Energy

Power surge: Navigating US electricity demand growth

How the rapid rise in electricity demand could impact the transition to clean, reliable, and affordable electricity. And what utilities can do about it.

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Executive summary

Americans are demanding more electricity than ever before.

For the past two decades, U.S. electricity demand growth rates remained relatively flat. Utilities have traditionally helped manage electricity demand and peak electricity demand through forward planning and demand side management (DSM) programs that proactively manage customer energy use. However, the U.S. now faces a sudden surge in electricity demand that requires new management strategies amid utilities' efforts to lead a clean energy transition.

This report leverages ICF's cloud-based renewable energy analytics platform, EnergyInsite, to measure and map electricity demand growth across the U.S. and the constraints to addressing demand. We find that by 2028, U.S. electricity demand could increase by an average of 9% while peak demand for electricity could increase by an average of 5%. By 2050, electricity demand could rise by 57%.

New sources of electricity supply—including utility-scale solar and wind power—could theoretically meet this expected demand growth. But there are significant constraints to building new generation resources, including an electric grid in need of upgrades, slow approvals for new clean electricity projects, and finding suitable locations to build additional clean energy infrastructure.

The rise in electricity demand combined with the nexus of generation, transmission, distribution, regulatory, and policy constraints could slow the transition to clean, reliable, and affordable electricity. We find that the cost many utilities pay for electricity could increase by an average of 19% by 2028 due to the demand increase. Much of the additional costs would be passed on to utility customers.

The challenges are real, but they are not insurmountable. Utilities will need to provide consumers with a balanced mix of new electricity supply and programs that reduce electricity use, especially during periods of peak demand. And utility leaders will need to work in concert with lawmakers, regulators, and those leading customer programs.

This report offers six key recommendations for utilities to stay one step ahead of demand growth and electricity supply constraints while navigating the clean energy transition.

We find that by 2028, U.S. electricity demand could increase by an average of 9% while peak demand for electricity could increase by an average of 5%. The cost many utilities pay for electricity could increase by an average of 19% by 2028 due to the demand increase.

Recommendations for utilities to manage demand growth

1. Create more sophisticated and integrated system planning.
2. Identify ideal locations for renewable energy projects.
3. Evolve the distribution grid.
4. Plan and implement next-gen customer programs.
5. Leverage data and artificial intelligence.
6. Engage with regulators.

Increasing electricity demand

After years of low electric demand growth, the U.S. is experiencing a sea change. A robust American economy, building and transportation electrification, manufacturing of batteries and fuel cells, data centers, artificial intelligence, and cryptocurrency mining are all contributing to new electric demand that's stressing the electric grid.

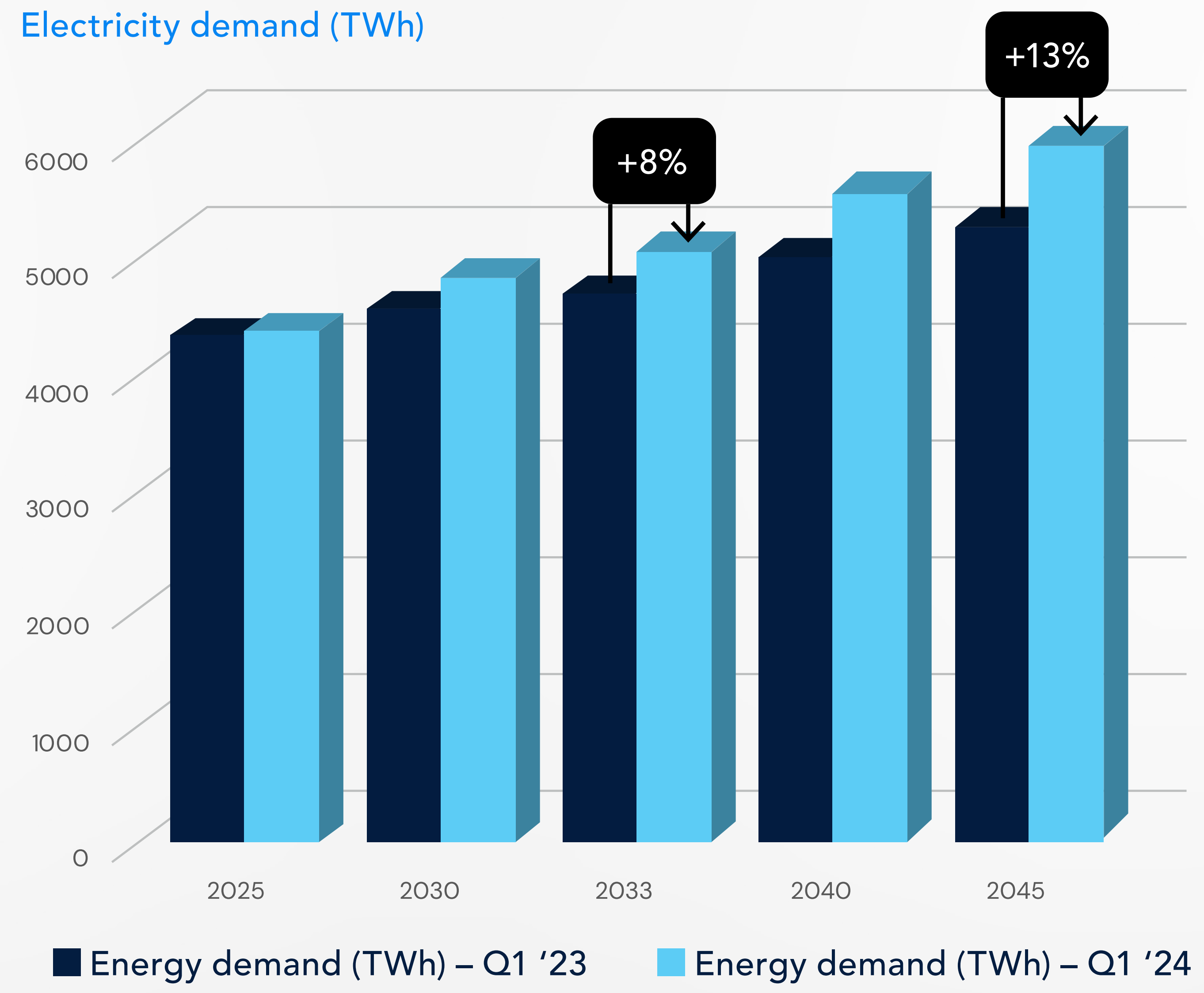
U.S.-wide electricity demand is expected to increase 9% by 2028 and 18% by 2033 —an increase of 2% per year on average compared to the current level in 2024.[1] More importantly for electric grid planners, a similar trend is expected to pan out for electricity demand peaks. U.S.-wide summer peak demand is expected to increase 5% by 2028 and 11% by 2033 relative to 2024.

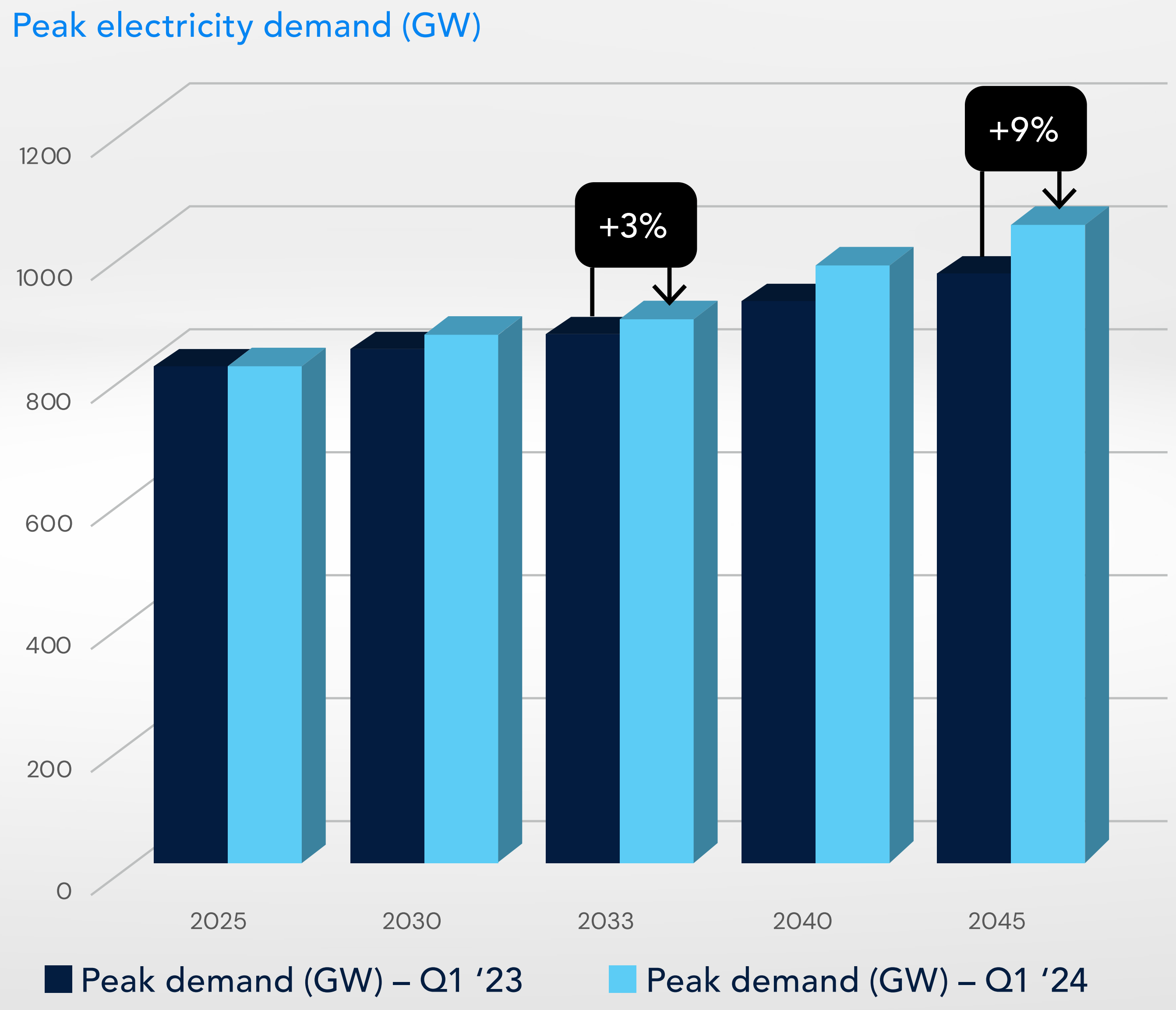
What makes this stark increase in energy demand, particularly peak demand, so challenging is that it simply wasn't forecasted in most projections until very recently. The latest demand projections are significantly higher than projections made as recently as 2023. The divergence between last year's projections and current projections is broad by 2033 and only continues to grow in the coming decades, as seen in Figure 1. Electricity demand projections could rise further than they already have.

Peak demand is crucial because utilities must ensure they have the infrastructure to deliver enough electricity at these times when it is needed most, even if that level of electricity is only needed for a few hours on a few days per year. Although peak demand traditionally occurs in the evening, and often in the summer, electrification taking place across the country may shift these peaks, making it essential for utilities to adapt to new patterns of electricity usage.

[1] Energy demand represents the total electric power consumed in a year (in terms of MWh or GWh). Peak demand represents the peak demand requirements at peak during the year (in terms of MW or GW). All demand estimates are based on NERC and/or ISO/RTO estimates.

Figure 1: One year change in projections for U.S. annual and peak electricity demand (Q1-23 v. Q1-24)



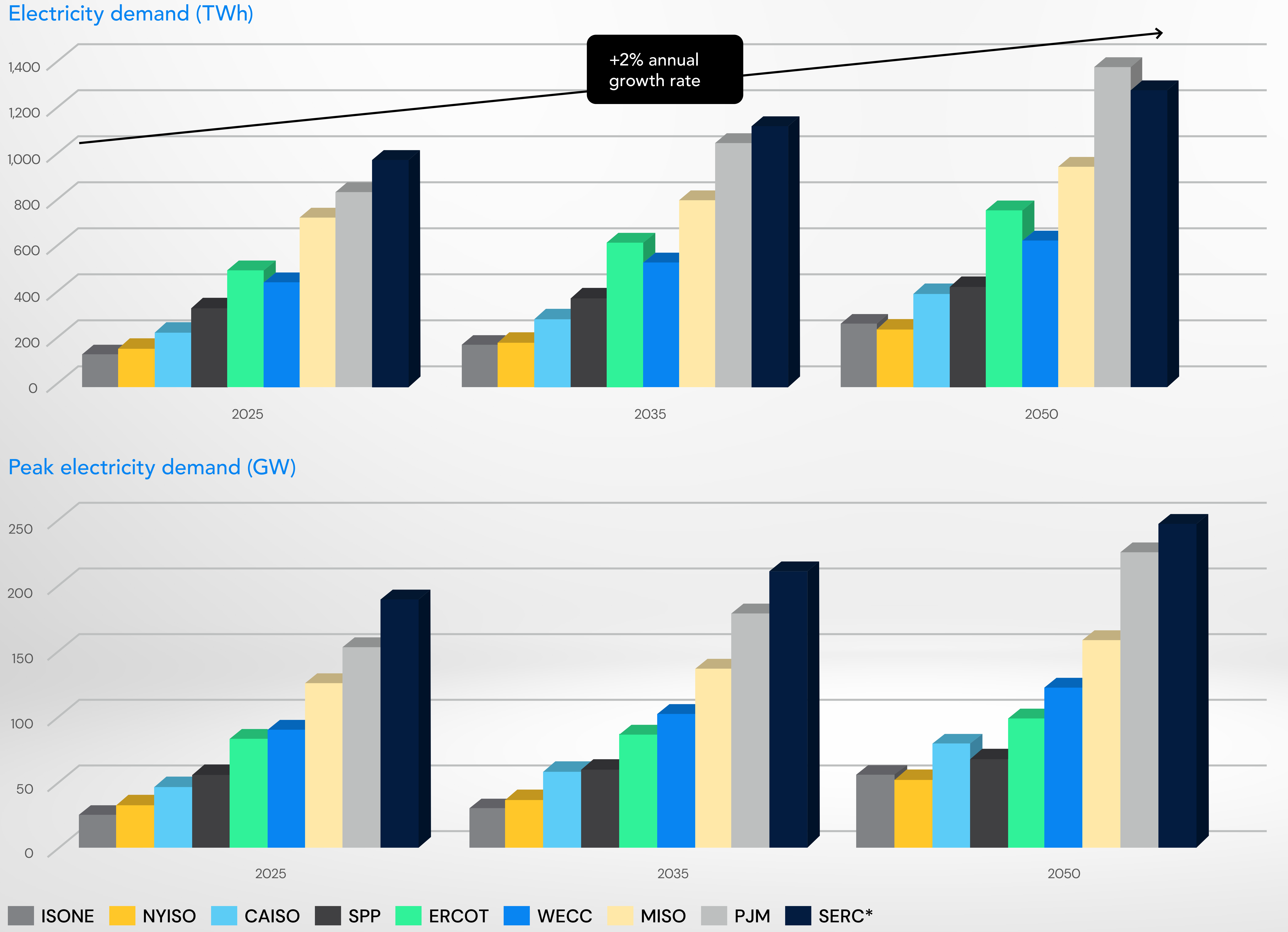


Source: Source: ICF, NERC, ISO and RTO

Demand growth is expected in every region across the country, but the pace of growth will vary by region. The largest increase by far is projected in the Mid-Atlantic states covered by the PJM region, as seen in Figure 2, resulting from rapid building and vehicle electrification and demand from data centers. Demand in PJM is projected to increase 68% by 2050, compared to the U.S. average of 57%.

Peak demand in SERC, which covers 16 southeastern and central states, is projected to grow 31% by 2050, and 124% peak demand growth is expected in ISO New England (ISONE) by 2050.

Figure 2: Electricity demand and peak demand projections by region

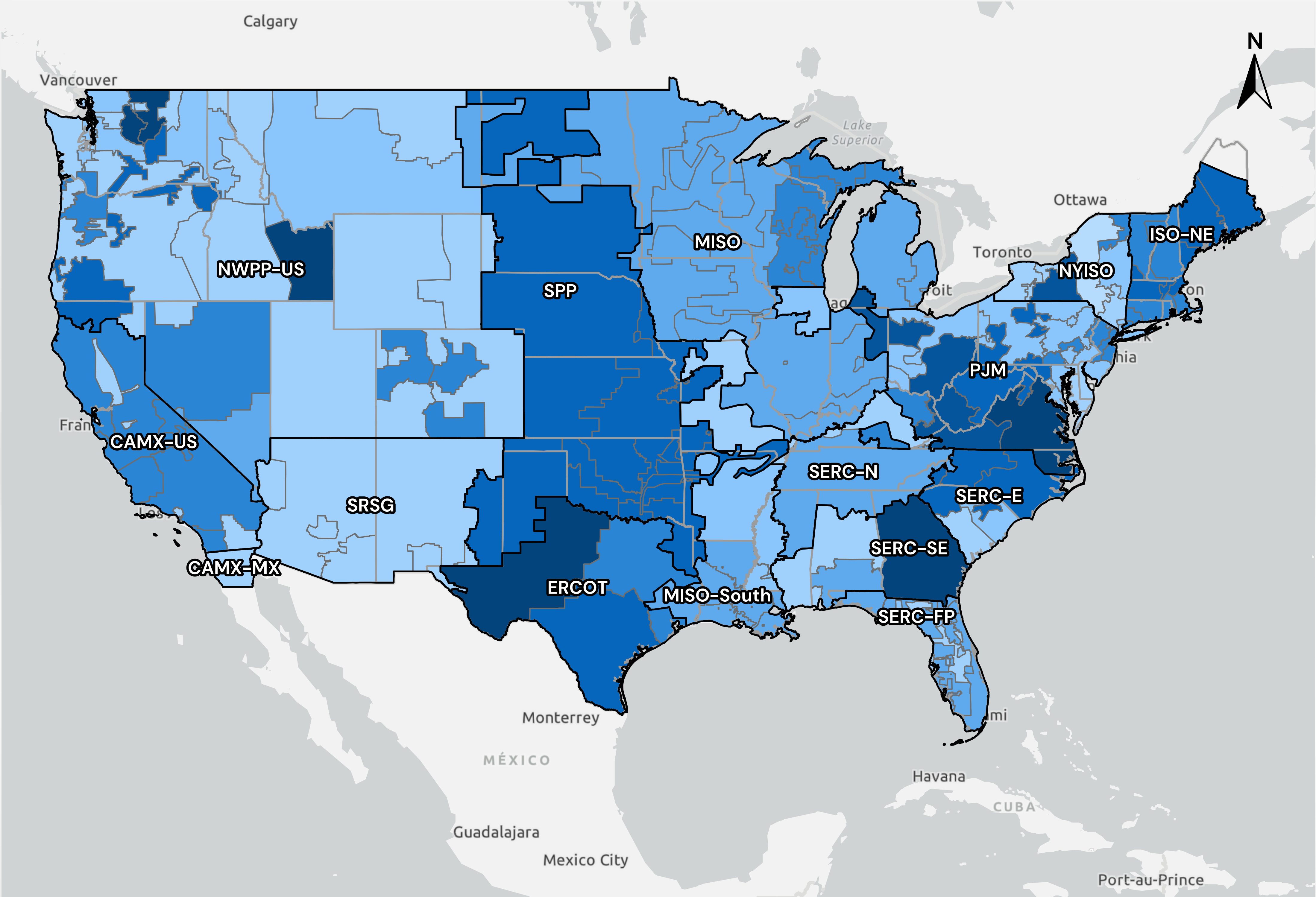


Source: Source: ICF, NERC, ISO and RTO data | *SERC consists of SERC E, SERC-SE, SERC-North, FRCC

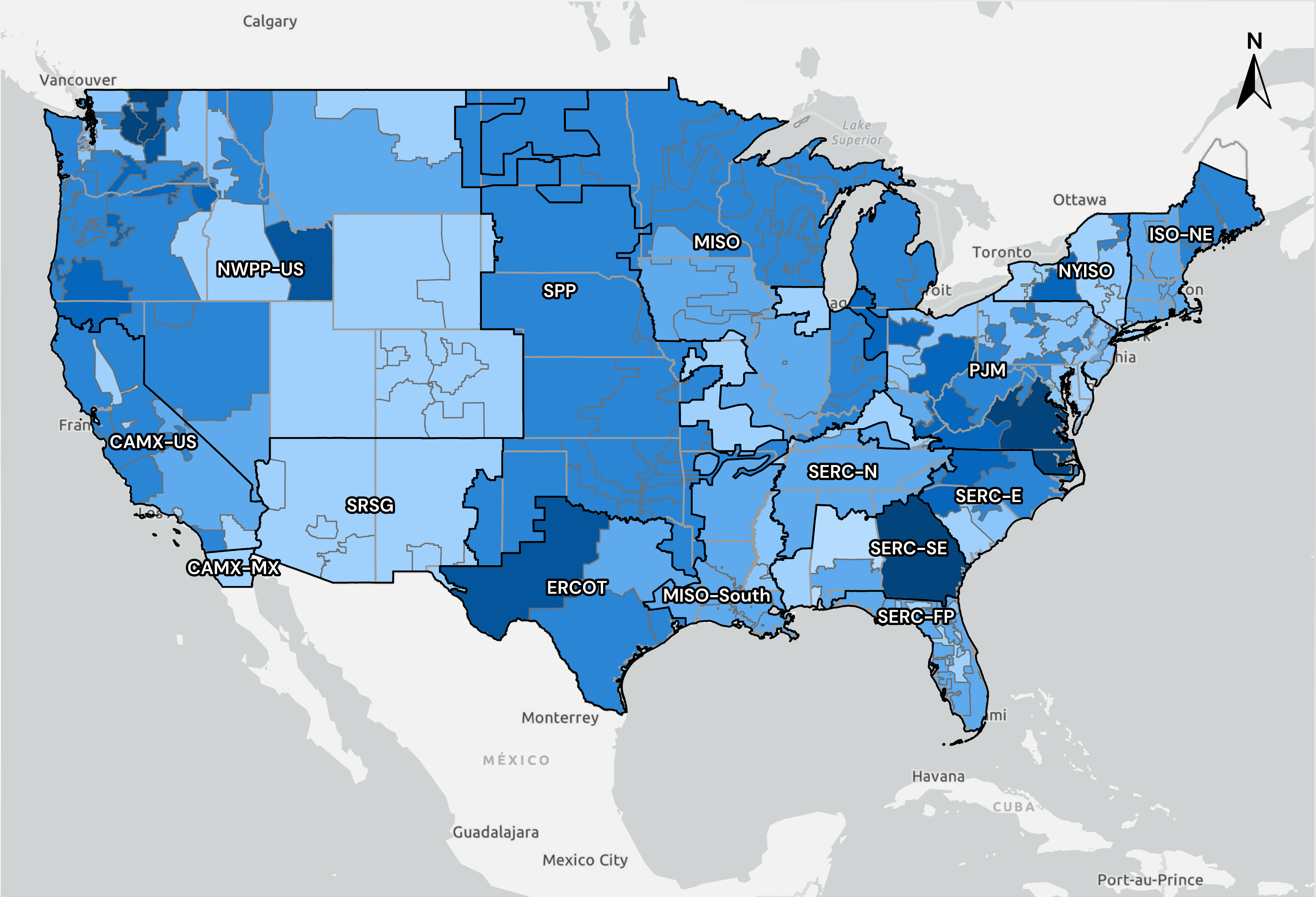
Figure 3 maps peak and overall demand growth rates for different utility service territories and transmission zones based on North American Electric Reliability Corporation (NERC) estimates. Some of the areas—such as the Dominion service territory in Virginia, Southern Company service territory in Georgia, and ERCOT West zone in west Texas—have total electricity demand and peak demand growth rates projected to exceed 25% within the next five years.

Figure 3: U.S. energy demand and peak demand projections

Electricity demand



Peak electricity demand



% Growth (2024–2028)

<–5 | –5 – 0 | 0 – 2.5 | 2.5 – 5 | 5 – 10 | 10 – 15 | 15 – 20 | >20

Source: ICF/NERC

New clean power generation constraints

The geographic differences in demand growth are significant, and addressing these differences requires complex, tailored strategies for each region. It might seem the most obvious solution is to add new sources of clean power generation across the country to meet rising demand. However, a host of challenges make that strategy a difficult task.

Slow interconnection approvals

ISOs and RTOs won't grant a request for a generation project to connect to the grid until they are confident the transmission system will have the capacity to deliver the new supply to where it is needed.

In recent years, the average grid interconnection timeline for new generation projects has increased to five or more years[2], up from an average of four. Close to 2,500 GW of generation and storage capacity remain in interconnection queues across the country.

The success rate of planned generation projects reaching completion is expected to suffer due to these queue delays. Aside from the problem of time, average interconnection costs for projects are also rising in many markets.

Recent regulatory developments may help. The Federal Energy Regulatory Commission (FERC) issued orders 2023, 1920, and 1977 that together are designed to ease the queue logjams, facilitate faster interconnection, and provide the necessary highways to move electrons across the country.

Where to put all the new energy infrastructure projects

Some of the country's most significant renewable energy potential is located far from areas of high electricity demand, and therefore large-scale transmission upgrades are often required to bring supply from new renewable energy projects to the places where electricity is needed.

Upgrading or building new interstate transmission lines involves navigating a labyrinth of siting and permitting requirements, which can take 10 years or more. Land availability is a challenge, especially when the demand growth is concentrated in densely populated cities. When federal land or federal loans or grants are needed to complete a transmission project, additional environmental reviews are needed, which adds to the overall timeline for approvals.

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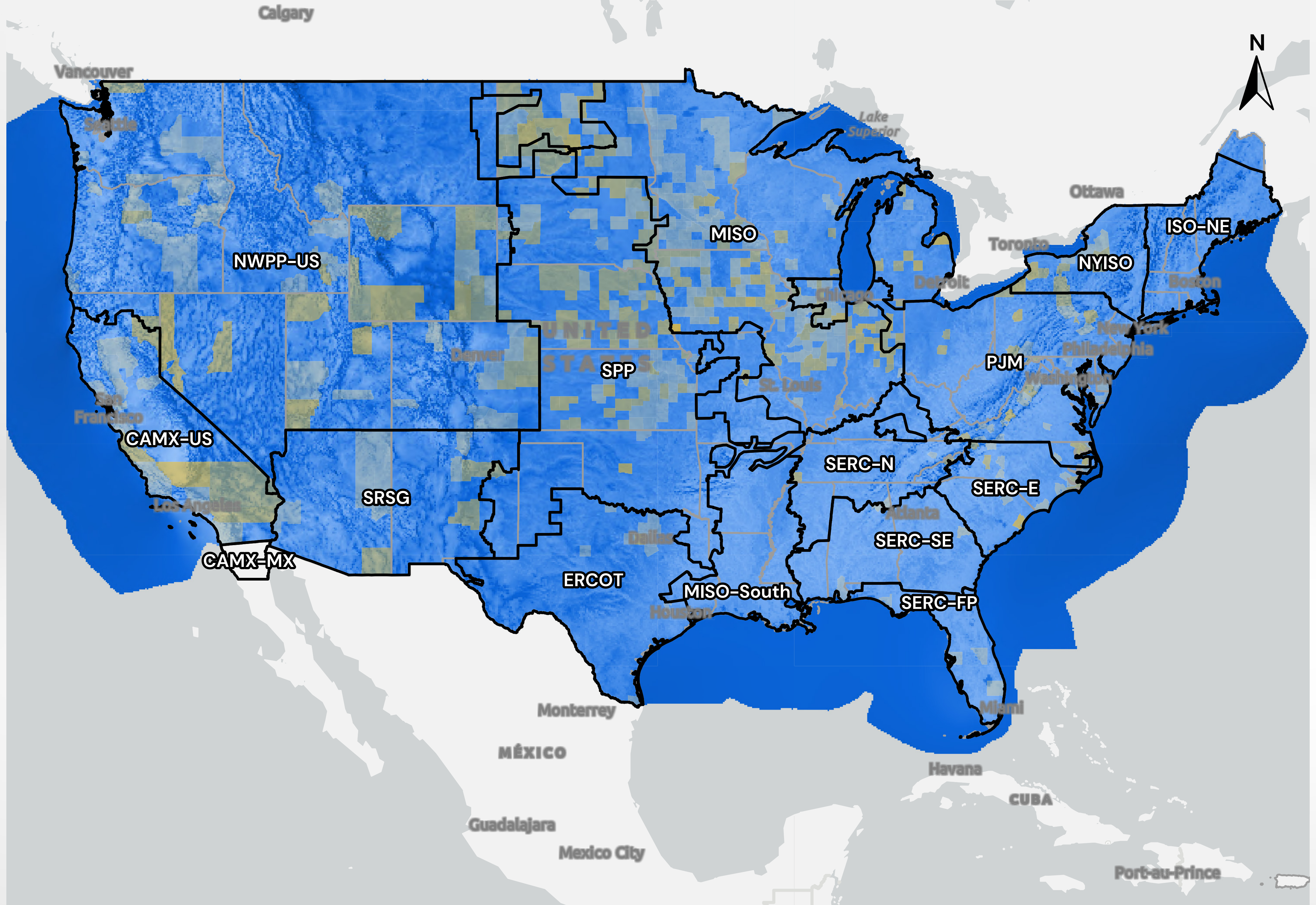
[2] LBNL – See *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection | Energy Markets & Policy (lbl.gov)*

Siting and permitting challenges aren't just bureaucratic. Citizens often raise objections to proposed energy projects near their homes. In response to their input, lawmakers often limit where new wind and solar resources can be located. Figure 4 illustrates the overlap between some of the country's best wind and solar resources and jurisdictions where ordinances have been passed to limit the construction of such projects.

Figure 4: Local restrictions constrain renewable resource potential

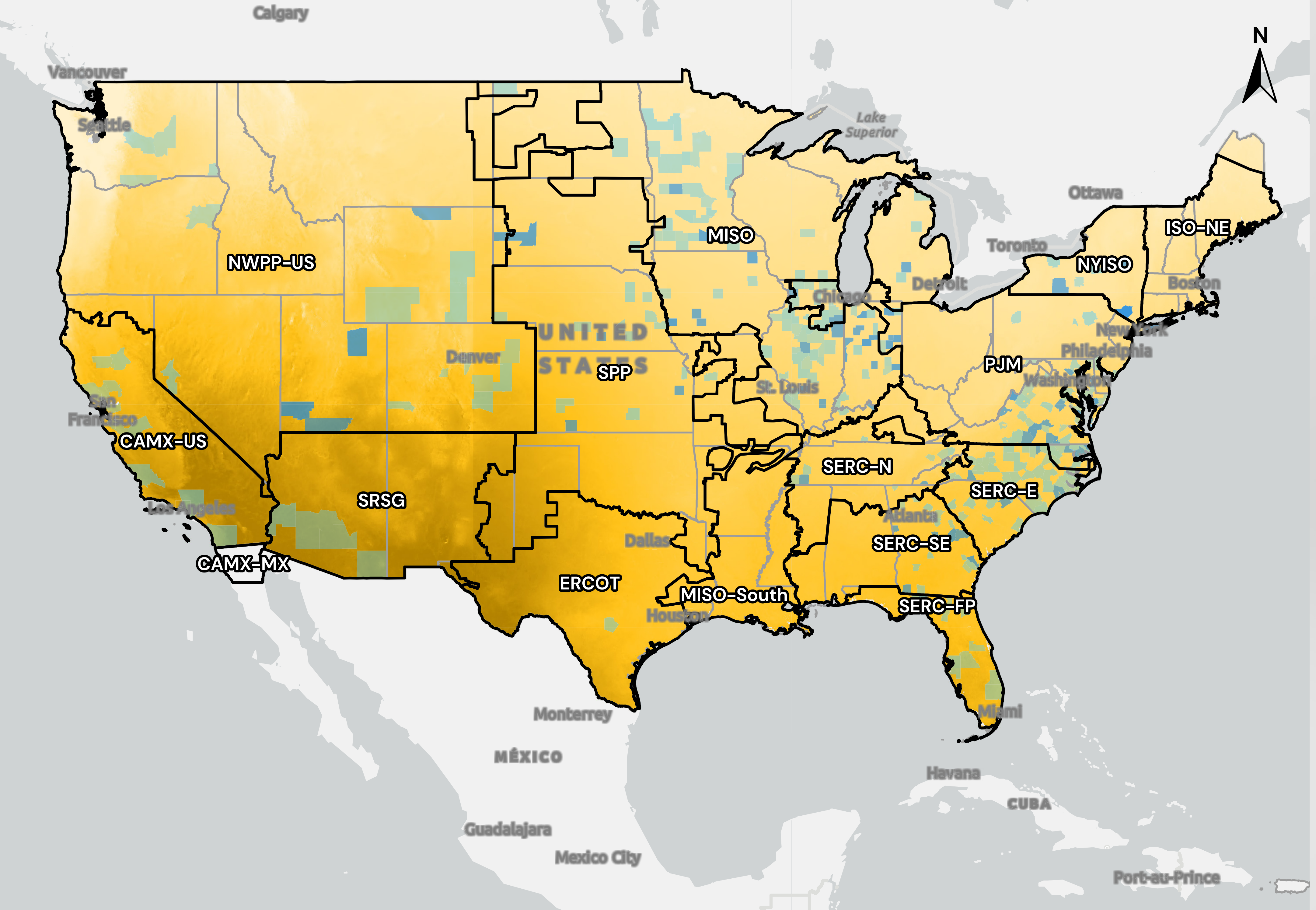
Wind ordinances and wind resource potential



Wind ordinance Some restrictions Multiple restrictions

Average wind speed (elevation 10–m to 200–m) m/s 1.25 14.7

Solar ordinances and solar resource potential



Solar ordinance Some restrictions Multiple restrictions

Global horizontal irradiance kWh/m^2/Day 2.76 6.17

Compiled by ICF using NREL datasets

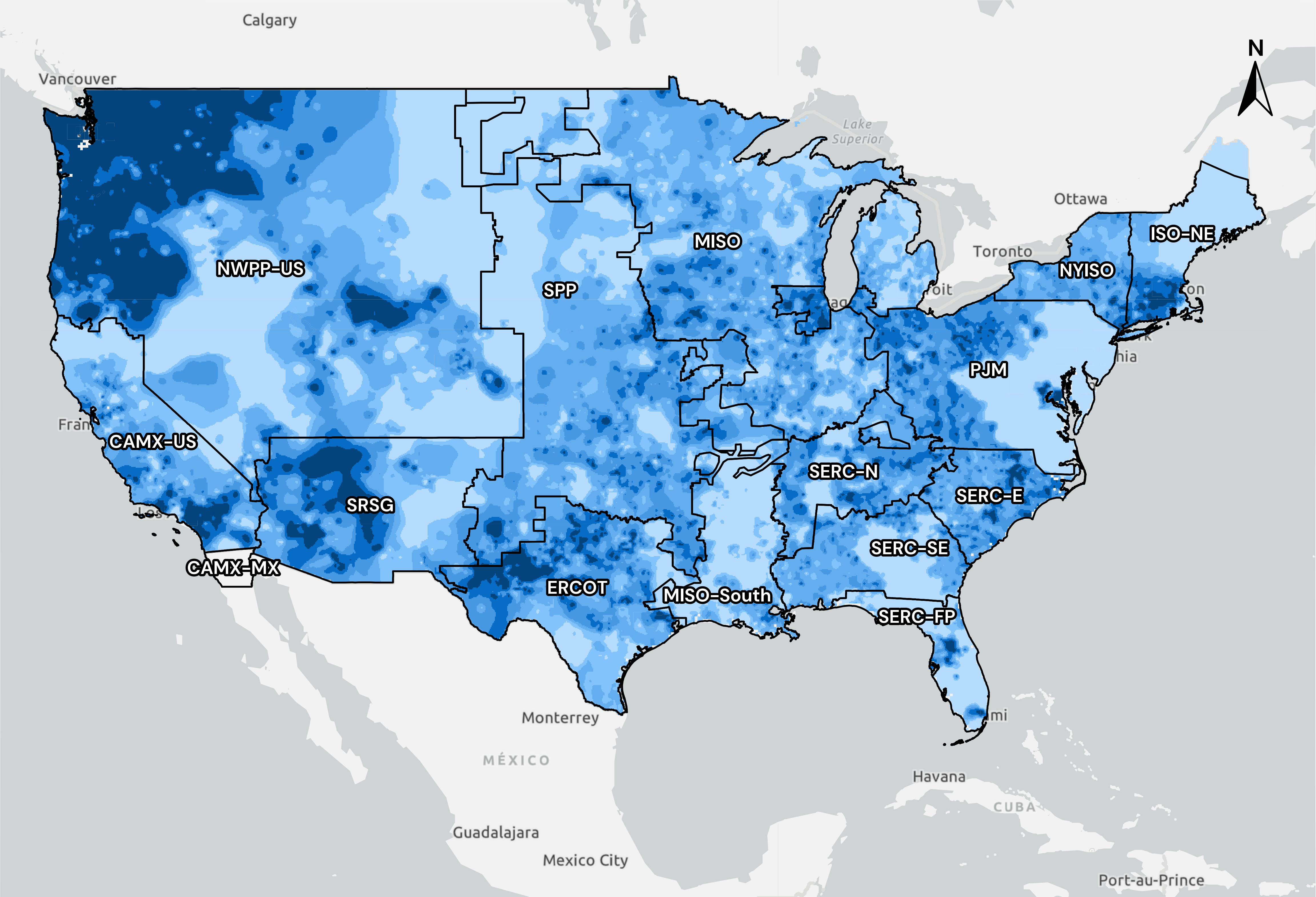
Transmission and distribution grid constraints

Most regional electric grids aren't built to meet a surge in demand.

Regardless of how many new power plants are built, the electricity won't get very far if grid infrastructure isn't improved to accept an injection of more electricity.

As seen in Figure 5, there are several areas where the grid's ability to accept new supply is particularly constrained, including the Mid-Atlantic, parts of New England and the Southeast, and the Upper Midwest, among other regions.

Figure 5: Available grid injection capacity through 2027/2028



Injection capacity (MW): 0 - 50, 50 - 100, 100 - 200, 200 - 300, 300 - 400, 400 - 500

Wholesale Market	Average Injection Capacity (MW)
CAISO	171
ERCOT	246
ISONE	244
MISO	53
NYISO	240
PJM	179
Southeast	176
SPP	176
WECC	292
U.S-wide	**189**

Source: Compiled by ICF using EnergyInsite Reference Case Outlook

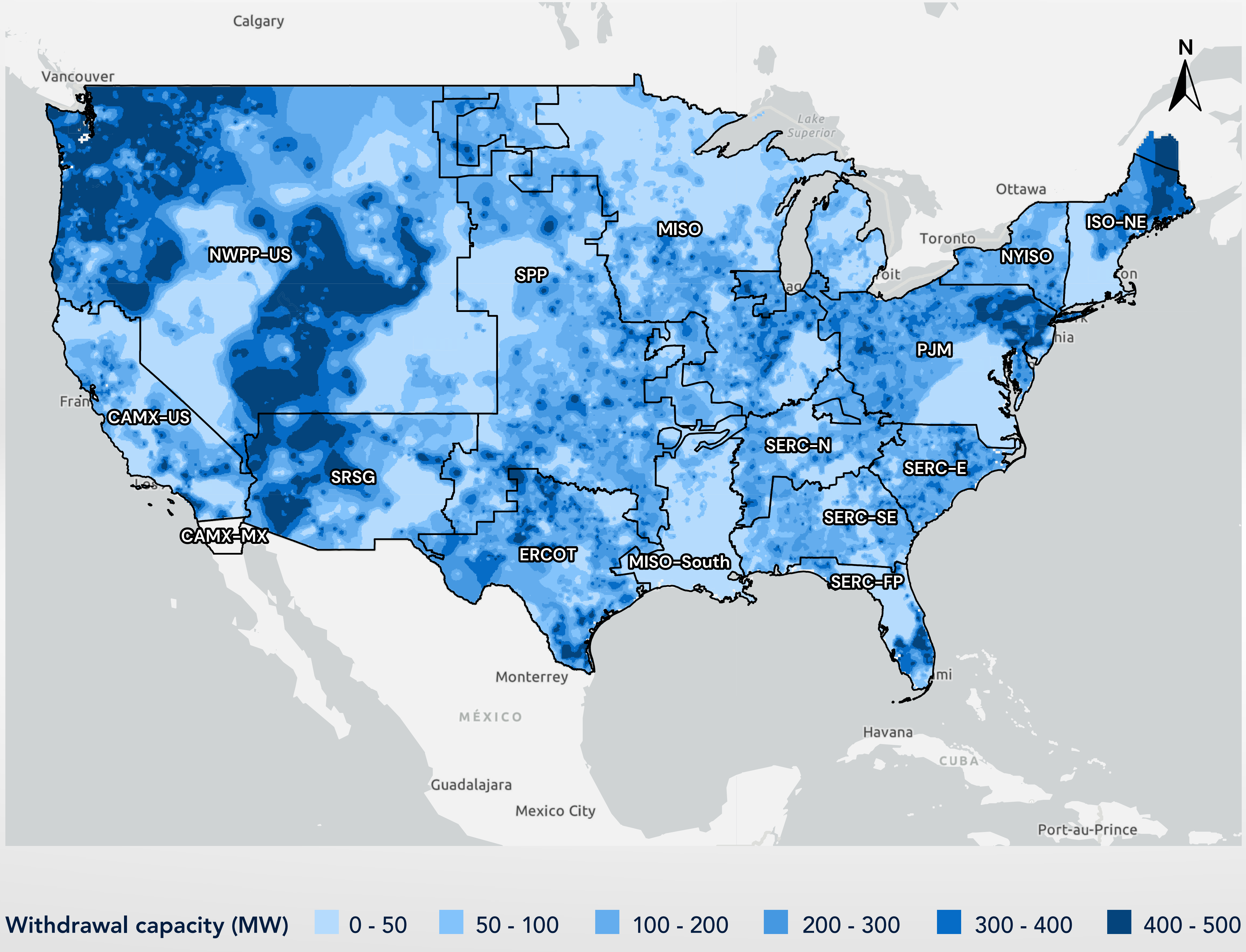
Even if the transmission grid can accommodate an injection of electricity from new power plants, there must also be adequate infrastructure to deliver that electricity to customers through the distribution grid.

Known as withdrawal capacity, Figure 6 reveals that many regions of the grid will have limited ability to discharge new electricity to customers through 2027/2028.[3]

That reality is a particular challenge for areas projected to see high peak demand growth, such as Northern Virginia and parts of Texas. Transmission and distribution grid constraints in those areas only make it more challenging to meet the growing demand.

[3] *ICF assesses available grid capacity as part of its EnergyInsite platform. The grid capacity assessment was done using the PowerGEM TARA tool. This report includes the latest snapshot for each region, which is 2027 for some regions and 2028 for others. See [| Renewable Energy Siting Platform | ICF]*

Figure 6: Available electric grid withdrawal capacity across U.S. through 2027/2028



Wholesale Market	Available withdrawal capacity (MW)
CAISO	130
ERCOT	170
ISONE	60
MISO	31
NYISO	200
PJM	199
Southeast	143
SPP	150
WECC	257
U.S-wide	**153**

Source: Source: ICF

The impacts of demand growth

Will demand growth and supply constraints cause the U.S. to run short on electricity? It's unlikely. However, rapid demand growth makes it more challenging to balance three pillars of electricity service—delivering clean, reliable, affordable electricity.

Clean

Electricity supply constraints and increased demand growth rates complicate decarbonization efforts. Utilities might need to delay retirements of fossil fuel plants to meet new demand, driving up emissions and making U.S. decarbonization goals harder to reach.

Reliable

Without additional power from clean sources or fossil fuels, the levels of reliable power currently available across the country will fall as the margin between how much electricity can be generated and what customers demand shrinks.

Affordable

With enough investment, the U.S. can make major upgrades to the grid and install vast amounts of renewable energy, meeting demand growth while decarbonizing the grid. Americans will likely pay higher utility rates, taxes to pay for federal and state subsidies, or both.

Following are a few ways rising demand creates friction between the imperative for electricity to be clean, reliable, and affordable.

Fossil fuel plant retirement delays

Power plant operators plan to retire 5.2 GW of generating capacity in 2024, a 62% decrease from 2023 when 13.5 GW was retired and the least in any year since 2008, according to the U.S. Energy Information Administration (EIA).[4] Only 2.3 GW of coal capacity is scheduled to retire in 2024, compared to 22.3 GW that was retired in 2022 and 2023.

This slowdown in fossil plant retirements, which delays the clean energy transition, is primarily due to reliability concerns. For example, in early 2024, PJM asked Talen Energy to delay the retirement of 844 MW of fossil-fueled generating capacity in Maryland for three years to ensure reliability.[5]

[4] *Retirements of U.S. electric generating capacity to slow in 2024, EIA*

[5] *US grid operator PJM asks Talen Energy to postpone fossil fuel plant retirements, Reuters.*

Reserve margin percentage point difference

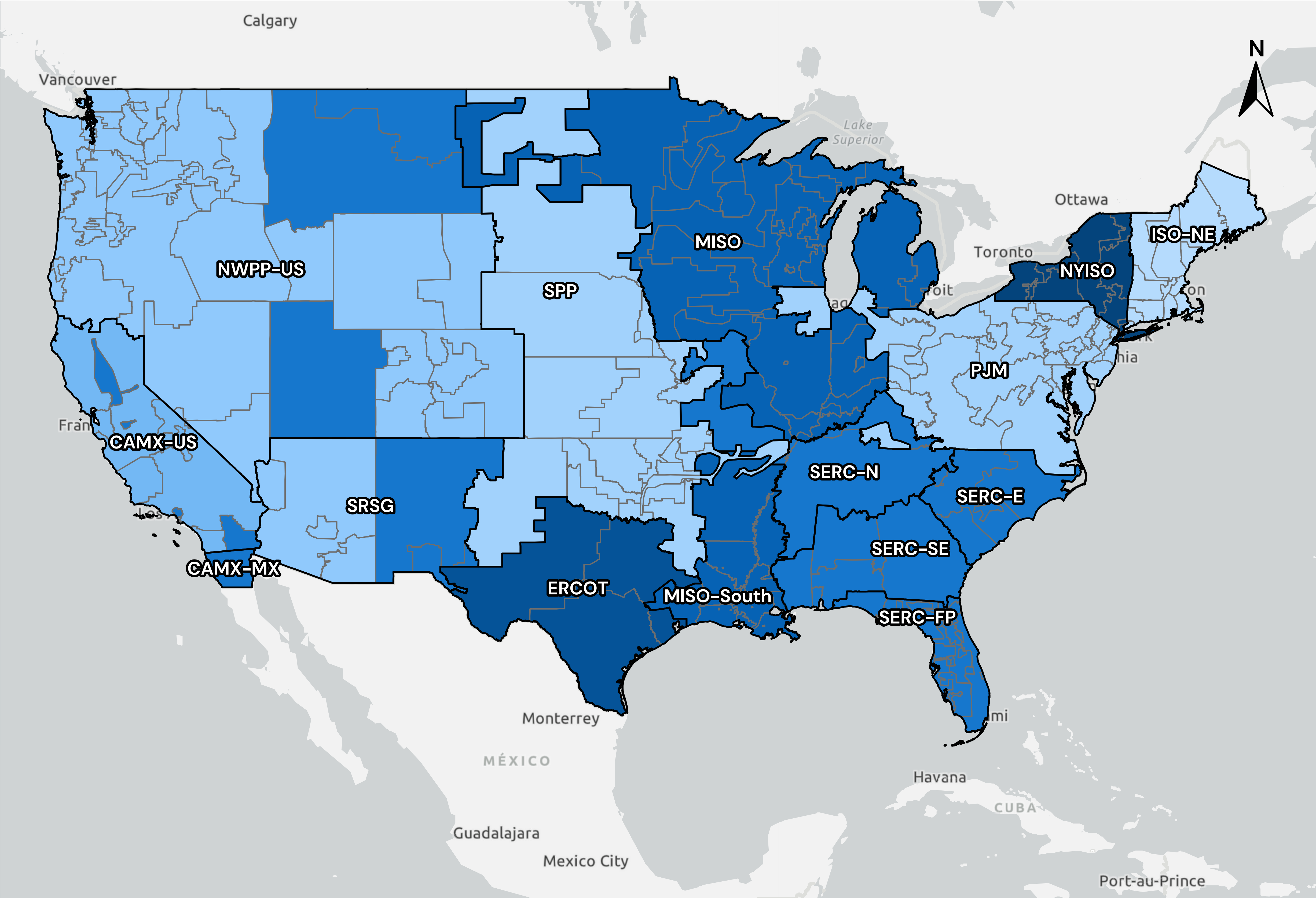
The combination of growing peak electricity demand and the constraints to deliver additional supply will shrink reserve margins—the percentage of surplus electricity available beyond peak demand. Low reserve margins are a risk to reliability.

Figure 7 illustrates that reserve margins are expected to decrease in much of the country from 2024 to 2028, with the PJM, WECC, SPP, and ISO-NE regions expected to see the sharpest drops.

PJM's reserve margin is expected to contract by 6.8%, dropping to 13.8% by 2028. The contraction reflects expectations for a large increase in demand and limited new generation supply, due largely to interconnection queue delays.

As the grid relies on more intermittent renewables to meet peak electric demands that are highly sensitive to extreme weather, higher reserve margins may be needed to maintain electricity reliability. For example, a hot day with little wind across Texas could lead to high peak demand with thousands of megawatts of wind capacity offline.

Figure 7: Projected reserve margins trends 2024-2028



Change in reserve margin (percentage point difference)

<-6 | -6 – -4 | -4 – -2 | -2 – -1 | -1 – -0.5

-0.5 – 0 | 0 – 1 | 1 – 2 | >2

Source: Compiled by ICF using Base Case outlook for individual wholesale markets

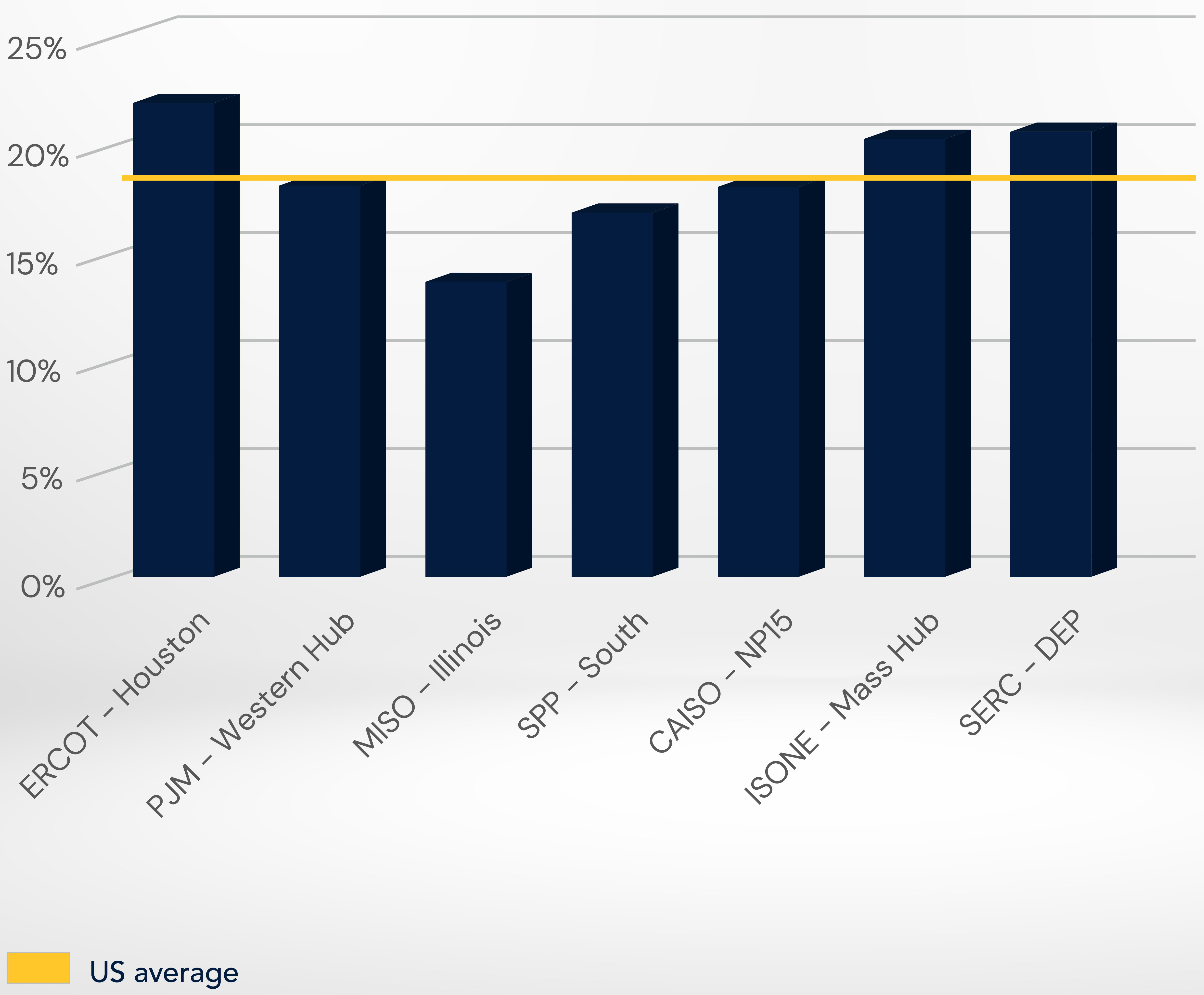
Rising energy prices

The wholesale prices that many utilities pay for electricity are projected to increase by an average of 19% between 2025 to 2028. Distribution costs are also expected to rise, resulting in an increasing cost of electricity for customers.

Some regions will experience higher price increases than others. The ERCOT region serving Texas could experience a 22% increase in wholesale energy prices, while the adjacent MISO region serving the Midwest and much of the South is expected to experience a 14% increase.

> **The wholesale prices that many utilities pay for electricity are projected to increase by an average of 19% between 2025 to 2028.**

Figure 8: Average percentage change in wholesale electricity prices due to demand increase (2025-2028)



Source: ICF

Key recommendations for utilities

Utilities face significant challenges as the industry transitions toward clean, reliable, and affordable electricity, including the need to support massive electrification of the building and transportation sectors, meet surging demand, and build more clean energy generation.

This is a tall order. Major upgrades to the transmission and distribution grid, new renewable energy, and advanced means to manage customer electricity use are needed. Utility customer programs—a diverse mix of initiatives to help customers reduce their electricity use, shift electricity use away from times of peak demand, use more clean energy, electrify transportation and building energy use, and meet many other energy goals—will be critical to success. An unprecedented level of coordination between utility planners and customer program leaders is needed. Those utility leaders will also need to engage with policymakers, regulators, and other stakeholders.

When considering these factors, utilities can plan for and locate clean energy resources – utility-scale and distributed – where they can provide the greatest benefit given regional and local constraints.

1

Create more sophisticated and integrated system planning.

Utilities should establish more robust planning processes that capture the continuum of the electric system starting from electricity generation all the way to the customer. This requires an integrated approach across all asset classes, including generation, transmission, distribution, distributed energy resources (DERs), conservation, and load management. This will equip utilities to consider long term investment strategies that enhance grid reliability, resilience, resource adequacy, and operational efficiency by creating a more diverse mix of resources and allowing greater system-wide flexibility and responsiveness at a lower cost to customers.

Further, by considering operational aspects in an integrated planning environment, increased resilience and customer benefits can be achieved. For example enhanced controls and systems on the distribution networks may help avoid or improve recovery time from faults and outages.

2

Identify ideal locations for renewable energy projects.

Utilities are working to support the addition of more clean energy and to upgrade the transmission grid. But given the constraints outlined in this report, they'll need to find new and better ways to navigate the challenges.

New technology platforms, like EnergyInsite, can identify cost-effective solutions to meet energy demand and supply challenges. Utilities can screen ideal locations for additional renewable energy projects by assessing:

- Land availability
- Grid capacity
- Future power prices and arbitrage opportunities
- Government incentives
- Renewable energy resource potential
- Local queued projects
- Environmental permitting

When considering these factors holistically, utilities can locate clean energy projects in ideal locations.

3

Evolve the distribution grid.

Utilities will need to consider new upgrades to the distribution grid to advance electrification and greater DER adoption. Targeted deployment of DER programs such as dual-use provisions that allow for co-benefits to customers and utilities be realized should be considered to offset traditional distribution investments. For example, a utility may finance backup storage for a customer that the utility could use during periods of high demand.

Utilities will need to have greater visibility, stability, and control of two-way power flow from these DERs to maintain reliability.

Distribution grid upgrades will impact customer electricity rates and utility revenue, so utilities will need to consider how to recover costs while continuing to deliver affordable electricity to customers. Innovative tariffs, incentives, and subsidies can help manage these costs.

4

Plan and implement next-gen customer programs.

Traditional energy efficiency strategies have focused on energy conservation, measured by avoided kilowatt-hours. These energy efficiency programs will play an increased role in reducing baseload electricity demand. But they'll need to be complemented by new, more active load management programs that balance intermittent renewable electricity closest to the source of the demand.

A new generation of customer programs that is already emerging will leverage and orchestrate grid-edge technology—including rooftop solar, electric vehicle charging stations, battery energy storage, and virtual power plants.

Demand response and other load management programs will become increasingly important to manage the dynamic grid. Utilities should prioritize creative marketing and innovative incentives to reduce the first-cost barrier of clean energy technologies and motivate customers to opt-in to these new programs, which could otherwise seem new and intimidating.

SMECO's next-gen utility program

Southern Maryland Electric Cooperative (SMECO) continues to partner with ICF to reduce annual and peak energy for its members. By doing so during times of high energy, SMECO can decrease the use of less efficient and more expensive power sources, which benefits the environment and helps keep energy costs low for all of the Cooperative's members.

Through SMECO's SmartTemp program, the Cooperative leverages ICF's advanced data analytics and machine learning to control members' smart thermostats, making customized adjustments to the temperature on days of high energy demand. This program delivers 2.7% to 4% more energy savings at the meter than traditional demand response treatments while maintaining higher customer satisfaction and comfort.

5

Leverage data and artificial intelligence.

Advanced meter infrastructure data and other data sources can be uploaded to the cloud and managed with emerging AI platforms. These platforms offer new capabilities that are tailor-made for planning, measuring, and optimizing customer programs, including:

- Identifying and forecasting the most congested locations on the electric grid from 1 minute to 30 years in future. Using generative AI, utilities can even query their grid with questions, such as, "What are the top 10 locations in my service territory with the highest demand for electricity?" This works at the substation level or even the building level.
- Predicting cost-effective measures to reduce demand in a specific location. Utilities can now create a digital twin of one part of the grid to predict the best incentives and programs for customers in that area.
- Actively managing customers' energy use, via resources like smart thermostats, in real time to tamp down electricity demand before it causes reliability issues. Using AI to autonomously turn up customer thermostats by a few degrees in the afternoon can help reduce peak energy demand during a heat wave.
- Monitoring and optimizing programs in real-time by feeding program results back into the AI model to make it smarter.

This data management and analysis also creates opportunities for utilities and regulators to measure and define monetary value for program performance.

6

Engage with regulators.

Utilities are uniquely positioned to lead the charge on clean electricity. However, regulators and policymakers also need to recognize the complexity of this transformation.

The design, implementation, and evaluation of customer programs must evolve to incorporate broader distribution system impacts, locational benefits, and the integration of DERs, advanced demand management tactics, and more.

All this change will require engagement with utility regulators across a variety of issues, including:

- Finding ways to incentivize investments in supply and demand resources, including innovation, and research and development.
- Allowing tariffs that enable fair recovery of grid maintenance and investment costs, based on usage by different kinds of customer groups.
- Considering alternatives for cost recovery and return on investment for non-traditional investments.
- Balancing investment risks of new technologies with safe, secure, reliable, and affordable electricity. Performance-based rate structures, market participation, and other solutions should all be considered.

SIGHTLINE®

ICF's AI-powered platform, Sightline, offers utilities end-to-end program planning and implementation at the tip of their fingers.

Conclusion

An era of rapid energy demand growth, combined with constraints hindering transmission and generation solutions, is a perfect storm of challenges for utilities in the midst of orchestrating a massive clean energy transition.

New generation, upgraded transmission and distribution systems, and expanded demand-side management—empowered by customer programs—will all be part of the solution.

However, before utility planners and customer program leaders can piece together a strategy with the right mix of solutions, they need to work together to break down silos and invest in cutting-edge data, research, and planning resources. Together, they can achieve an energy transition characterized by a clean, reliable, and affordable future.

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