particularly where that infrastructure is required to manage the peaks when prices are highest. In those cases, all the value of infrastructure comes from its contribution to managing peak prices, with only a small impact from overall average prices.

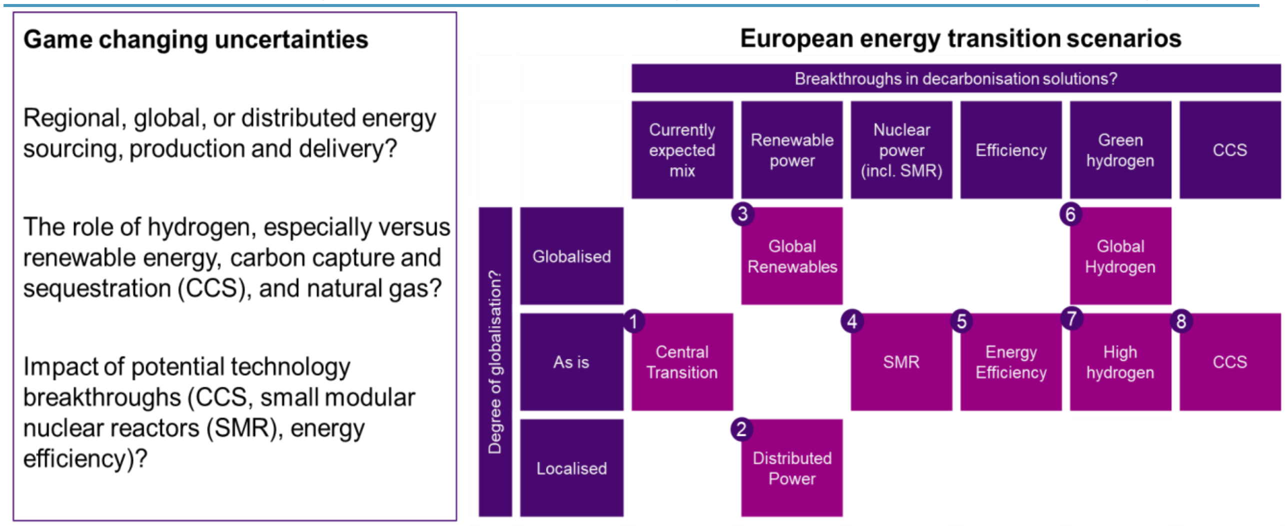
Interestingly, with respect to some elements of the climate transition—namely some parts of energy supply—transition path risks in Europe appear to have peaked and may be declining. This decline could make infrastructure investment decisions easier.

A recent study by the Institute of New Economic Thinking at the Oxford Martin School, University of Oxford (INET Oxford),[1] analyzed a range of energy transition scenarios that align with European Net Zero Carbon goals. The study used these scenarios to assess the financial and economic impact of these paths on the investment case for various energy infrastructure projects in Europe. The analysis

1 With support from the consulting firm WTW and the backing of the Hewlett Foundation.

identified the range of decarbonisation solutions (see Figure 2) for the future that are currently visible, including those described above. For the study, the team built full scale energy transition economic models for each of the scenarios that include energy pricing and demand for the European energy system and modeled emissions to verify that each scenario fully meets European climate ambitions. A summary of the main models used in this analysis is included in the Appendix at the end of this note.

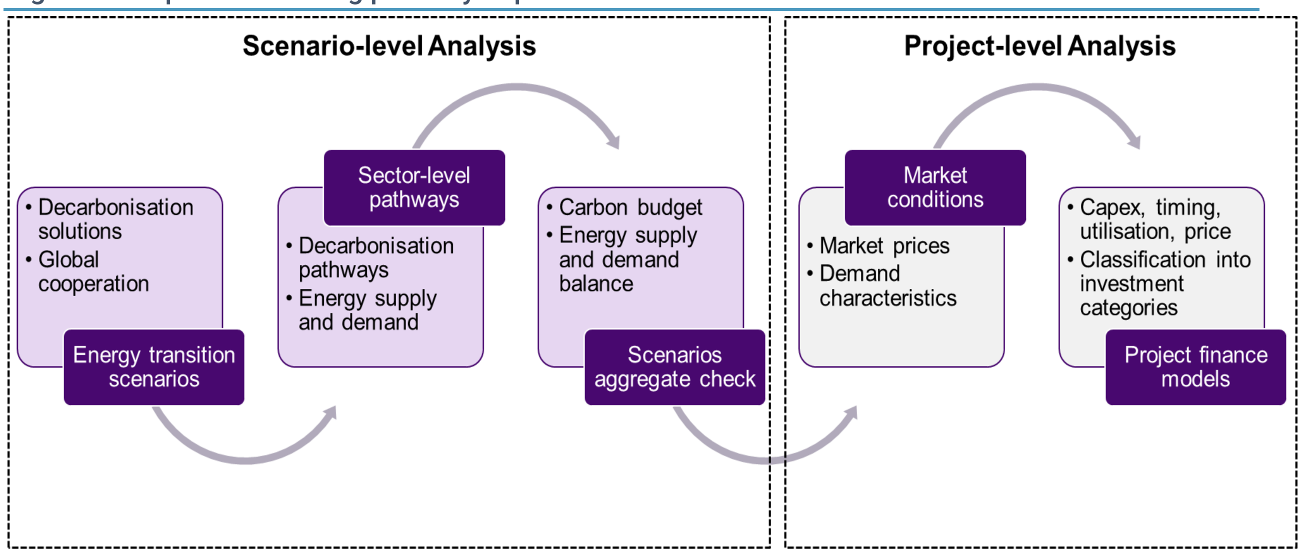
Figure 2. European energy transition scenarios employed for infrastructure investment analysis



Source: Author

The scenario analysis included models of future electricity, natural gas, and hydrogen demand and prices under different scenarios, price variation and volatility, and other factors that would impact the investment cases for various European energy infrastructure options. Finally, the study tested the economics and financing of specific infrastructure investment proposals, including pipelines, renewable energy and hydrogen production, and natural gas infrastructure, to assess the impact of different transition paths on financial risk: see Figure 3.

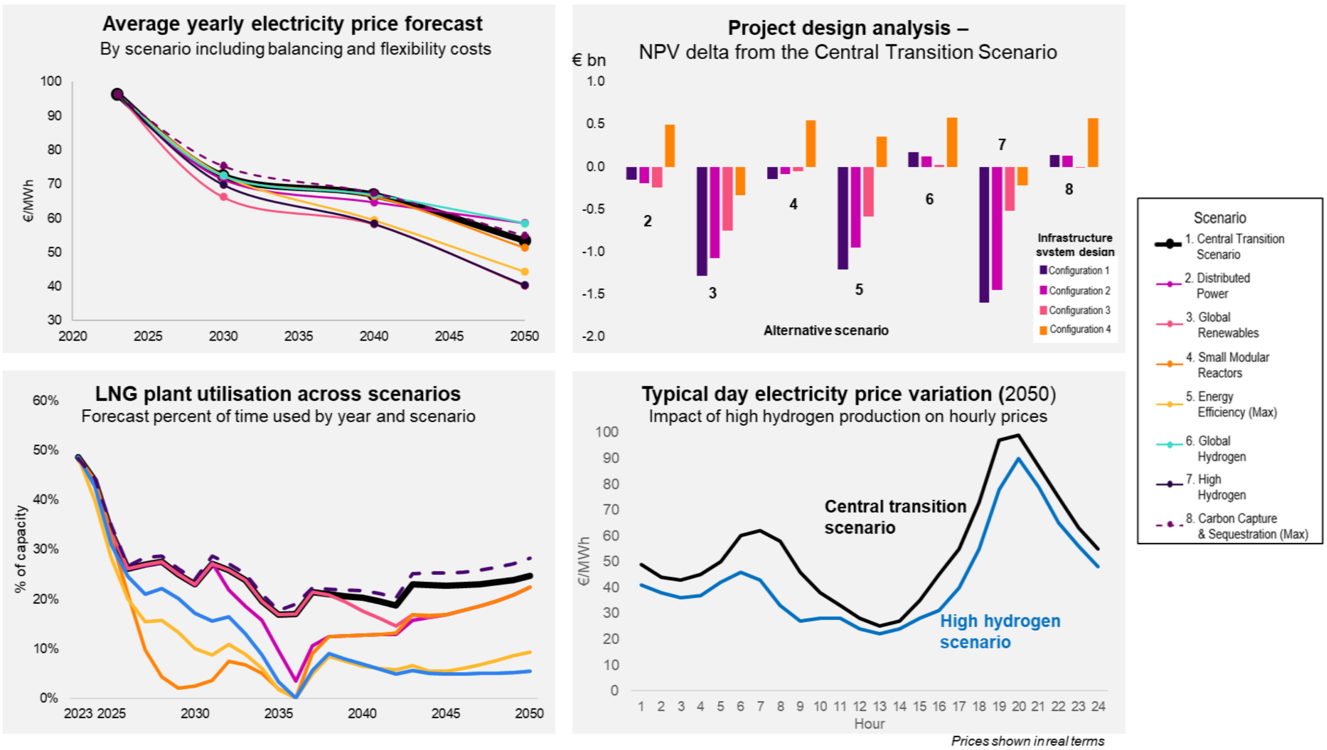
Figure 3. Steps to evaluating pathway impacts on infrastructure investments



Source: Author

The study found that although there continue to be large uncertainties driven by diverging technology paths (see Figure 4 for some sample outputs), the financial impact of technology development and transition paths on various investment opportunities was smaller than previously observed and is likely to continue to fall. The differences between paths are no longer large enough to have an impact comparable to the risk of transition delays, lags, bottlenecks, or policy missteps.

Figure 4. Sample outputs from market analysis of European energy infrastructure



Notes: In the top left and two bottom graphs the different colors correspond to the scenarios as listed in the legend to the right. For the top right-hand graph, the numbers refer to the same set of scenarios (each in comparison to Scenario 1 – the central scenario). The different bars under each scenario refer to different configurations of the infrastructure project in question. In this case, differences include concentrated solar power, Solar PV, Solar PV supported by batteries, and combined solar and wind.

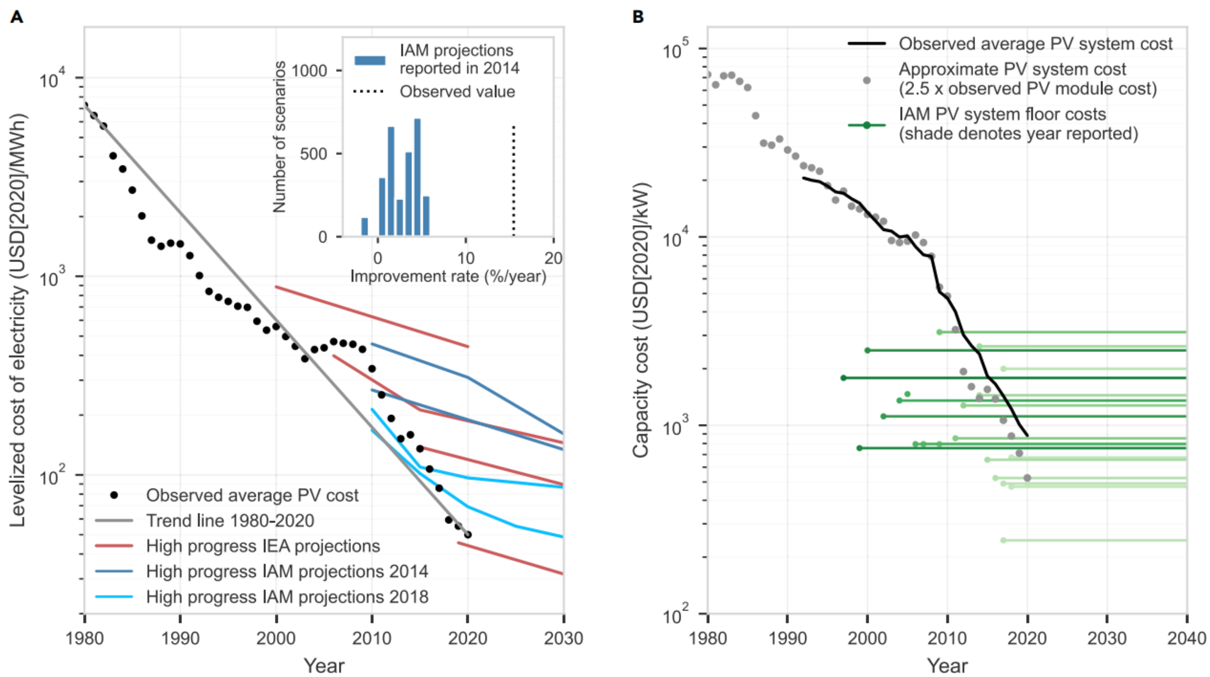
Source: Author

These findings contrast with views from several years earlier where uncertainty over the makeup of the energy transition was acute.

Transition path risk is declining primarily due to the falling costs of renewable energy and energy storage. Path and technology risk has declined for two related reasons. First, the cost of renewable energy generation and battery storage has fallen significantly and continues to fall, while the related manufacturing and installation capacity continues to grow. For example, the European solar market grew 40% in 2023 compared with 2022, according to Solar Power Europe, while according to the US National Renewable Energy Laboratory (NREL), utility-scale solar PV costs fell by as much as 82% between 2010 and 2020. Evidence suggests that these trends will continue, strongly influencing the economics of future European energy system options analyzed in the INET Oxford study.

Technologies such as solar, wind, batteries, and hydrogen electrolyzers have experienced price declines that follow trajectories observed in a range of other emerging technologies, such as computer chips. The design, technology, and manufacturing improve as these technologies mature and are widely deployed. Costs fall as the industry grows, leading to efficiencies from so-called "learning by doing" and economies of scale in production and deployment. Statistical analysis of the history of similar technologies demonstrates that these cost declines are relatively consistent and predictable rates. For example, Solar PV module costs have declined at a rate of around 20% for every doubling of cumulative global output. (See, for example, the cost of solar PV as a function of time—partially driven by cumulative deployment over time—as illustrated in Figure 5, compared with the expert forecasts for cost improvement issued at various times.)

Figure 5. The declining cost of renewable energy has followed a consistent trend of falling costs related to time and deployment levels: examples from solar PV system costs



Source: Way et al. (2022)

There is no reason to believe that this cost decline will not continue as it has for the last 30 years (although a doubling of global output gets harder as the industry grows over time). Therefore, these lower costs set a benchmark against which other energy supplies must, at least in part, compete. Meanwhile, battery storage, which partially helps overcome a major deficiency of wind energy and solar PV—that they do not generate when the sun is not shining or the wind is not blowing—is also experiencing sustained cost declines.

Second, less progress has been made in technologies such as carbon capture or small modular nuclear reactors (SMR). Slower progress has delayed the potential timing of scale-up to the point where even a major breakthrough in the next few years of mass production of, for instance, SMRs would not alter the investment case for energy infrastructure built this decade, such as pipelines, electricity transmission and storage, or renewable energy generation. The time required to scale up and deploy SMRs implies that the total energy supplied over the next 20 or so years would have only a small impact on overall energy supply or prices over the investment horizon of most energy infrastructure assets, even in the most optimistic scenarios.

Europe will need to reform electricity markets and integrate hydrogen production within these markets to realize the full benefits of these declining costs. The INET Oxford scenario analysis focused on the pure economics and financing of infrastructure where investors, whether public or private, can expect to receive the economic value produced by their investments, no more nor less. For example, the modeling assumes that if a new pipeline could decrease the cost of energy supply to a region that needed that energy by one billion Euros, that pipeline would be financially viable if the total costs were one billion Euros or less.

Unfortunately, current energy and electricity market designs could distort economic incentives and financing to the point where investors might see significantly less (or more) value than they contribute to the economy. In that case, energy regulation and market design could create risks and barriers to investment that would significantly increase both costs and systemic financial risks.

Current electricity markets were designed in the 1980s and 1990s to optimize electricity systems deploying mainly a mix of coal and gas fired generation, with nuclear and hydroelectric generation in support. These market designs provide incentives to generators to manage fuel costs and fuel price availability, to ensure that fossil fuel powerplants are available to react to changing demand, particularly at times of peak demand or peak volatility. These markets offer strong and successful incentives to optimize fuel costs, efficiency, flexibility, and capital costs. In markets where the management of fossil fuels is less important, these designs may become anachronistic.

Future electricity systems built around renewable energy are likely to face different issues than electricity systems of the 1990s. Electricity systems built around renewable energy have no fuel supply or fuel price risk to manage, availability is determined mainly by factors beyond the control of operators—whether the wind blows or the sun shines—and resources such as battery storage, hydrogen production management, and demand management become critical to the low-cost and reliable operation of the system. Tying electricity prices to fossil fuel generation prices will increasingly impose risks on renewable generators that they cannot manage, increasing the risk and financing cost of renewable generation without incentivizing any investment or operating behavior that benefits system costs or reliability.

Crucially, mixes of offshore wind, onshore wind, and solar, supported by transmission and storage, are required to keep the system secure in the face of varying and unpredictable weather patterns. Wind and solar energy are complementary to each other, creating greater energy predictability over the course of the day and year than either technology on its own and thus reducing the need and cost of energy storage and back-up. Thus, a market where wind and solar compete against each other could be counterproductive compared with a market where potential wind projects compete against each other for a share of the wind allocation and solar projects compete against each other for their market share.

Current electricity market designs encourage generators to base prices on their input costs such as natural gas or coal, hence electricity prices vary with fossil fuel prices. This means that fossil fuel price uncertainty and price volatility impact renewable energy investment cases, which sometimes obscures the underlying economics. Meanwhile, the market design underemphasizes price signals that should encourage greater demand management and energy storage deployment. Just as importantly, the economics of a zero-carbon electricity system will be heavily influenced by how green hydrogen is integrated into the energy system (i.e., hydrogen gas produced using zero carbon electricity).

The scenario analysis concluded that hydrogen and renewable energy will be less expensive when produced within Europe to meet European demand in all scenarios, rather than being imported from other regions. Further, the study concluded that combined market signals for both electricity and hydrogen are critical in balancing the electricity system and reducing the cost of both electricity and hydrogen. This system should enjoy lower energy price volatility, heightened energy security, and an improvement in balance of payments, and therefore have macroeconomic benefits for Europe.

Ministries of Finance need to be aware of the risks that energy market design can impose on the transition and on the economy, as well as the potential long-term benefits of an energy system that is less exposed to the volatility of global commodity markets.

Other developed economies may face a similar situation, but with key differences. The economics of the emerging European energy system—where most renewable energy and hydrogen will be produced within Europe, replacing imports of coal, gas, and oil imports—suggests that Europe will experience increasing energy independence and a diminished susceptibility to global energy commodity price volatility.

While the study focused on Europe, the lessons from this study could have some applicability to other developed economies. However, each region presents a different set of circumstances, particularly with respect to the degree of energy independence each market will face. North America, for instance, is a net fossil fuel exporter and, therefore, is already reasonably energy independent. Meanwhile, it will face some loss of value for its fossil fuel resources. Japan and Korea may not have enough renewable energy resources in their countries to meet demand and will, therefore, require imported energy resources of some form. Australia could benefit from using its abundant renewable resources (and iron ore deposits) to become a net exporter of some energy-intensive products (such as steel produced using renewable energy and hydrogen).

Finance Ministers should be aware that each country and region will need to develop scenarios and model industry futures that make sense given their own current position and resources, as well as potential future development paths for global technology and resource allocation.

Increased energy independence for developed economies could have implications for emerging markets and global trade flows. Falling renewable energy and battery storage costs are a global phenomenon, driven by global learning and economies of scale, thus we can expect that global energy trade and flows will fall over the long term as more countries move to net zero energy systems. The export of raw materials required to build renewable energy systems is significantly smaller than the current global trade of coal, gas, and oil.

The reduced energy trade will affect emerging market countries differently depending on their circumstances. Countries that are net fossil fuel importers could benefit from lower energy costs as well as lower price volatility and improved balance of payments as fossil fuel imports decrease. Countries with domestic coal, oil, and gas supplies may find that the value of these resources decreases.

However, the benefits for developing economies may be somewhat smaller than for developed economies. Renewable energy, combined with storage, demand management, and increased transmission, partly replaces the cost of fuel with additional capital investment. That is, less money is spent on fuel supply, but some of those savings will need to be invested in new infrastructure. The cost of energy from renewable resources is primarily the financing costs of capital investment: that is, a billion-dollar investment will cost consumers the interest payments plus the depreciation costs, but they will not have to pay for fuel. The extent to which a country experiences higher financing and interest costs determines how much higher the cost of energy from these resources will be. For example, as long ago as 2012, work by the Climate Policy Initiative demonstrated that, all else being equal, financing costs increased the cost of energy produced from wind and solar (per kWh) in India by 24–32% compared with a similar project financed at the interest rates available at the time in the U.S. Low labor and land costs in India could only offset a small part of that cost disadvantage. In general, countries with high domestic interest rates and/or currencies that are devaluing against the dollar or euro, will experience significantly higher energy costs due to the higher financing costs and the higher share of financing in total costs. Fossil fuels are often traded on international markets where financing is available in dollars, thus creating a potential comparative disadvantage for renewable energy in some countries.

For Ministries of Finance in emerging markets, managing financing costs and risks related to projects and markets becomes a critical factor in managing the transition and in enjoying the longer-term benefits of lower energy prices and lower commodity-market-driven volatility in the balance of payments.

Ministries of Finance have a series of urgent tasks to reduce risk and help their countries benefit from the potentially lower costs and volatility of future energy systems:

1. Ministries of Finance need to understand and explore the range of technologies and energy system designs that could become available or evolve in the coming years:
    - Ministries need to develop scenario tools that help them assess these risks and develop coherent strategies for the transition.
    - These tools should be structured to reduce the worry of investors about the impact of uncertain development paths and should increase the transparency and confidence in energy system and climate development targets.
2. Ministries of Finance should work with other policymakers to evaluate and triage infrastructure projects rapidly:

- Ministries can use a preliminary triage, such as in Figure 1, to clarify priorities and identify where more investment analysis work and innovation is required.
- Once the preliminary triage is completed to a satisfactory level, Ministries may need to develop more in-depth models on technology and energy price development to support policy structuring and financial management and hedging, if necessary.
- Ministries of Finance and Energy need to work together to develop a strategic framework with transition priorities and strategies that feed into scenario-based decision-making, helping to unlock projects that are slowed by technology and transition path uncertainty.
- Ministries of Finance should also identify and quantify potential costs and benefits of complicating factors as a critical component of project evaluation

3. For projects where the economics are dependent on the transition path, Ministries of Finance should explore and develop options to manage technology and path risk:
    - These could include market designs, contractual mechanisms, and options to share and socialize risk, enabling path-dependent projects to proceed in an uncertain environment.
    - There is an opportunity to manage risks across countries, sharing technology and transition path risks to reduce the impact on any one country.
4. Energy markets will require reform and innovation from Energy Ministries with Ministry of Finance support:
    - These market designs are needed to reform short-term and long-term energy price formation, and manage investment risks in storage demand management, and renewable energy.
    - Market designs will need to encourage appropriate energy source mixes that reduce system balancing costs and improve energy security.
    - Market designs will need to integrate hydrogen markets with electricity markets and strengthen the integration of transmission into market design.
    - Ministries of Finance will need to monitor and manage the financial impacts of energy market transformation or the delay in energy market transformation.
5. Ministries of Finance need to focus on the financing costs of new, low-carbon energy supplies, particularly in countries with higher interest rate environments and capital scarcity:
    - Energy related interest rates are a critical potential area for international cooperation.

The author would like to thank WTW for their help and contribution to the analysis in this paper.

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Appendix: Summary description of models employed in the infrastructure analysis

Development and future cost forecasting models for technologies including onshore wind, offshore wind, solar PV, concentrated solar power, battery storage, hydrogen capital costs and efficiency.

These models forecast future capital costs and efficiency for various energy technologies based on learning curve and statistical analysis: see the discussion around Figure 5 above and the entire section above titled "Transition path risk is declining primarily due to the falling costs of renewable energy and energy storage." Note that different scenarios consider the impact of faster or lesser scale-up of various technologies globally and for Europe within the global context.

Average annual wholesale electricity prices before balancing costs

The basic wholesale electricity price models forecast the average annual electricity price before balancing and transmission costs based on the mix of generation sources in the market for each year. Note that technology-driven capital cost declines will increasingly drive electricity prices as renewable resources replace fossil fuel-fired generation and additional capital investment in renewable infrastructure replaces fuel costs. Capital costs are expected to fall faster than average prices, as the market will need to compensate older, higher cost, resources (including fossil fuel generation) for their costs.

Without this compensation, the transition would stall as investors would fear future price declines that would undermine the investment case for new generation that might be undercut by future price declines. Thus, the model assumes renewable resources are compensated with long-term contracts, with each year's price declining as capital costs decline and efficiency improves. The wholesale models then blend all energy sources—including remaining fossil fuel generation—to forecast annual prices for each scenario. Scenarios differ in prices due to differences in energy mix and price trajectories for each technology.

Hourly, daily, and seasonal electricity balancing costs and hourly electricity pricing

Current best practice for electricity price forecasting uses power plant dispatch models, where the marginal cost of energy produced by each powerplant determines whether that plant will produce in any given hour. The marginal cost of each plant is calculated based on the costs of variable cost inputs, such as fuel, for each technology and other factors that influence the price at which a generator would produce energy. The cost of the most expensive generator required to meet demand in each hour—that is, the marginal generator—sets the price for that hour.

While these models reflect the historical operating practices of electricity market operators seeking to minimize system costs and maximize efficiency for electricity systems dominated by dispatchable fossil fuel generation, these models struggle in a future world where most generation sources have near zero marginal costs. For example, wind, solar, and to a lesser extent nuclear and some hydroelectric generation have generation that is either inflexible or is dependent on weather and therefore has zero marginal cost. Furthermore, these dispatch models also developed before batteries were available in large quantities to balance demand.

To reflect future electricity systems where batteries and non-dispatchable variable energy or zero marginal cost energy are more prevalent, we have designed alternative models for hourly price forecasting over the day and year. These models begin with a forecast of the range of residual energy demand/supply that will require balancing in each hour. This residual is based on the hourly demand profile offset by the non-dispatchable energy, including renewable energy production, in each hour. Then, the models forecast the cost of different types of balancing services from various balancing service providers, including short- and medium-term battery storage, demand management, and dispatchable generation. Critically, the cost of balancing services depends on both the frequency that the service is called upon (number of times per year), and the duration that the service is required (in hours). For example, the annualized capital cost of a battery divided by the amount of kWh of balancing that the battery provides per year will determine the cost per kWh of load balancing. Meanwhile, the amount of kWh that a battery will balance per year depends on the size of the battery and how many times that battery would be used each year. Thus, balancing services for a battery that is used once a year to meet peak loads would be 200 times higher than batteries that were used 200 times a year.

These models enable us to forecast how prices would vary over the course of a day in markets where no fossil fuel generation was available to balance the system, but also during the transition where fossil fuel generators provide balancing services in addition to energy supply.

This analysis was also supported by simplified models of seasonal balancing requirements using hydroelectric supply where seasonal storage is available, natural gas and hydrogen backup, and industrial demand management.

Once again, prices vary, dependent upon scenario demand, prices, and energy mix.

Electricity prices including balancing

Further models combine the average annual price and balancing costs to forecast total electricity prices for producers and consumers. Note that these prices depend on the timing and flexibility of demand and/or production of electricity.

Domestic and global hydrogen pricing models

Various models calculate the price of hydrogen based on the capital costs and efficiency (from the technology models) and energy prices (from renewable energy technology models in one instance, and from European energy prices as above in another instance).

The cost of hydrogen produced globally and imported into Europe is forecast based on the lowest cost hydrogen production from dedicated renewable energy resources, combined with transport costs. For hydrogen produced in Europe with facilities that have dedicated renewable energy supply or are not connected to the electricity grid (and are thus assumed to employ dedicated renewable energy production facilities), we estimate energy input costs based on the electricity costs from those facilities with a per unit capital cost component that includes annualized capital costs amortized over hydrogen produced each year.

Grid-connected renewables—which ends up being the most economical resource for much more than half of European hydrogen supply in nearly every year in every scenario—optimize their production based on hourly electricity prices from the wider electricity market as in the models above. As hydrogen production increases, it increases demand for electricity during times where there previously was excess electricity production. The grid-connected hydrogen models have batteries and hydrogen production competing to deliver flexibility services and set the hourly prices accordingly. Hydrogen production thus smooths electricity prices (and reduces battery demand) until the point where additional on-grid hydrogen is no longer less expensive than off-grid produce hydrogen, at which point the remaining hydrogen is produced off-grid.

Global gas and LNG models

Global gas and LNG prices are derived from WTW's global gas and LNG models. These models calculate the delivered price of gas and LNG to demand nodes across the world, based on the marginal cost of supply on a field-by-field basis. The models use a linear programming model to determine the price of gas at supply nodes and demand nodes around the world for gas and LNG.

European gas and LNG models

The European gas model is a sub-module of the global gas model. This model includes dispatch of gas storage in Europe, options to reduce gas demand through fuel switching in electricity and chemical production, and feedback loops to global LNG prices. These models then feed back into utilization forecasts for LNG terminals in Europe under different scenarios.

Renewable energy and transmission sufficiency models

Within our analysis, we measured the renewable energy build-out capacity within Europe by technology, based on various analyses. The analysis suggested that, with sufficient transmission capacity and debottlenecking of the current European grid, there was sufficient renewable capacity to meet European needs under each scenario. However, technology mixes were influenced by availability and load shape (with the implied impact on balancing costs).

Ammonia and other minor market models

Additionally, the project incorporated analysis from models on market size and costs for other related energy products, such as ammonia as a product and as an energy carrier.

Infrastructure project models

Finally, the analysis was tested by applying the suite of pricing and scheduling models to specific infrastructure projects (importing renewable energy from Tunisa and building an LNG regasification terminal in Germany). These models included investment cost, operating costs, financing, production, and pricing for a variety of different configurations for each project, forecast annual cashflows over the life of the projects, and produced economic and financing analysis to determine the impact on economic cost of the various scenarios.