Power insecurity:

How has the shift from conventional to renewables impacted the US power system?

2021

Power insecurity

The recent winter storm in Texas has once again raised the issue of power security as a significant exposure across the US, with some of the worst episodes occurring in the country's major states. As with the Californian heatwave of 2020, the growth of renewable energy is typically only part of the story – there are many other contributing factors, several strikingly similar to the events in California despite the differing weather conditions. So, what are these factors, and what part is the ongoing energy transition playing in these events?

Renewables growth and the intermittence gap

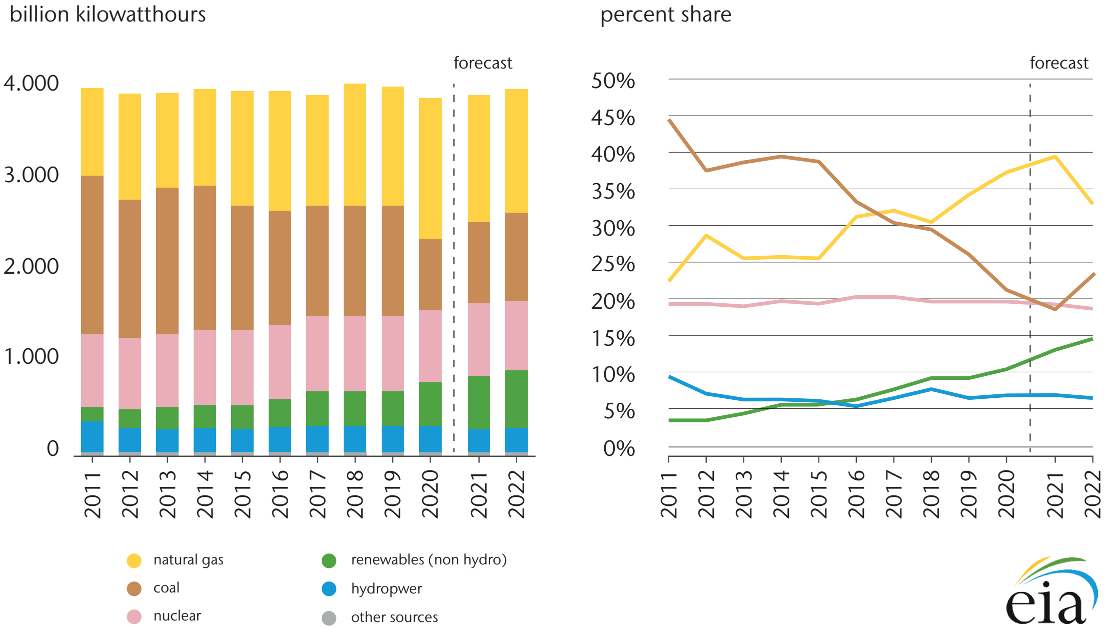
2019 was a record year for renewable growth in the US, with the Energy Information Administration (EIA) estimating renewable energy accounts for 11% of energy consumption. While there is evidence to suggest COVID-19's economic uncertainty damaged the continuation of forecasted growth in the sector, renewable capacity was still expected to grow by 4% globally, according to the EIA in 2020.

One significant effect COVID-19 had on the sector was to delay construction projects through disruption to supply chains. However, it is expected that such projects will restart in 2021 as demand returns. The EIA notes that the clear majority of 'new energy' coming on line in the US by close of 2021 will be renewable, calculating 70% of total new generation will come from wind (scheduled to add 12.2GWs) and solar (15.4GWs). In terms of fossil fuels, gas trails behind with an additional 6.6GWs.

Despite positive headline figures for renewables growth, the EIA also points out that, while growth in 'new' energy is a one-sided affair in favor of renewables, the shift in the market around existing generation doesn't paint nearly as pretty a picture. The EIA charts below demonstrate that 2021 will see a shift in fossil fuel generation, with coal increasing generational output at the expense of gas for the first time since 2012/13. This development will likely come as a surprise to many, considering a backdrop of headlines regarding retiring coal stations and increased awareness of environmental, social, and corporate governance (ESG).

U.S. electricity generation by fuel, all sectors

Source: U.S. Energy Information Administration. Short-Term Energy Outlook, January 2021

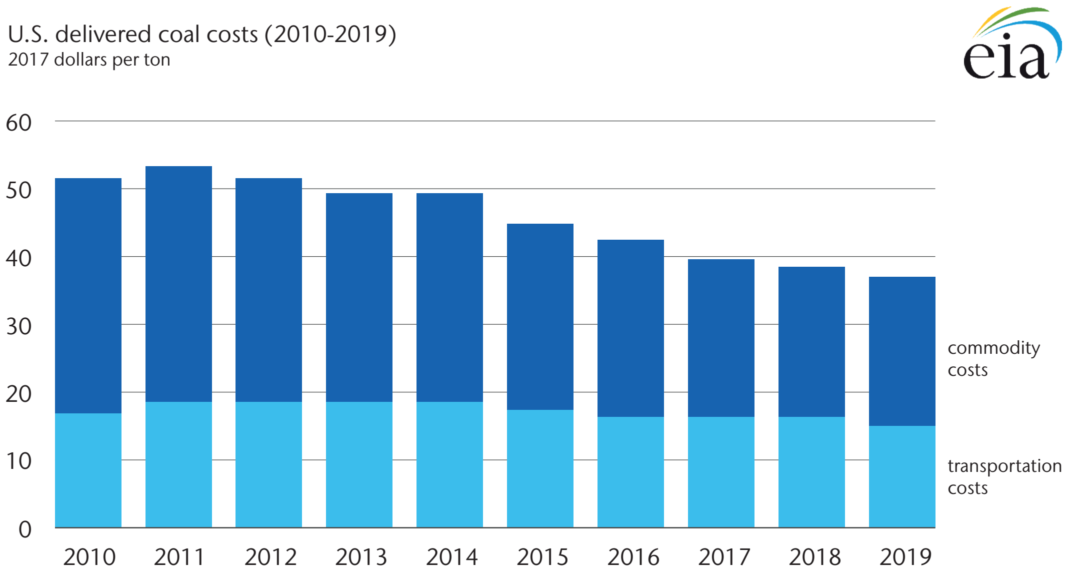


What could be causing this shift from gas, a far cleaner fossil fuel, to coal? Gas prices fell steadily in the US, going back to 2008 when prices collapsed due to falling revenues in the oil and gas industry post the global financial crisis. Deflation, the collapse of economic activity, and the knock-on reductions in consumption led generating companies to skew operating regimes and investment towards gas generation and away from coal. This dynamic had major implications for coal generators, who for decades had provided the baseload generation for the country.

However, in mid-2020, the Henry Hub natural gas spot pricing charts started showing the first significant spike in natural gas prices since late 2018. Year-on-year, the increased flow of new renewable capacity onto the grid (leading to less natural gas production to the market) was a factor, along with the significant economic uncertainty following the pandemic. Spot pricing models continue to forecast an upward trend of increased gas prices, with generators likely swapping fuel sources as part of their generating portfolio to manage costs, maintain margins, and meet demand.

Coal transportation rates in the U.S decreased for the fifth consecutive year

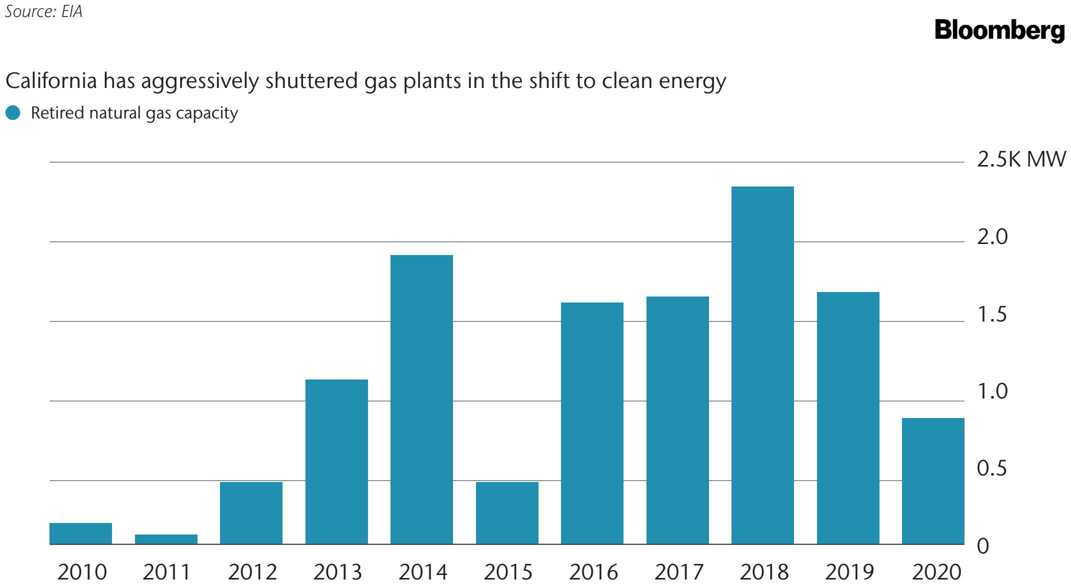
Source: U.S. Energy Information Administration. Coal Transportation Rates to the Electric Power Sector



As the price of gas has started to rise, other factors such as the continued drop in coal transportation costs (year-on-year going back to 2015), mean that coal has become viable at a time when state grids face the challenges of renewable intermittence gaps and, certainly in the case of California, an aggressive gas fleet retirement program.

Vanishing Gas

Source: EIA



This development makes coal feasible again in a 'load follow' position versus its traditional 'baseload' application. The trend of aging coal plants 'two shifting' (running more than one schedule per day, or 'on & off' so to speak) and having sporadic running regimes creates problems across the entire spectrum. Owner generators know this doesn't fit with the assets' optimal and design regime; maintenance costs will escalate on aging assets coming to the end of life hours. Insurers are all too aware running coal plants in this way significantly increases their portfolios' exposure to large losses.

This load follow generation model, regardless of its carbon footprint, can keep the lights on and so remains valuable. However, this model is directly linked to the current limitations around renewable intermittence, dispatch and grid stability.

How do we balance demand on the grid without sufficient battery storage?

As of 2020, while the US generates over 1,200GW of energy, there is only 23.2GW of storage capacity, with the majority coming from pumped hydro-electric (PHE), according to the EIA. However, a key part of decarbonizing the US's grid, by replacing existing fossil fuel generation with more intermittent renewable sources, will require the introduction of much greater storage capacity across the country to manage demand and reduce the occurrence of blackouts. Given that PHE is significantly limited by geographical requirements of sites and slower deployment times, a crucial part of achieving this target will be installing viable alternatives just as green as the generation mix.

At the forefront of potential storage developments are chemical technologies, mostly in the form of utility-scale batteries. According to the EIA, the cost of utility-scale battery storage in the US has dropped significantly, falling by almost 70% between 2015 and 2018 alone. Much of this reduction has been driven by improvements in Li-ion technologies, with greater storage capacity alongside longer storage and duration periods now possible. Development has been motivated by demand for Li-ion technologies in electric vehicles and consumer electricals, but this has been scaled up for use on a utility-scale. This fact, combined with the benefits the systems already have from high cycle efficiency and fast response times, has led to over 90% of the US's installed battery storage coming from Li-ion technologies.

These batteries are now considered sufficient in size and an economically viable alternative to building new gas peaker plants according to Bloomberg NEF, with predictions that batteries may overtake peaking plants in as little as four years. Li-ion batteries, in particular, are reasonable replacements for peaker plants, as these plants are only required to operate for short durations, which suits the technology's capacity, and the fast response times required can easily be matched.

Batteries used in this arrangement operate best when paired with solar generation, as this follows a predictable pattern for charging, with Bloomberg suggesting that this increased solar penetration even drives up the cost of operating traditional peaker plants as they are required to cycle on off more regularly increasing wear and tear on the systems, further adding to the competitivity of battery storage. They also benefit from being able to be situated closer to areas of demands, such as city centres, reducing transmission costs on the discharging side. But, for this to be feasible, the transmission and distribution network will need to be upgraded, as apart from limited roof top solar instillations, the majority of renewable generation is located in more remote parts of the US. Creating "virtual power lines" by also implementing storage systems at peak congestion points could be one such solution to this, as having to overbuild the transmission network would cause concern for policy makers. However, Southern California Edison has already utilized battery storage instead of the planned new peaker plant in Oxnard. Given that an additional 20GW of peaking capacity is expected to be required over the next 10 years, according to Wood Mackenzie, Li-ion could well lead the way in filling this gap.

Nevertheless, in terms of rolling out this technology onto the US grid, batteries are still in their relative infancy with only 900MW of installed capacity as of 2019, although this is expected to rise to in excess of 2.5GW by 2023. California has become the most proactive state in establishing Li-ion projects, with demand prompted by the blackouts caused by the 2019 wildfire season. We could expect that the recent Texan blackouts will lead to a similar increase in demand, both at a consumer level and at a utility-scale.

However, Li-ion and other battery projects still face significant barriers to implementation, such as specific fire codes and tariffs. California already provides regulatory support for planning and funding these projects, and for other states to be successful, they will likely have to follow suit. With significant investigations expected into Texas' grid failings, further regulation that supports storage could be a likely outcome.

There are also issues around the life cycle of current Li-ion technologies. Where the technology is utilized in frequency regulation, the batteries go through continuous charge/discharge cycles, which puts significant stress on the systems, causing them to lose capacity, potentially requiring the premature replacement of battery modules. This raises significant issues with project budgeting. While many manufacturers offer warranties (such as 10-year guarantees) they often include stipulations around how the technology can be used, such as only cycling once a day, limiting how the project can be used over its lifetime. Alternatively, this can be managed by initially oversizing the system to account for reduction of capacity. Continual reduction in battery costs may make this approach more and more affordable; however, this does significantly increase the upfront cost, and as the technology is still in its infancy, the real-world rate of degradation is still not entirely clear.

There are also concerns around the environmental impact of the systems, relating to the extraction of raw materials required for components and how they're managed in their end-of-life (EOL) phase. Lithium extraction has been associated with significant water usage and pollution that has damaged the ecosystem around mines. Similarly, the limited ability to recycle batteries as they come to the end of their usable life can cause significant environmental damage from chemical leakage if the batteries are disposed of in landfill. Given the main goal of the US's energy transition is to limit the environmental damage caused by energy consumption, both of these issues will need to be addressed. This, combined with the other issues raised, suggests that alternative storage technologies also clearly need to be considered.

One potential alternative, longer-term chemical storage solution is redox flow batteries (RFB), particularly vanadium RFBs. Given the infrastructure and management required on their chemical tank systems, RFBs are only economically viable when configured for longer storage times (four hours or more). As such, these systems could be particularly useful in situations that require longer durations of storage and discharge, with the added benefit that the systems have incredibly long-life cycles with no degradation expected to occur within the chemical solutions. Significantly, from a risk management perspective, RFBs are not exposed to any fire risk in comparison to Li-ion technologies. But, at this stage, the larger physical footprint, lower energy density, and higher raw material cost compared to Li-ion technologies appear to have hindered the installation of RFBs thus far. However, with the blackouts in California and Texas exacerbating the immediate need for sufficient short-term and longer-term storage on the grid, this may begin to change.

We would likely expect further novel battery chemistries to emerge throughout the US's decarbonization process, aimed at increasing capacity and captializing upon more abundant raw materials.

Ultimately, the success of rolling out energy storage in the US will rely on investment and support for these developments to ensure the most efficient batteries can be utilized on the grid. Regulatory support, from both individual states and the federal government, will also play a key role in this process. Order 841, a federal directive for regional grid operators to remove barriers to electric storage resources, is one such positive step. It opens up transmission grids to energy storage, removing the reliance on different state-by-state mandates and allowing battery storage companies to compete in the generation mix. States such as California, Nevada, and Virginia, which have set specific targets for storage developments, is another. However, more will ultimately need to be done at a legislative level if the US's current de-carbonization targets are to be met. Other storage solutions beyond batteries will also likely play a critical role, so should be considered too, particularly if they become cheaper and less environmentally damaging than battery developments.

Grid dynamics and how power is traded

In the US, the grid will typically accept generated energy to match the demand for electricity at any one point. Utilities are tasked with meeting the required 'net load', which is effectively the difference between the scheduled/forecasted load demand versus what level of power may be available through generation at that point. Any shortfall in matching demand to purely renewable energy could be due to demand outstripping total renewable availability or production or demand for electricity coming at a point where the total availability of renewables cannot be exploited due to conditions. Solar, for example, typically wanes and ramps down of an evening as people finish their working day, and evening demand starts to spike. Such was the case in California in 2020 as the heatwaves of August clashed with the reality of an advanced CA State renewables strategy, the accelerated retirement of gas and nuclear load, and the inability to maximize battery storage at this point in time.

Utilities in California bid into a day-ahead market to purchase power required by their customers. In August 2020, lower than expected levels of activity on the grid led utilities to miscalculate actual demand levels as being considerably lower than would be required. The California Grid Operator is understood to have under-scheduled power requirements in the lead up to the first blackout by more than 3GWs - enough power to serve the home of over two million Californians.

In Texas, the landscape is very different; however, the design and operation of its grid operation also played its part in recent outrages. During the 2020 Californian rolling blackouts, Texan political leaders were championing their own deregulated, merchant approach that has effectively made Texas a power/grid 'island'. The Federal Power Act of the 1930s regulated interstate trading of power, and by agreeing to not export power outside of the state, Texan utilities were able to avoid federal regulation. The obvious downside to this being an inability to import power from other neighboring states during times of shortages, such as the ongoing cold snap.

Texas generates circa 25% of its power from wind. While the weather affected renewable energy infrastructure, the president of the Texas state regulator (ERCOT) commented that nearly twice as much power from natural gas or coal plants had been knocked out by the cold weather and a failure to 'winterize' generating plants. Winterization packages essentially protect assets such as a wind turbine from extreme cold via thermal strip heating and have been widely utilized in Europe. The downside for Texan generators is additional costs clashing with profit margins.

On the conventional fossil generation side, the outages caused by freezing weather created a vicious circle for gas and coal generation. As significant load fell off the grid through gas and coal outages, the electricity that those plants would normally provide meant that gas compressor systems that run on electricity could no longer operate to provide gas supplies to plants that were on line. General gas lines and even well heads were also frozen resulting in the failure of Texas' 'just in time' process for generation.

It is too early to speculate on the fallout from the situation in Texas; however, there may be a need to re-design the grid and market. Suggestions range from links to neighboring states that would benefit from import and export of power, some form of model to incentivize plant availability (thus incentivizing weatherization investment), or an increase in dispatchable power (i.e. not intermittent renewables) to fill the gaps.

Operational regimes and filling the gaps

By their nature, peak loading generation technologies are required to have a fast response and high availability. Their low utilization makes the cost of electricity relatively high as any capital, and operational outlay needs to be recovered via low levels of generation. The table below evaluates the advantages and disadvantages of the various technologies.

Technology	Pros	Cons
Batteries	Rapid response Can be charged at low demand periods	Technology still developing Limited capacity Large footprint
Aeroderivative GT	Rapid response Can be used to give black-start capability Small footprint Proven technology Can run on gas and liquid fuel	Small MW size, around 50MW Inefficient use of fuel in single cycle compared to CCGT High carbon output Relies on fuel availability
F / H class GT	Good response Large size (up 500MW) Relatively low capital cost	Inefficient use of fuel in single cycle compared to CCGT High carbon output Relies on fuel availability
Pumped storage	Rapid response Proven technology Low carbon emissions Can be pumped at low demand periods	Large capital cost Sites tend to be remote from demand areas Limited capacity
Diesel Engines	Rapid response Can be used to give black-start capability Small footprint Proven technology Can run on gas and liquid fuel	Small MW size, between 25 – 75 MW Inefficient use of fuel in single cycle compared to CCGT High carbon output Relies on fuel availability
Spinning reserve*	Good response	Inefficient use of fuel in single cycle compared to CCGT High carbon output Relies on fuel availability

* Many turbines sat at between 50% and 80% load to allow pick up when required.

Forbes reported that during the recent Texas power outage, demand outstripped supply by over 12 GW. This is an extreme event, but for a system the size of Texas, a 2 GW power swing over 15 minutes is not uncommon. Most grid systems have peak and off-peak periods, and grid operators are very experienced in managing these movements; the preferred way of delivering power over these periods is with spinning reserve. To deliver 2 GW of power over an hour via the other means would require 35 to 55 aeroderivative GTs, 50,000 BMW i3 batteries or four large GTs. With more renewable power coming on stream and old coal, oil, and gas-fired plants being retired, the issue facing grid operators is real.

In the recent Texas power outage, the operator was met with a perfect storm of high demand, input fuel issues, and poor plant preparedness for a severe cold snap. Most climate predictions expect more severe weather events, and a similar situation could occur during prolonged periods of high temperatures. Traditional plants become significantly less efficient during high temperatures, water resource reduces and winds tend to decrease strength. During these periods, demand is likely to spike as people increasingly use air conditioning.

Extreme weather events may affect equipment reliability, with insurers expected to cover for damage to property but also lost earnings during peak power prices.

The solution in the long term is likely to be provided by GTs augmented by battery plants. The energy transition is beginning to move toward hydrogen generation during peak wind power periods. GT manufacturers are now developing GTs that can run on a mixture of hydrogen and natural gas and solely hydrogen in the future. Hydrogen can also be used efficiently in fuel cells, and it may well be considered as a large-scale alternative to battery plants.

Power plant outage insurance availability and market update

Generally, outage insurance is used by companies buying and selling power in the electricity markets. Power plant outages can result in:

- lost revenue; or
- significant replacement power costs.

These exposures can all be covered by outage insurance. In contrast to business interruption insurance, outage insurance has no waiting period. Furthermore, it also does not require a PD trigger, and another advantage is that it pays out based on a financial calculation that does not require visits by a loss adjuster following a loss.

The bottom line is that the outage insurance market came out fairly well. This is mostly because those seeking coverage are typically more concerned with summer risk in this region. To the extent there was concern about the winter period it had been more for a mild winter (a subsequently lower revenues) rather than an extreme cold. Providers of coverage viewed the coverage as being mostly exposed to the summer period, the traditional period where high demand in ERCOT and the risk of lower generation could have a sudden and typically brief impact on electricity prices. A hypothetical 100MW plant outage during a one-hour spike in prices could have a loss close to a million dollars. This however was not the scenario that played out in February 2021 in ERCOT. Electricity prices spiked but remained elevated for days (not the typically expected hours). This scenario could potentially have significant claims, where the hypothetical loss of 100MWs results in payouts that are in the multiple of millions of dollars. In Texas, one of the contributors to the price escalation was the sharp increase in natural gas prices.

In the end, there were not many insureds affected during this event. From our specific experience as well as further claim discussions with the broader market, there were well under 10 claims coming out of the February 2021 ERCOT cold weather event. The low claim volume is mostly due to the infrequency of winter events in the region and the subsequent lack of interest in protecting for it. Again, most are interested in protecting against the region's summer peaks. Market trends are showing an increase of interest in outage Insurance in all regions and seasons as awareness of climate tail-risk is now more elevated in risk management circles and board rooms. Pricing and capacity remain stable due to continued positive underwriting results and the low impact of this latest weather event on the market. This stability in the market has recently resulted in their ability to add 'lack of wind' and 'frozen coal piles' a insured perils within the capacity performance coverage.

Conclusion

The shift from conventional to renewables is not linear; it is not progressing in a straight line towards a conclusion. Instead, it is driven by an abundance of factors, including demand, economic pressure, ESG, technology, as well as hidden interconnectivities that combine to create an impact that is both complex and contradictory.

Rising gas prices due to COVID-19 and the increased flow of new energy capacity onto the grid have facilitated an accidental coal-comeback. With further economic upheaval and extreme weather events on the horizon, investment and support are needed across the industry to continue developing the most efficient battery storage.

Taking into account the multiple levels of information, scenarios, and factors playing out, how should clients navigate such a fluid landscape? Discovering and understanding the exposures that have/are evolving from the energy transition is the first key step. Aon’s breadth of client base in the US provides it with unparalleled data and experience in the power generation industry sector. Developing the correct solutions and go-to-market strategy to cater for those risks is the next step. Our experience of managing hybrid programs where both conventional and renewable power form the generation mix means we are well-placed in understanding the risk appetite of insurers and available products to best serve clients, balancing generating portfolios of this nature. Delivering the program that provides the correct retentions and risk transfer is the final step in the process.

The significance and size of Aon’s US power portfolio arm us not only with the data to design optimum risk transfer programs, but also provides the leverage and premium base in major global insurance hubs to have a meaningful influence on pricing. In-house engineering expertise and the ability to generate remote and on-site engineering reporting provide Aon with detailed and real-time data for market negotiations. Direct access to key individuals and decision-makers can make the key difference in unlocking insurer capacity. The Aon network is designed with these factors in mind to serve our clients best.

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