An Institute of the Americas Policy Brief

CHARTING A NEW PATH FOR LATIN AMERICA'S ELECTRIC UTILITIES AFTER COVID

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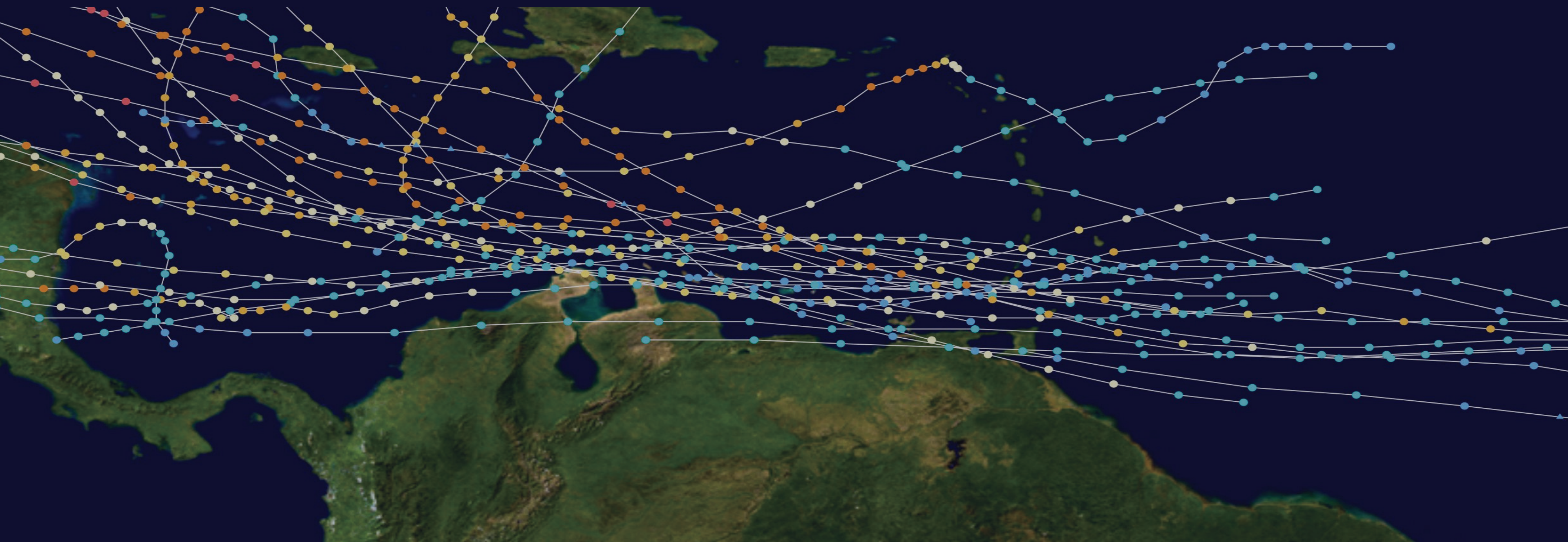

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Global Context

Pre-pandemic, most estimates of global energy consumption showed primary energy consumption rising 1-2% per annum, and resulting in global energy consumption rising ~33% over the next 20 years. The pandemic has clearly caused major disruption in the short-term, with energy demand falling as industrial output has slowed, much less transport has occurred, and many people have stayed at home with offices closed for long periods. Even so, primary energy consumption is expected to grow strongly as the pandemic is finally overcome, perhaps over 1-2 years, and thereafter primary energy consumption should resume its more normal 1-2% per annum increase. By far the largest part, ~75% of growth in energy demand comes through power sector electrification. Within this, renewables and natural gas for power generation are the fastest growing, comprising ~85%. Renewables now form the largest area for new power generation, and their penetration rate has become faster than any other fuel in history. By 2040, electricity has become the most dominant fuel in the fuel mix.

The shift to global electrification is complex. Around 80% of the world's population lives in countries where more energy would improve the quality of life, and not forgetting that the overall population is growing around 10,000 people per hour. This points to a complex energy transition over the next 20 years, in a world that wants more energy, and much more electric power.

The pandemic has given rise to the philosophy to build back better, and build back greener. With this comes the opportunity to accelerate the pace of uptake of low-carbon fuels - solar, wind and geothermal power, nuclear and hydrogen. Recent months have shown a fast paced increase of solar and wind power investment with many new projects going ahead, and the profitability of solar and wind projects increasing. With this comes the challenge of irregular and intermittent supply of solar and wind power and the integration of these supplies to create stable power networks. This often results in a need to develop power storage systems, particularly battery storage. This paper looks at the challenges, post-pandemic, across Latin America.

Introduction

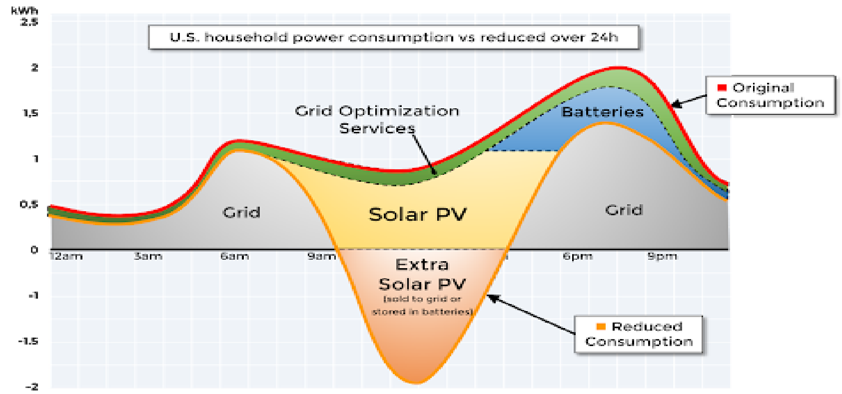
The COVID pandemic will accelerate the changes that Latin American utilities have to make in order to deal with structural issues stemming from the irruption of Renewable Sources of Energy (RSE) and Distributed Energy Resources (DER). Intermittent RSE, and now increasingly, photovoltaic distributed generation (PVDG), as well as electric mobility (EV), have emerged as tangible threats to the vertically separated electric utility legacy model adopted in Latin America during the 1990's. Unlike traditional thermal or hydro generation, intermittent RSE and DER require increasing network and operational (System Operator or ISO) flexibility from both supply and demand (demand response or DR and demand side management or DMS) to accommodate steeper (up and down) ramps resulting from more intermittent RSE coming off and on-line as they take on a larger share of the electricity supply.

This policy brief sets forth the four key challenges that electric utilities face in Latin America in the aftermath of the COVID pandemic. Further, the brief concludes with insights on the directions that both companies and regulators should take to address the 3 Ds: decarbonization, decentralization and digitalization.

Technological Challenges

The increasing adoption of intermittent RSE in Latin American countries will permanently alter the electrical landscape, requiring modifications in every link of the sector's vertical structure. The first challenge, by definition, is how to deal with intermittency.

Intermittency requires back-up traditional generation (or spinning reserves) to come off (on)-line whenever the sun starts (stops) shining and the wind starts (stops) blowing. The larger the share of intermittent RSE over total generation the steeper the slope of both down and up ramps during sunup and sundown (*i.e.* the duck's "belly" becomes larger, see below) requiring faster and faster back-up generation (*i.e.* spinning reserves) to allow/replace PV solar panels or wind mills that go on/off line. Alternatively, back-up generation can be (and is already being) replaced by storage. Batteries charged during peak hours can later replace solar panels whenever the sun comes down (or wind stops) – injecting energy into the grid, hence shaving the evening peak (see below) – thereby replacing traditional alternative (and more expensive) thermal or hydro generation as the next graph shows.



Typical 24-hour residential electricity consumption profile with storage

Figure 1

Once the intermittency problem has been dealt with and solved, RSE have enormous advantages over traditional generation, namely: they are increasingly more economical, they have zero marginal costs as natural resources (*i.e.* sun and wind are of unlimited supply), they do not pollute the environment and, combined with storage, they can contribute to reduce network congestion and losses during peak hours. They may require, however, additional investment in transmission and/or storage to fully exploit their potential.

Intermittent RSE in Latin America are normally located in rural areas, sometimes thousands of miles away from energy consumption centers. They are geographically scattered, usually requiring up to 1,000 times the surface area than traditional thermal power plants of the same installed capacity.[1] As a result,

[1] Solar PV cells have a power density of about 10 W/m² while for wind mills it is around 1-2 W/ m². Traditional thermal generation has a power density of between 200 to 1000 W/ m². In other words, to have one W of installed capacity you need a geographical

solar and wind projects have smaller installed capacities than their thermal counterparts. The combination of faraway locations that are geographically scattered and have smaller installed capacities generates more capillarity in transmission networks which in turn requires more investment in transmission lines, each with a smaller capacity.

The increase in transmission investment needs is also due to the low correlation between power generated in remote rural areas and local consumption. Since the RSE generated power cannot be consumed locally, it needs to be exported elsewhere through transmission lines. The problem with additional investment in high capillarity transmission networks (*i.e.* scattered power plants, each one of lower capacity) is that sometimes the golden rule of investment does not hold. In other words, sometimes the present value of capital + O&M costs of the system *with* the new investment may be higher than the present value of capital + O&M costs of the current system *without* the new investment, including the value of lost load (VLL).[2] Consequently, the expansion may not be economically justified. Furthermore, investments in transmission expansions require the coordination of multiple agents, such as local governments and agencies, firms and users, which creates free riding incentives and cross-subsidies that complicate cost allocation and investment recovery.

Storage can help overcome some of these problems. Again, an investment in a new transmission line may not be warranted because (in a system with high capillarity) the small amounts of power that each line will carry may not justify the additional O&M and investment costs that it involves. This happens because all solar farms generate power simultaneously (*i.e.* when the sun is shining) and within the same region. This high simultaneity generates power peaks during daytime that require high-capacity transmission lines that can handle such power spikes between 6 am and 6pm while remaining idle the rest of the day. This inefficient use of the transmission capacity can be improved with storage because, unlike transmission investment that is lumpy, investment in storage is modular.

By investing in a much smaller capacity transmission line, plus storage, solar farms can generate power during daytime and

footprint between 100 and 1000 times larger for RSE than for traditional thermal generation. Source https://www.brookings.edu/research/renewables-land-use-and-local-opposition-in-the-united-states/

[2] The Value of Lost Load (VLL) is defined as the economic value of a service interruption or alternatively, how much money users would be willing to pay to avoid having a service interruption.

inject only a portion of that power into the (now smaller capacity) transmission lines while using the rest of the generated power to charge batteries that can be evacuated during off-peak hours at night, thus helping shave the daytime peak. Storage, besides helping reduce transmission capacity and losses, is modular, in the sense that its capacity can be expanded (and transported) almost limitlessly without any of the ubiquitous problems that transmission lines have.

In sum, the intermittency problem inherent to RSE has been solved through back-up generation (*i.e.* spinning reserves) and now increasingly by storage. Yet, the increased investment in RSE will require additional investment in transmission capacity because of their more remote and more scattered locations. This additional investment need may, however, be mitigated by new investment in storage that may help stabilize power flows and thus reduce congestion and losses.

A different kind of technological challenge to electric utilities will be posed by DER and EV.

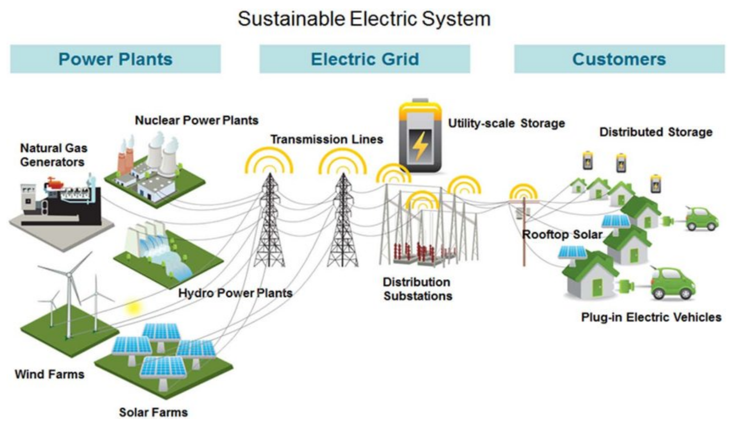
Among DER, DG adds to the intermittency problem that is now faced directly by the Distribution Companies (DistCos). As hundreds or even thousands of PV rooftop panels come on and off-line injecting power into the distribution grid (or charging batteries or an EV)[3] DistCos now have to manage intermittency in their own grids, likely causing them to rely on a Distribution System Operator or DSO and eventually to a Transmission System Operator of TSO as the number of real time transactions multiplies by hundreds or thousands. The former duck chart seen at the generation level now also appears at the distribution level, forcing DistCos to deal with their own duck belly and to run their own dispatch with a DSO and eventually also a TSO.[4]

EV poses the challenge to DistCos of multiplicity of real-time transactions, as does storage, but with an additional problem: EV requires a different distribution network design as users charge EV batteries all around the distribution network, switching places

[3] Notice that the combination of PV rooftop panels plus storage plus high fixed charges provide an ideal incentive for residential users to disconnect from the distribution network and become stand-alone customers as fixed charges now become avoidable.

[4] Third party owned (utility – scale) storage and EV increase even further the number of buy/sell (real time) transactions with the DistCo and thus the need for a DSO and eventually a TSO too.

all the time and thus altering load factors and requiring additional investment in distributions lines and transformation substations to cope with this additional moving demand.



A sustainable electricity network

Figure 2

Demand Challenges

There are structural underlying changes in demand composition that seem to have accelerated during the COVID pandemic. Even though it is too soon to tell whether these changes will be either permanent or transitory or will have both permanent and transitory components, DistCos are already experiencing them, namely:

- Lower demand from commercial customers (*i.e.* smaller crowds in bars and restaurants, theaters, musical concerts, shopping centers, sports events, etc.);
- Higher residential demand due to more on-line shopping, telework and electromobility as users charge their EV at home at night when they sleep;
- (On the other hand) lower residential demand due to DG combined with storage that may induce users to disconnect from the network if fixed charges are too high;
- More demand due to EV use that will likely become a new kind of customer; and,
- Lower industrial demand due to the fall in economic activity (temporary), more self-generation, and higher energy efficiency.

All these structural changes (some temporary and some permanent) will alter load factors and render the topology of the current distribution grid obsolete and in dire need of redesign to help DistCos recover fixed costs that were incurred when these changes were not foreseeable. If rate structures are not redefined and networks not redesigned DistCos will experience stranded investment.

Especially in Latin America, the COVID pandemic and its aftermath of recession has:

- Increased non-collectibles and delinquent accounts, thus reducing revenues;
- Increased theft and non-technical losses; and,
- Increased the amount of people living in slums with one single (collective) account and meter paid for by governments with long arrears.

All these changes will also contribute to alter load factors even further, requiring additional investments that are unlikely to be recovered with the current rate structure. It will aggravate cross-subsidies and will likely call for further tariff increases to cover revenue shortfalls.[5]

Lastly, DistCos may have Take-or-Pay (TOP) Power Purchase Agreements (PPA) that were signed with generators before the COVID pandemic struck. This kind of PPA normally involves a fixed (monthly) payment to generators in line with the contracted (maximum) capacity in $/MW month and a variable payment in $/MWh in line with a pre-defined consumption profile. If this consumption profile is fixed, the TOP clause will require payment of the pre-defined consumption level whether that consumption level has occurred or not.

In other words, the TOP clause will trigger payment by the DistCo regardless of the actual consumption level. During the pandemic months and especially after lockdown, power consumption from commercial and industrial users fell sharply, and though residential consumption increased, collection dropped due to higher unemployment and lower economic activity. If DistCos were required to honor those TOP PPAs they must have incurred severe losses as they bore all the risk of the collapse in demand.

After the pandemic is over, and If there ends up being a permanent (structural) component in this demand composition change, Distcos will have to devise a mechanism to hedge themselves against demand volatility – sharing the risk with generators and/or users.

Economic Challenges

The collapse in electricity demand during lockdown (up to 50% during April in some Latin American countries)[6] has unveiled the

[5] Non-technical losses and the moral hazard problem in collective accounts (slums) can be solved by installing pre- paid meters in each dwelling. This is not a very popular solution among users but it can substantially mitigate the problem.

[6] See A. Chambouleyron (2020) "*Hourly and Daily Electricity Demand after Lockdown: Evidence from Argentina*" in Energia en Tempos de Pandemia, Chapter II, 1 pp. 193-197, EVEx202.

historical distortion in tariff structures that DistCos in Latam have had for a long time. This distorted tariff structure implies sharp revenue reductions whenever there is a demand slump and a steep surge in revenues with a demand increase, thus creating high income volatility.

Volatility is due mainly to the following:

- DistCos' revenues normally come more from variable charges than from fixed charges when distribution costs are essentially fixed (*i.e.* not varying with volume). As a result, DistCos normally prefer fixed charges over variable ones;
- Variable charges do not reflect real time prices of either electricity or generation costs, let alone real losses or congestion costs;
- In DG, the ratio of fixed vs. variable charges affects the incentives of users to install PV panels on their rooftops, the larger the variable component of distribution rates the higher the avoidable cost and therefore the higher the incentive for users to install PV panels due to the larger will savings they will experience; and,
- The opposite occurs with DistCos: the larger the variable component of distribution rates the more they lose when users install PV panels. Again, this is another reason why DistCos normally prefer high fixed charges and low variable ones.

DG also reduces revenues for both TransCos and GenCos as power generated by PV rooftop panels replaces power hitherto purchased by the DistCo in the wholesale market. To the extent that power is only a pass-through component of electricity retail prices, DistCos should not experience revenue shortfalls. However, retail electricity prices normally include network charges that help recover distribution and transmission fixed costs (thus keeping fixed charges low). Therefore, DG ends up reducing DistCos' revenue stream. Again, the extent of this reduction will hinge around the proportion of variable to fixed charges in retail rates. The higher the ratio of variable (avoidable with DG) to fixed charges (non-avoidable with DG) the more incentive there is to install PV rooftop panels and the sharper the revenue fall for DistCos.

- The allocation of capacity is normally tilted toward users with low load factors (residential), a very inefficient allocation as residential users are responsible for the daily peaks in consumption but they do not normally pay for these costs that they impose on the distribution network;
- Large users (commercial and industrial) normally subsidize residential users;
- High (technical and non-technical) losses are supported by those users who do pay their monthly bills;
- Low load factors in residential users could be increased (*i.e.* evening "peak shaving") by implementing:
    - Real time or Time of Use (TOU) pricing with higher prices during peaks to flatten the daily demand curve (see chart 1);
    - Distributed generation coupled with storage (see chart 1); or
    - Demand response incentives (*i.e.* paying customers not to consume during peaks, storage during daytime, etc.).
- To do this it will be necessary to replace conventional meters with smart meters. However:
    - Customers may not have the incentive to accept smart meters;
    - They may not have incentives to accept real time or TOU pricing;
    - They may not want to pay for the meters; and,
    - Worst of all, smart meters may not be warranted as the reduction in peak demand may not generate cost reductions that justify the cost of acquiring and installing smart meters.

In sum, high volume volatility (such as the one experienced during the pandemic) coupled with a distorted tariff structure (*i.e.* high variable tariff components over the fixed component) creates enormous problems for DistCos because their cost structure is essentially fixed. If we add DG and TOP contracts to this structural problem, the problem is severely aggravated. The demand volatility challenge can be mitigated by restructuring tariffs and the implementation of real time or TOU prices coupled with smart metering and DSM or DR with storage. This solution however may: 1) not be politically feasible, and 2) not be warranted on economic grounds.

Regulatory and Institutional Challenges

The traditional vertically separated electricity utility is clearly in crisis. New renewable sources of generation coupled with DG plus storage and EV are putting the traditional G + T + D vertically separated paradigm in dire need of change.

On the one hand, DistCos' traditional business of (only) buying and selling electricity to captive users is under heavy fire from power resellers, large users buying directly from GenCos, and now from DG and EV. DistCos' business model has to change and diversify – venturing into DG, storage, EV, and other alternative sources of power, as well as digitalizing the distribution network to follow online transactions and quality of service (QoS) in real time.

On the other hand, and to allow DistCos to diversify their business models, regulation must be modernized as well. Current cross-ownership bans pervasive in all Latin American countries no longer make sense. Banning DistCos from owning GenCos (or vice versa) or banning TransCos from owning DistCos or GenCos (and vice versa) when there is competition in the wholesale market and an independent ISO is nonsensical. These cross-ownership bans need be removed immediately and market operations should be monitored by a strong Competition Commission. We need to move from an ex-ante (technology-based) regulatory model to an ex-post (conduct-based) one led by a powerful Competition Commission.

Conclusion

To increase access to electricity through lower prices and cleaner energy matrices it is imperative that Latin America embark on an energy integration program – allowing countries with temporary deficits (surpluses) to import (export) clean power (from or to) countries with low renewable density thus increasing the speed of decarbonization.

In conclusion, the COVID pandemic and its aftermath must be a catalyst for a long-needed reform in Latin America's power sector by addressing the technological, demand, and economic, as well as regulatory and institutional challenges described

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The Institute continues to serve as an honest broker between the public and private sectors across Latin America to help forge a constructive dialogue on the issue of clean energy transitions and emerging economic opportunities derived from renewable energy deployment.

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