North Carolina Energy Policy Task Force

Secretary Reid Wilson
CO-CHAIR

Representative Kyle Hall
CO-CHAIR

December 02, 2025

Welcome and Opening Remarks

Representative Kyle Hall
CO-CHAIR

Secretary Reid Wilson
CO-CHAIR

North Carolina Energy
Policy Task Force

Call to Order & Roll Call

Sec. Wilson	**Call to Order**
Members	**Roll Call**

Conflict of Interest Policy

In accordance with the **State Government Ethics Act**, it is the duty of every Task Force member to avoid both conflicts of interest and the appearance of conflicts of interest.

If any member has any known conflict of interest or is aware of facts that might create the appearance of such conflict with respect to any matters coming before the Taskforce today, please identify the conflict or facts that might create the appearance of conflict to ensure that any inappropriate participation in that matter be avoided.

If at any time, any new matter raises a conflict during the meeting, please be sure to identify it at that time.

Public Records Policy

N.C. GEN. STAT. §132-1(b): "Public records and public information compiled by the agencies of North Carolina Government of it subdivisions are the property of the people"

What is public record?

- Any type of document "made or receive pursuant to law or ordinance in connection with the transaction of public business…"
- "Commissions and committee members," including members of this task force are included
- Includes text messages, emails, instant messages regard state business on either public or private devices or accounts

Presentations

- Luke Wilson, Chief Policy Officer, Indiana Office of Energy Development

- Commissioner Kelsey Bagot, Virginia State Corporation Commission

Indiana's Energy Landscape

INDIANA OFFICE OF ENERGY DEVELOPMENT
Luke Wilson, Chief Policy Officer

11/19/2025

OUTLINE

- Indiana’s Landscape
- Energy Prices & Load Growth
- Indiana’s Actions
- Final Thoughts

Indiana's Regulatory Landscape

- Indiana has a similar regulatory structure compared to North Carolina.
  - Vertically integrated utilities.
  - State utility commissions that set rates and charges for regulated utilities
  - State utility commissions that enforce resource adequacy requirements (i.e. providing safe and reliable power)
  - Utilities submit integrated resource plans (IRPs) demonstrating how they plan to meet their forecasted demand over the next 20 years.
    - Want lowest cost reasonably possible while maintaining flexibility.
  - Difference: Indiana utilities participate in RTOs (MISO or PJM)

Indiana’s Generation Fuel Mix

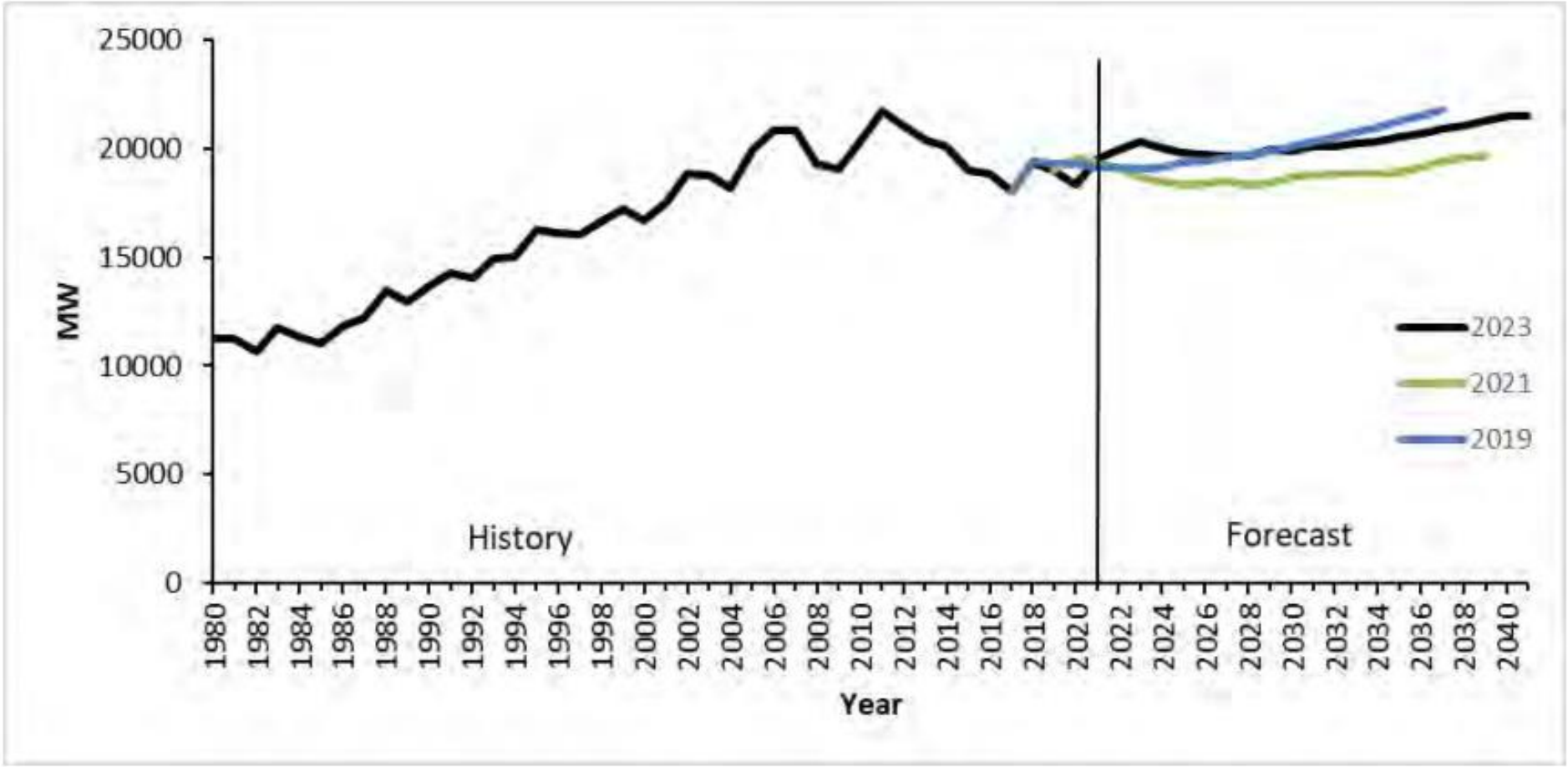
Indiana’s Generation Fuel Mix

Resource	2007	2015	2024	Change
Coal	85.5%	68.5%	39.6%	-45.9%
Natural Gas	2.8%	14.2%	34.0%	31.2%
Nuclear	9.0%	9.9%	12.0%	3%
Wind	0%	4.0%	9.2%	9.2%
Solar	0%	0.1%	1.8%	1.8%
Other (e.g. hydro)	2.7%	3.3%	3.3%	0.6%

ENERGY PRICES & LOAD GROWTH

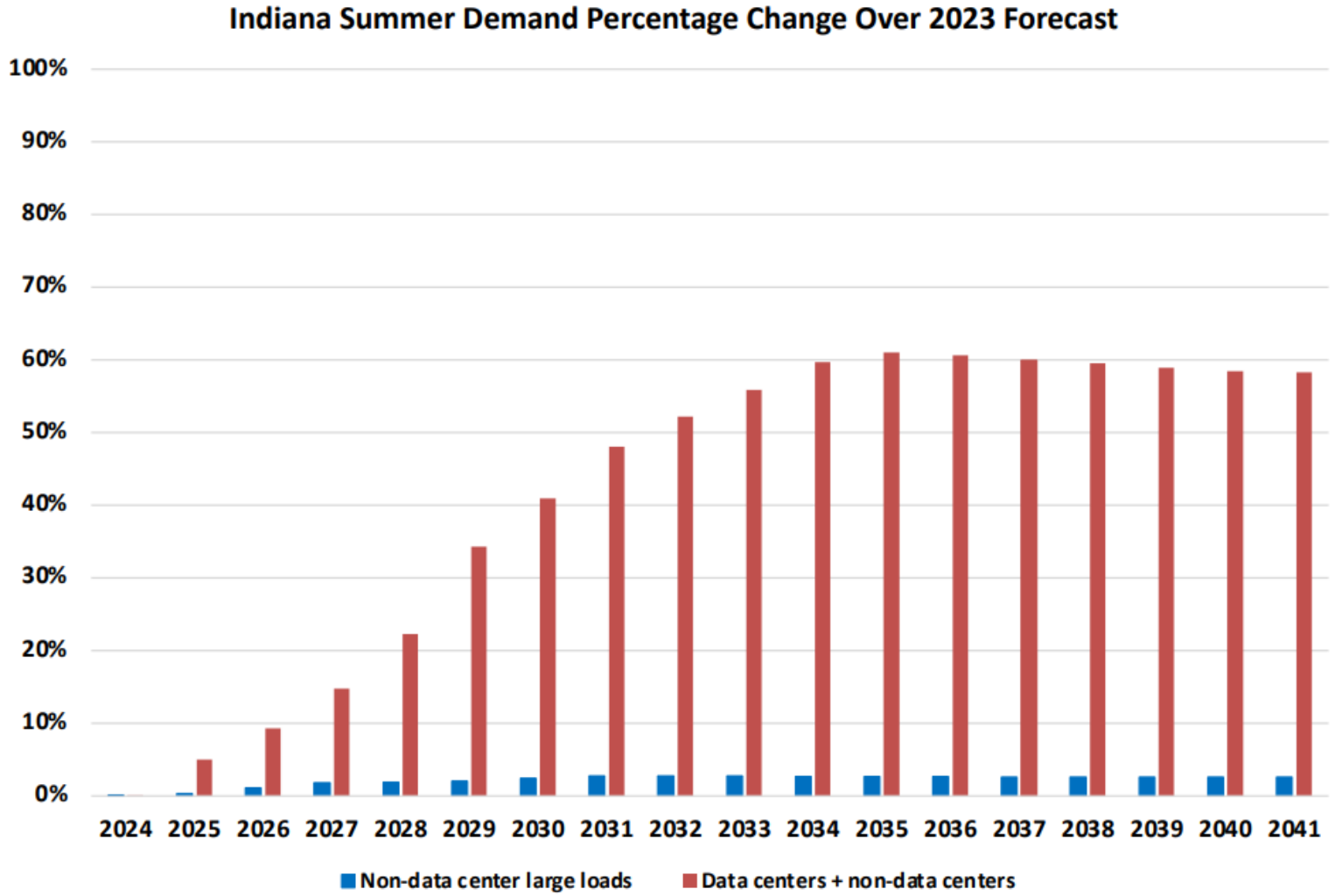
Indiana Peak Load Growth

Figure 3-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Source: SUFG 2023 Report

Updated Load Growth



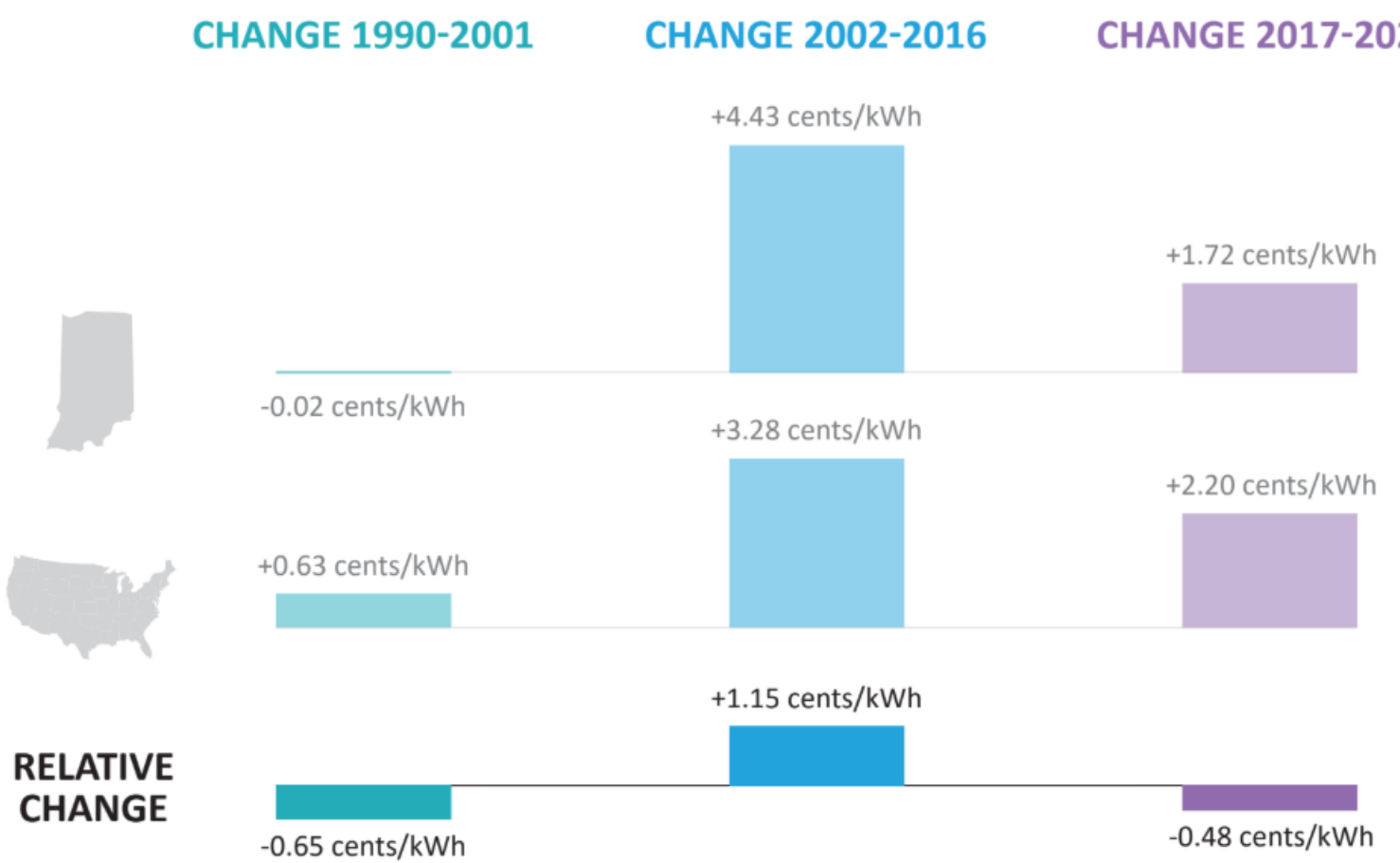
Source: SUFG 2025 Report Preview

ENERGY PRICES

- Indiana's average electric price rank compared to other states

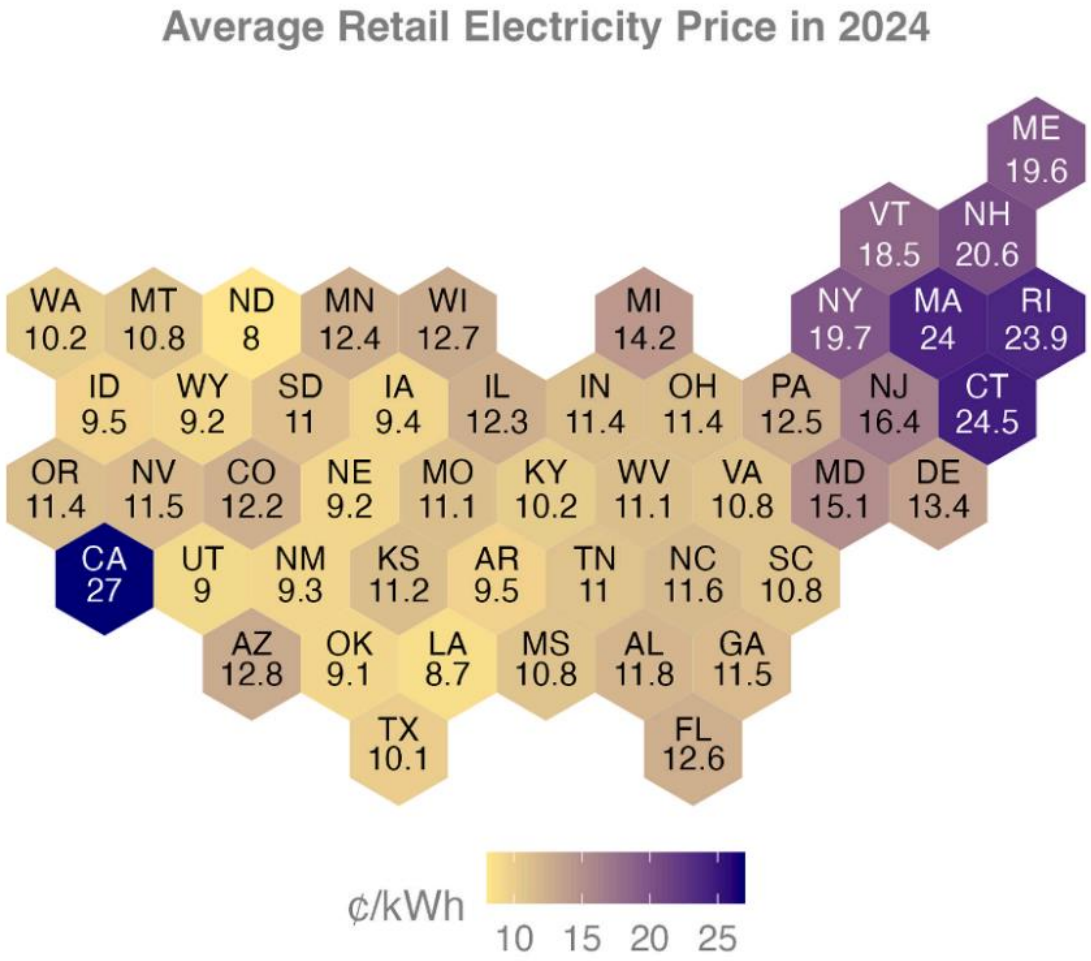
Source: IURC

ENERGY PRICES



Source: IURC

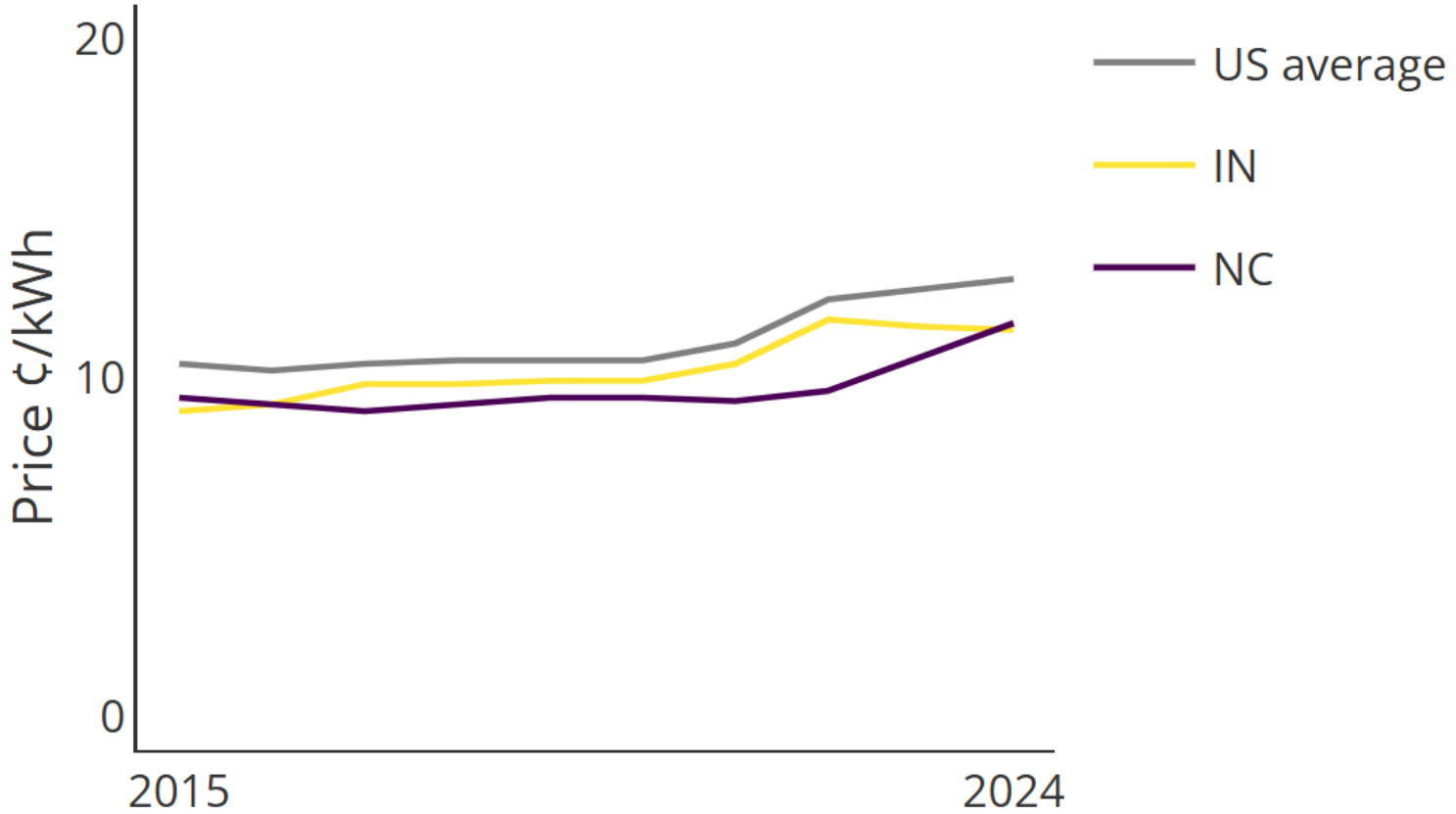
ENERGY PRICES



Source: LBNL & Brattle 2025 Cost Review Report

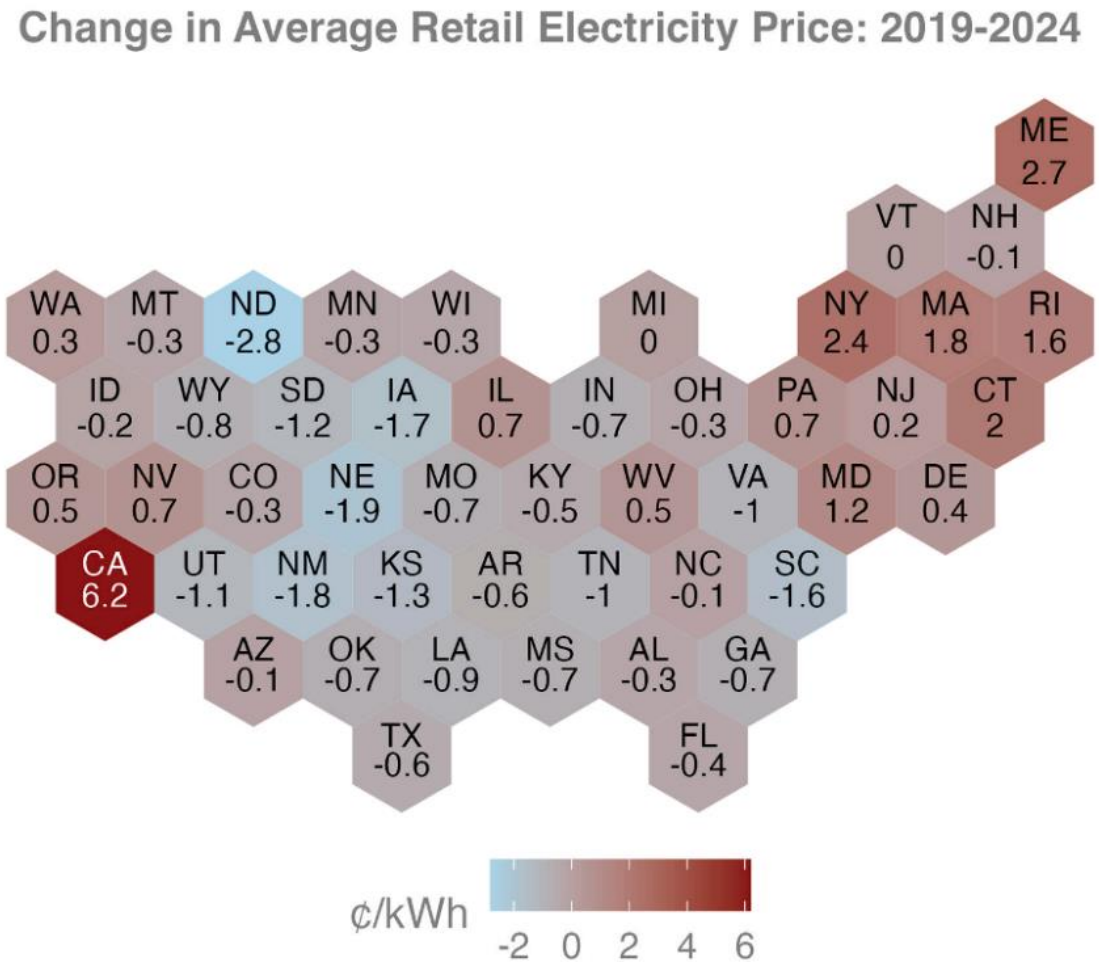
ENERGY PRICES

Average Retail Electricity Prices



Source: LBNL & Brattle 2025 Cost Review Report

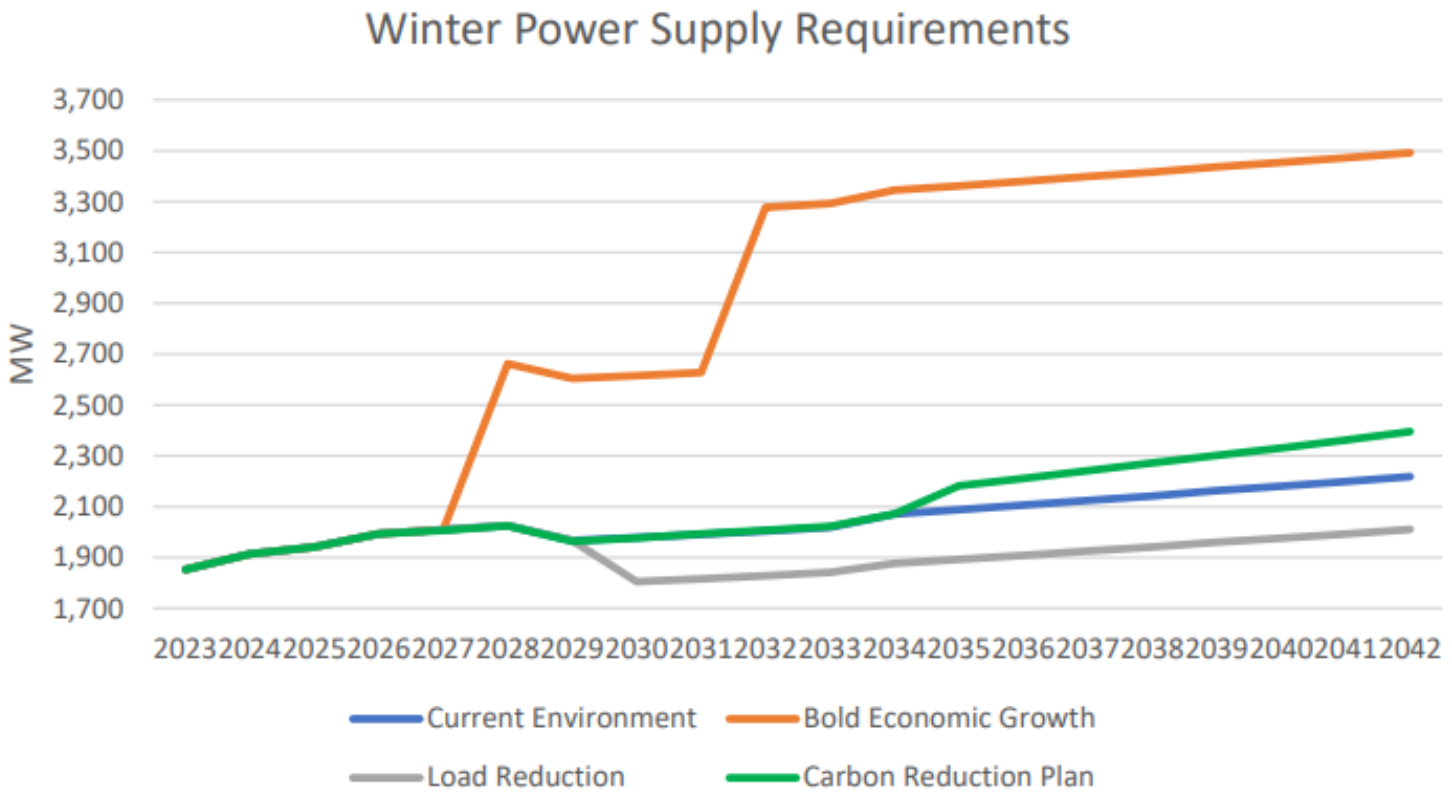
ENERGY PRICES



Source: LBNL & Brattle 2025 Cost Review Report

Indiana Utilities Forecasting Spiky Growth

- Wabash Valley Power Alliance (WVPA) 2023 IRP



Indiana Utilities Forecasting Spiky Growth

- AES Indiana 2025 IRP

2025 IRP Candidate Portfolios: Cumulative New Installed Capacity through 2035

		DR	EE	Storage	Gas CCGT	Gas Peaking	Solar	Wind
No Data Center Load	Reference Case Portfolio	223	191	100	0	0	0	0
	Gas Infrastructure Portfolio	223	191	100	0	0	0	0
	High Regulatory Portfolio	223	191	120	0	0	25	900
	Stable Markets Portfolio	87	191	0	0	0	0	0
Low Data Center Load (500 MW)	Reference Case Portfolio	218	191	420	0	480	0	0
	Gas Infrastructure Portfolio	218	191	160	700	0	0	0
	High Regulatory Portfolio	223	191	780	0	0	350	1,350
	Stable Markets Portfolio	218	191	120	0	480	50	0
Mid Data Center Load (1,500 MW)	Reference Case Portfolio	200	191	860	700	480	0	0
	Gas Infrastructure Portfolio	223	191	380	1,400	108	50	0
	High Regulatory Portfolio	223	191	1,840	0	0	1,050	2,750
	Stable Markets Portfolio	223	191	720	0	960	100	0
High Data Center Load (2,500 MW)	Reference Case Portfolio	218	191	640	2,100	294	0	0
	Gas Infrastructure Portfolio	223	191	620	2,800	0	25	0
	High Regulatory Portfolio	223	191	2,480	0	480	1,225	2,800
	Stable Markets Portfolio	218	191	960	700	1,440	100	0

What About Indiana?

- Duke Energy Indiana 2024 IRP

Table 3-5: Key Assumptions for Alternate Load Forecast Scenarios

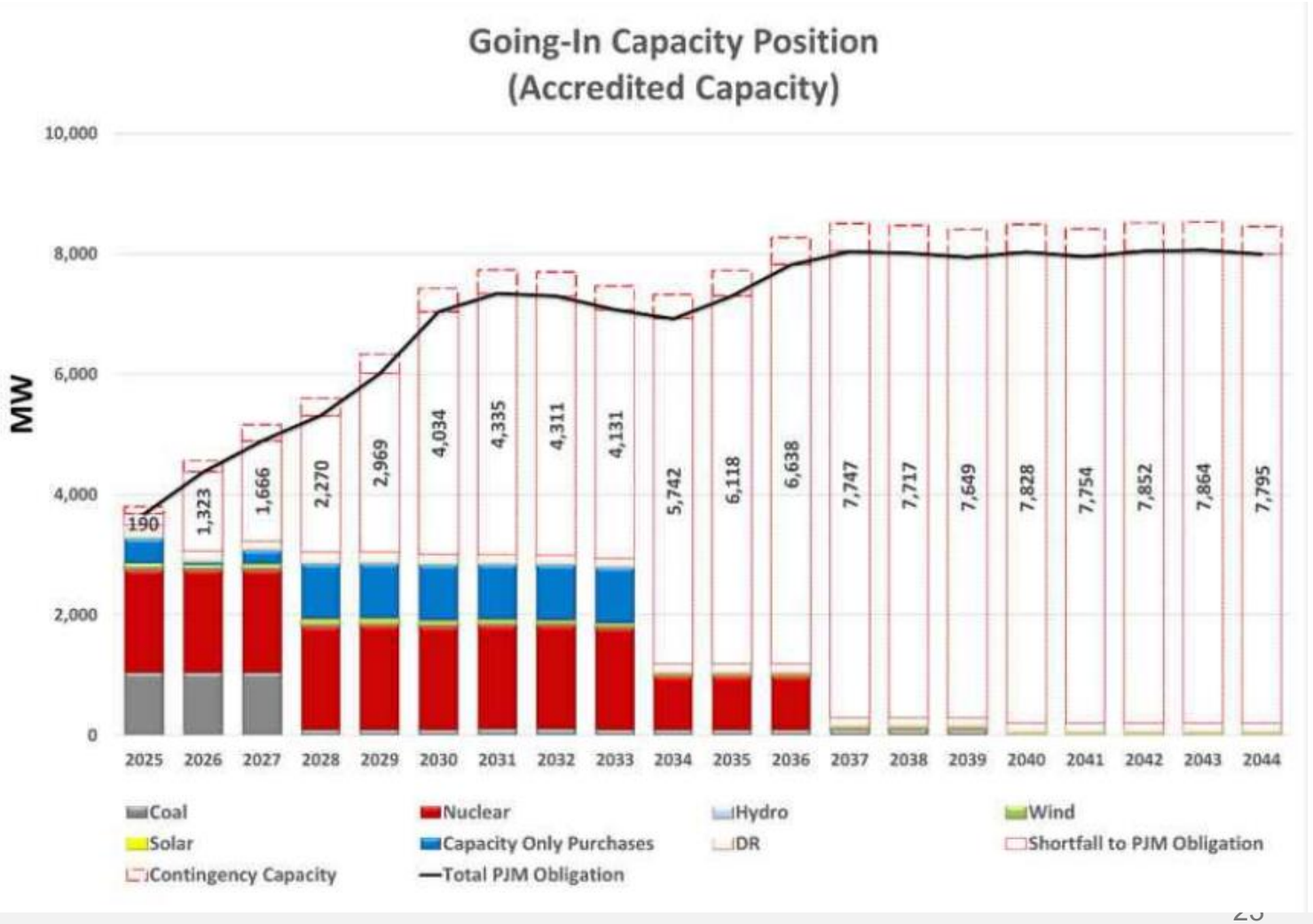
	Economics	Electric Vehicles	Behind-the-Meter Solar	Economic Development[1]
Low	90/10	Low Adoption	High Adoption	Low (25%)
Base	50/50	Base Adoption	Base Adoption	Base (~60%)
High	10/90	High Adoption	Low Adoption	Higher (75%) +500 MW data center[2]

Note 1: Economic development includes projects greater than 20 MW with plans sufficiently advanced such that some level of demand could be anticipated with a reasonable degree of certainty.

Note 2: 500 MW of data center load is assumed in the high case in addition to 75% of announced economic development projects.

Indiana Utilities Forecasting Spiky Growth

- Indiana Michigan Power (I&M) 2024 IRP
  - I&M's peak demand will almost double by 2031.



Indiana Utilities Forecasting Spiky Growth

- NIPSCO's 2024 IRP
  - NIPSCO's peak load will more than double with confirmed data center projects.

Figure 3-42: Projected New Large Load Additions

	2028	2030	2035
IRP Peak Load – Original Reference Case	2,300 MW	2,300 MW	2,500 MW
+New Load Added to All IRP Scenarios	*600 MW*	*1,600 MW*	*2,600 MW*
IRP Peak Load – New Reference Case	**2,900 MW**	**3,900 MW**	**5,100 MW**
+Emerging Load Sensitivity	*2,600 MW*	*4,500 MW*	*6,000 MW*
Total IRP Peak Load with Emerging Load Sensitivity	**5,500 MW**	**8,400 MW**	**11,100 MW**

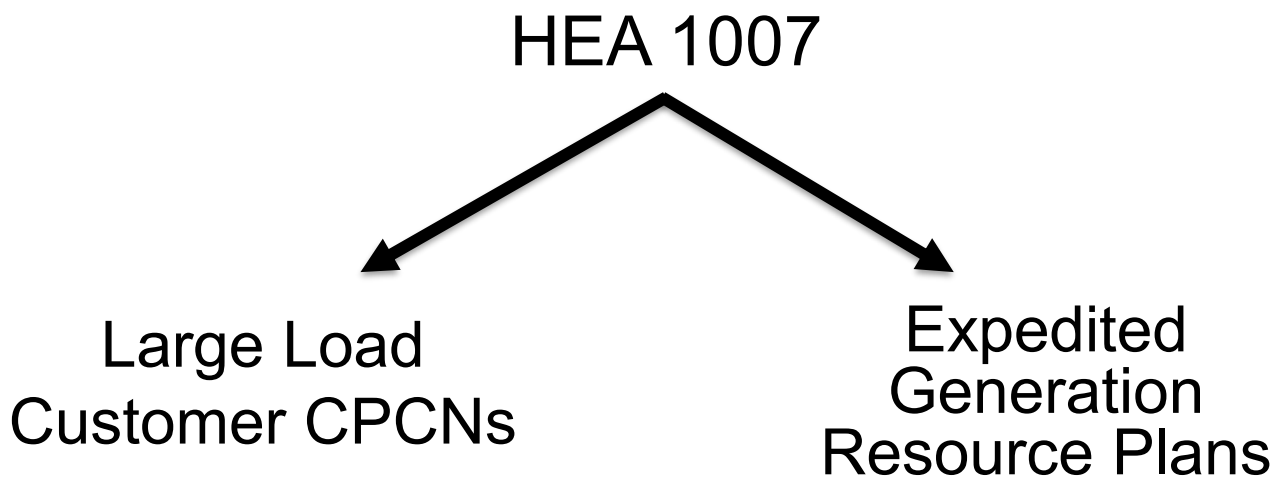
ACCREDITED OR EFFECTIVE CAPACITY

- Morgan Stanley Annual Energy Paper (2023):
  - "…we computed the amount of natural gas that can be disconnected when adding solar and wind to meet another 10% of demand. The result: due to wind and solar intermittency and the need to meet demand and maintain system reliability, **only 10-30 MW of natural gas could be disconnected for every 100 MW of new wind and solar capacity.** These capacity credits decline as more wind and solar are added to the system..."

INDIANA LEGISLATIVE ACTION

HEA 1007-2025 & Dealing with New Large Loads

- How do you ensure that data centers pay their incremental system costs while recognizing the possible benefit they offer to existing ratepayers AND maintain speed to market??



HEA = House Enrolled Act

Large Load Customer CPCNs

- IURC must approve new electric generation builds.
  - Normally through the Certification of Public Convenience & Necessity (CPCN)
  - Regulatory process has a 240-day shot clock.

Large Load Customer CPCNs

- HEA 1007 creates a new expedited (150-day) process to get IURC-approval for new generation meant to serve a large load customer (150MW or greater of demand)
- Pairs specific customers with specific generation projects.
- Customer must commit to covering at least 80% of their project's allocated costs regardless of their in-service time.
  - Customer and utility can agree to a higher amount.

Large Load Customer CPCNs

- The utility can request the large load customer pay a risk premium for the project.
- The utility must demonstrate how the project meets the 5 Pillars policy and protects existing and future ratepayers.
  - Indiana's Five Pillars are affordability, reliability, resiliency, stability, and environmental sustainability.
- IURC shall base its determination on whether the proposal is just, reasonable, and in the public interest.

Expedited Generation Resource (EGR) Plans

- HEA 1007's second pathway to help protect ratepayers while accelerating regulatory processes is the EGR plan.

- The EGR pathway establishes a portfolio approach to serving new large load customers – these customers are increasing the generation needs of the utility to provide safe and reliable service to all customers.

Expedited Generation Resource (EGR) Plans

- For the EGR pathway, the utility must first file an EGR plan, which the IURC has 90 days to review.

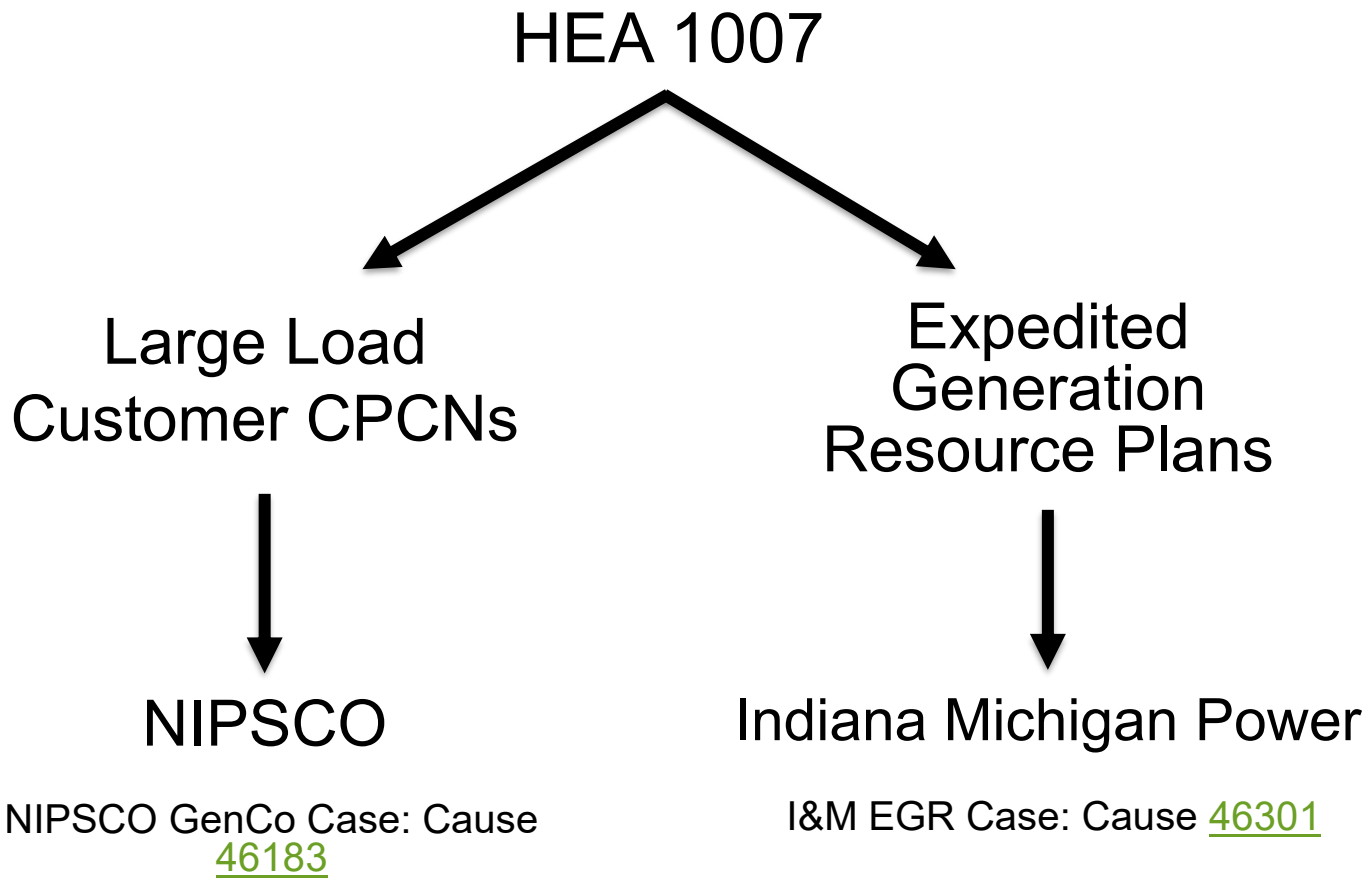
- Think of the EGR plan as a “mini-IRP”.
  - What generation resources make sense from an affordability and reliability perspective to serve my new customer base.
  - Plan out new generation additions and get approval from IURC to go seek out those specific resources in the marketplace.
    - The EGR plan approval is almost like a pre-approved mortgage.

Expedited Generation Resource (EGR) Plans

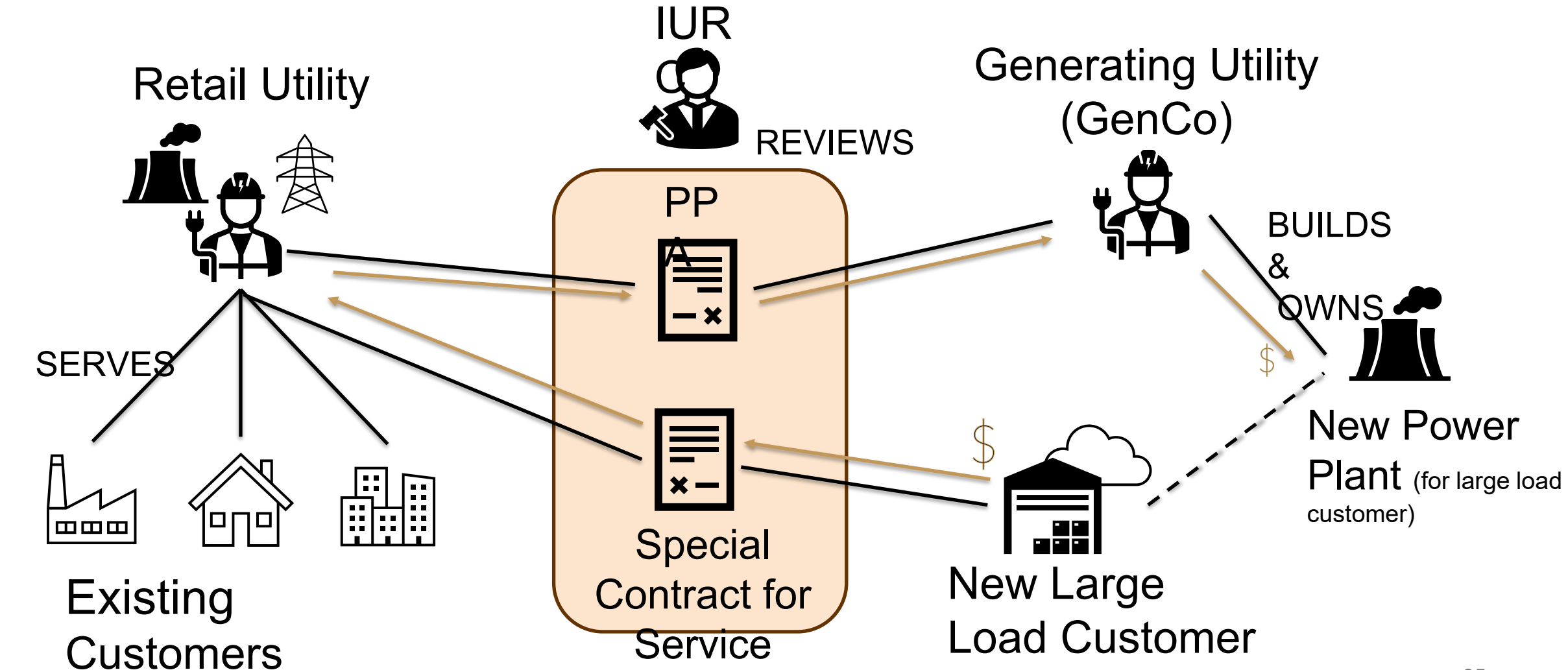
- Once the EGR plan is approved and the utility picks a new resource to build or acquire, the utility files an EGR resource submittal with the IURC.
  - This details the generation type, size, and estimated costs.
  - The IURC has 60 days to review the submittal if it is considered a clean energy project and 120 days if it is not.

- The utility's EGR plan and EGR resource submittal must demonstrate how existing and future ratepayers are protected.

HEA 1007-2025 & Dealing with New Large Loads



HEA 1007-2025 & Dealing with New Large Loads



Recent State Legislative Actions

- Senate Enrolled Act 425-2025
  - Sought to expedite new generation build projects
  - Exempts new generation projects from having to receive local zoning/permits if the project is on an existing/retired generation sites or existing/retired surface or underground mining sites.
    - Does not apply to wind energy or solar energy developments

FOOD FOR THOUGHT

Final Thoughts

- Separate out normal load growth from new large load customers when forecasting.
- Look for ways to expedite building new generation for new large load customers.
  - Growth pays for growth.
  - Protect (and help) existing retail utility customers.
- Ensure utilities are maintaining resource adequacy.

THANK YOU

INDIANA OFFICE OF ENERGY DEVELOPMENT
Luke Wilson, Chief Policy Officer

APPENDIX

Generation Mix

Generation Resources Serving Hoosier Customers

Resource	MW
Coal	10,290
Natural Gas	7,083
Hydro	56
Wind	2,256
Solar	2,665
Biogas	17
Petroleum	48
Cook Nuclear Plant (MI)	1,460
Total	**23,875**

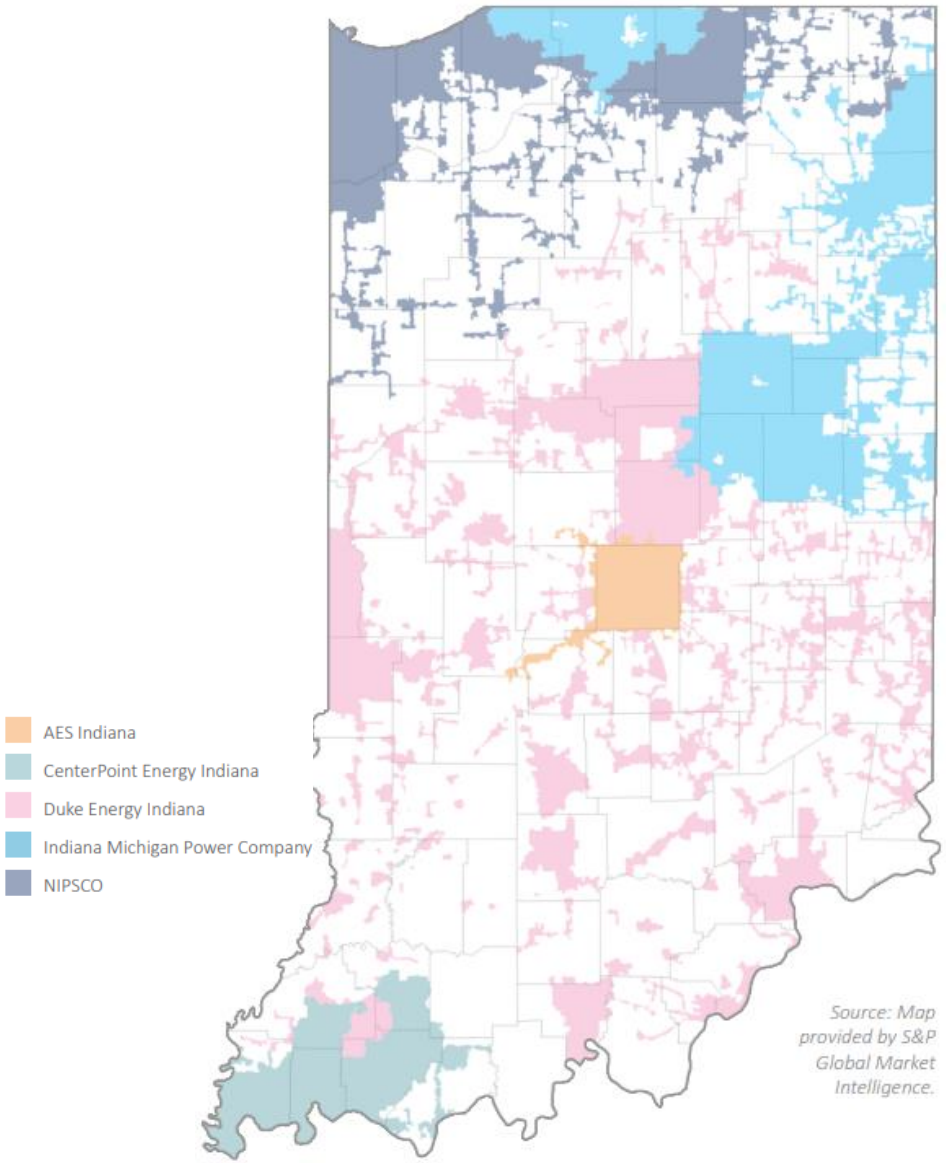
- Generation resources used by retail utilities to serve Hoosiers
  - Nameplate capacity
- Does not include resources below 10MW
- Does not include short-term capacity contracts or power purchase agreements between utilities

Source: IURC 2025 Annual Report

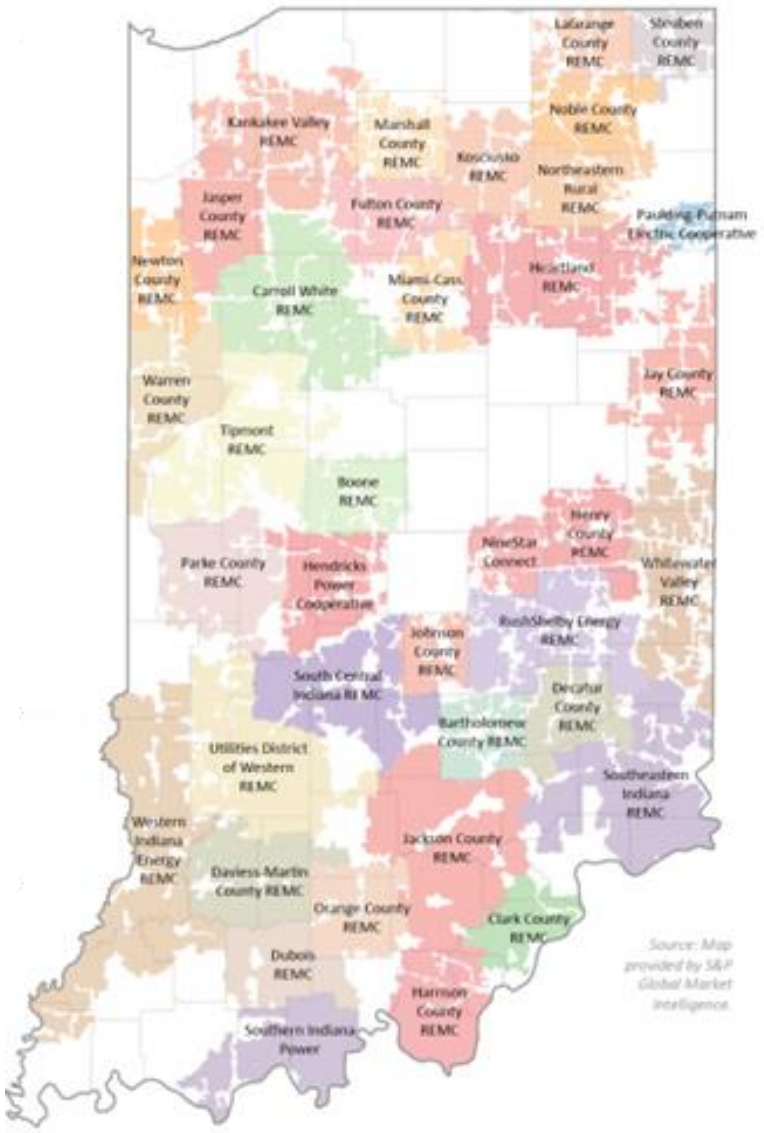
Indiana's Regulatory Landscape

- Indiana electric utilities:
  - 5 investor-owed electric utilities
    - AES Indiana (serving Indianapolis)
    - CenterPoint Energy (serving southwest Indiana)
    - Duke Energy Indiana (largest utility in the state)
    - Indiana Michigan Power (serving parts of northern & eastern Indiana)
    - NIPSCO (serving mainly northwest Indiana (outside Chicago))
  - 79 municipal electric utilities
  - 38 rural electric membership cooperatives

IOU ELECTRIC SERVICE TERRITORIES



INDIANA ELECTRIC COOPERATIVES SERVICE TERRITORIES

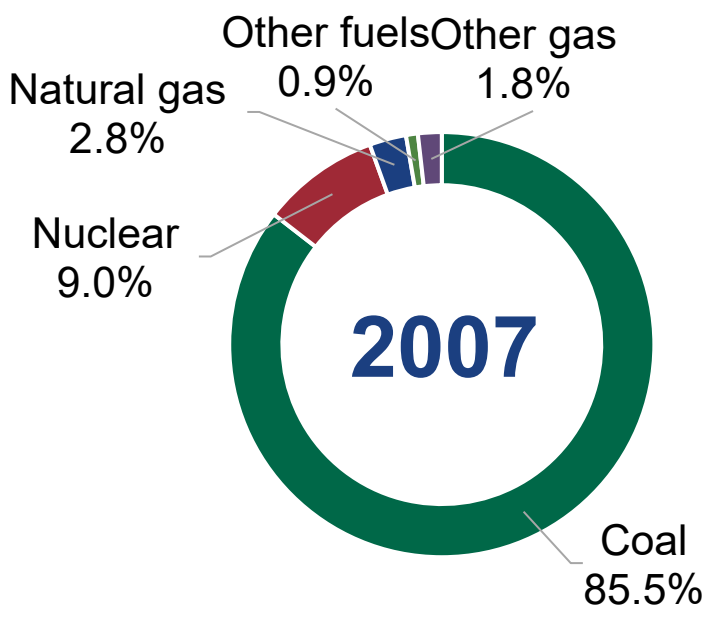


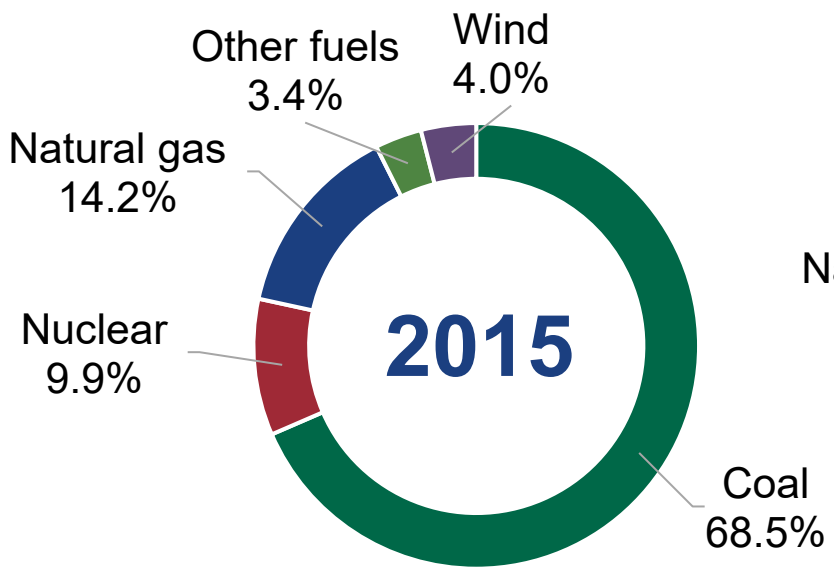
MUNICIPAL ELECTRIC SERVICE TERRITORIES

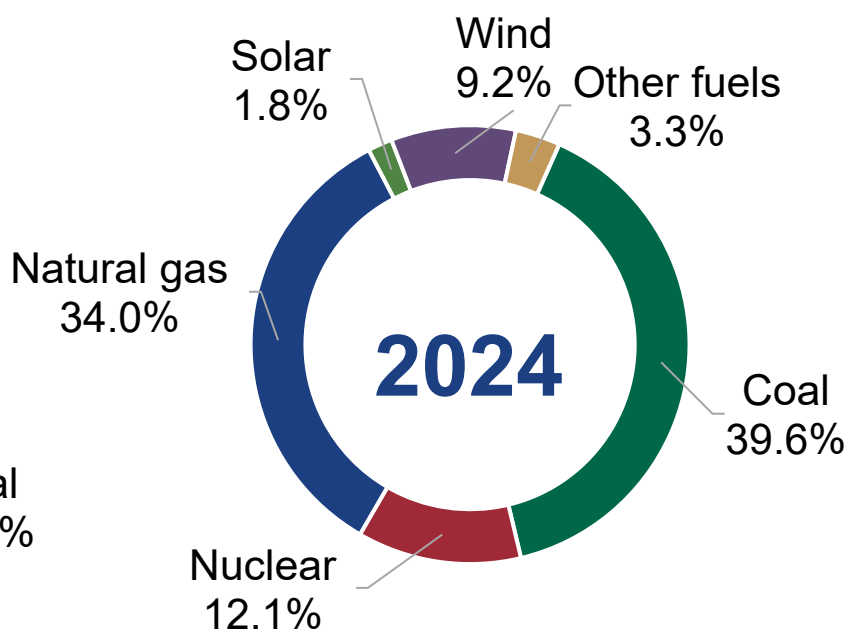
Source: IURC 2025 Annual Report

Generation Mix Transition

Indiana's Generation Fuel Mix







*Numbers are rounded from EIA data

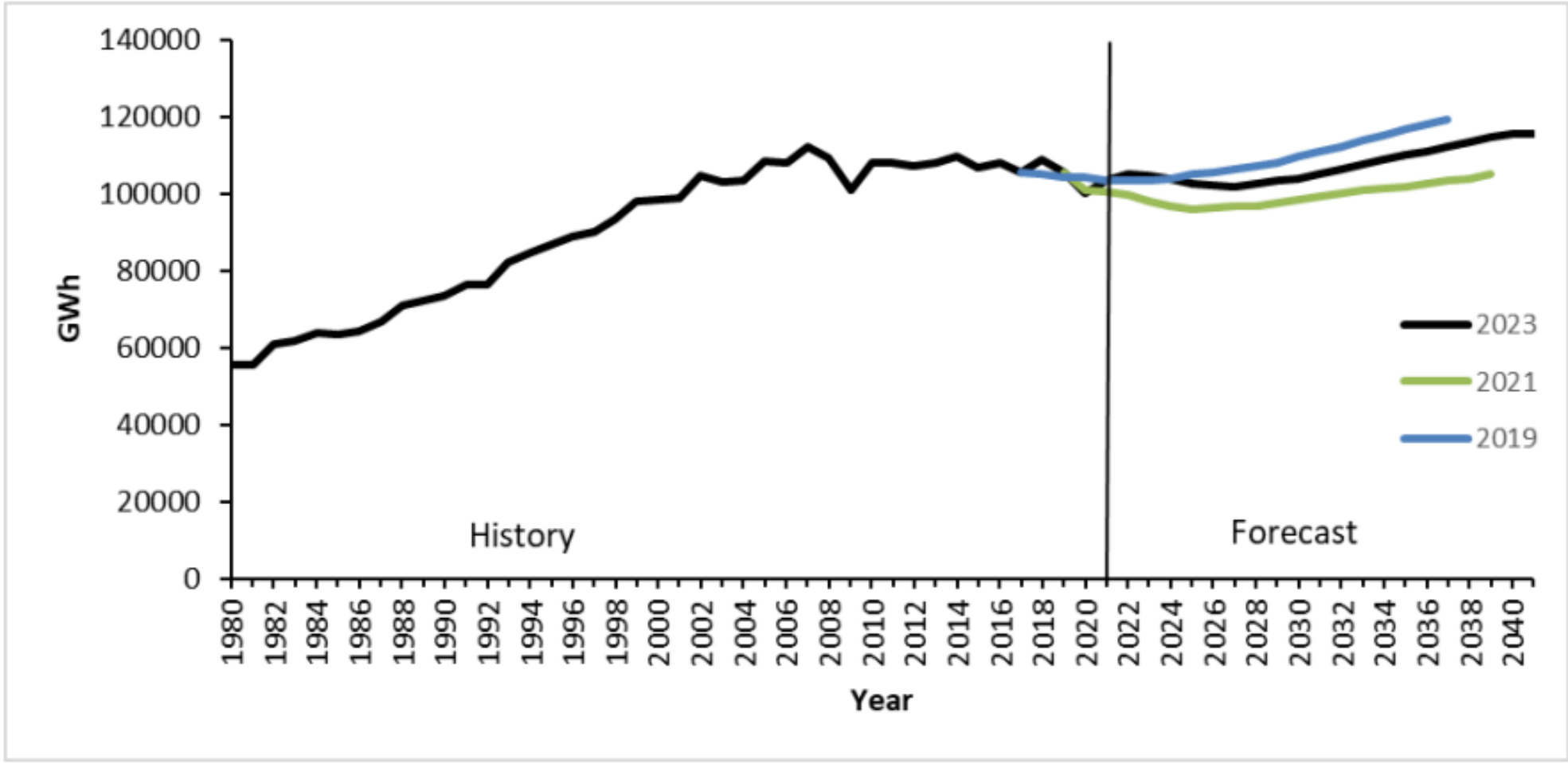
ENERGY PRICES & LOAD GROWTH

- The State Utility Forecasting Group, operated out of Purdue University, will have its new biennial state forecast out in early December.
  - 40 years of experience in forecasting electricity demand in Indiana.

PURDUE UNIVERSITY | State Utility Forecasting Group (SUFG)

Indiana Load Growth

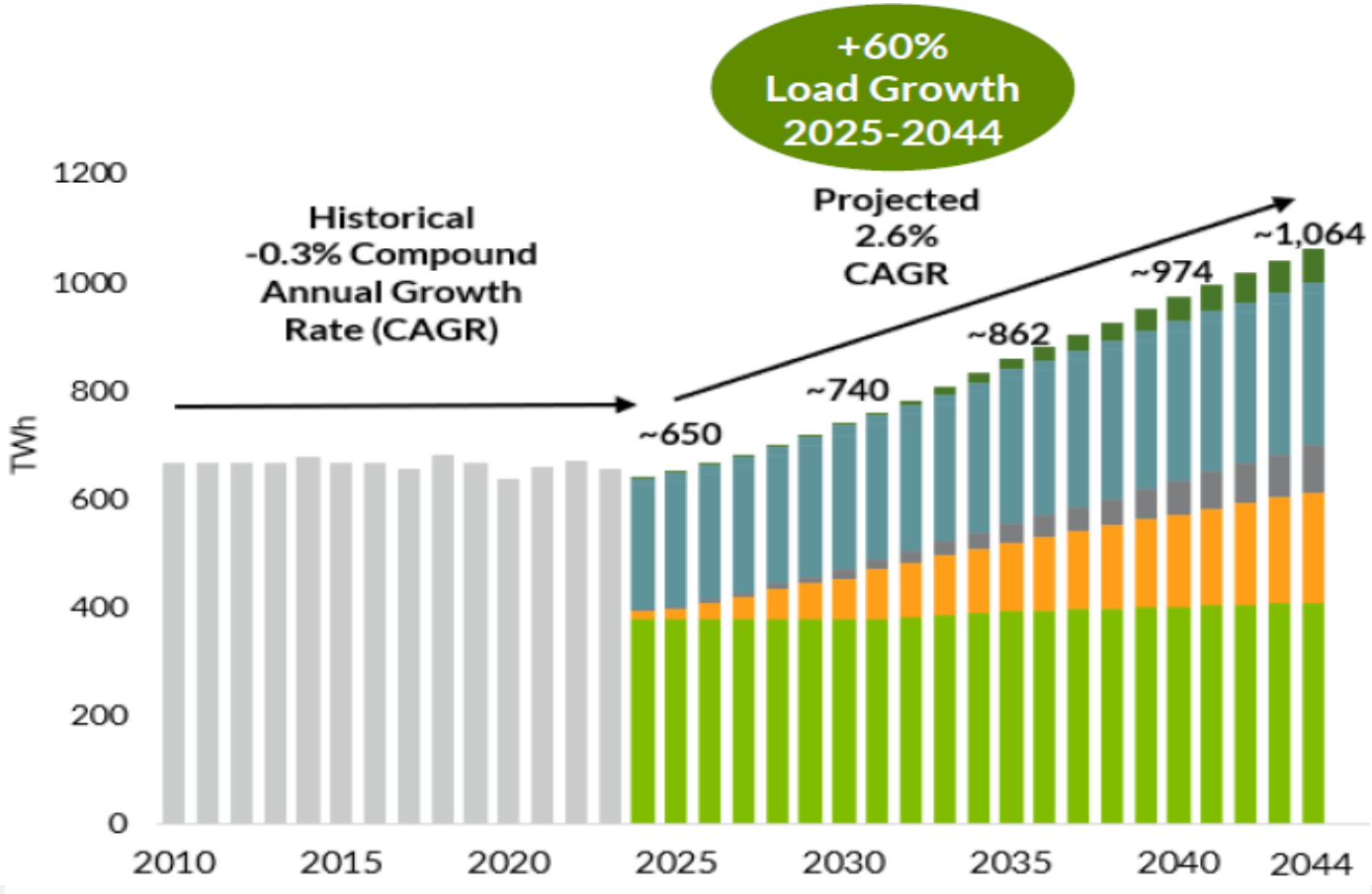
Figure 3-1. Indiana Electricity Requirements in GWh (Historical, Current, and Previous Forecasts)



Source: SUFG 2023 Report

Load Growth is Back!

- Both MISO & PJM are expecting large load growth rates



Source: MISO

Load Growth is Back!

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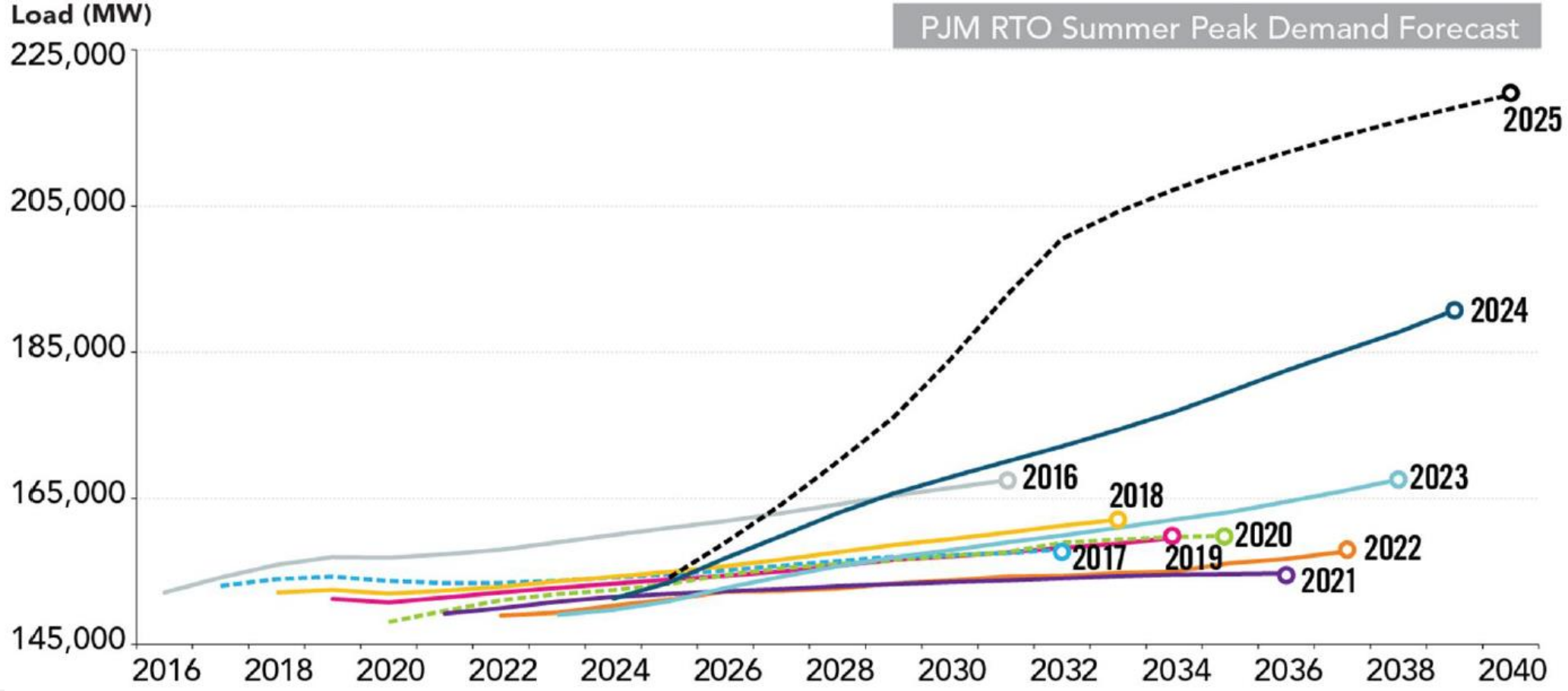


Source: PJM

What is Resource Adequacy?

- Simply put, resource adequacy is the ability of an electric utility to serve all of its customers during highest moment of demand (peak demand) in the year.
- Utilities plan to meet this peak demand plus a reserve margin to account for unplanned outages or other issues that may happen.
  - Remember, retail electric utilities have an obligation to provide safe and reliable service
- Participating in an RTO improves system reliability and economics.

Why Are We Hearing About This Now?

- Installed capacity ≠ production at time of system need.
- RTOs use accredited capacity to determine value of generation resources.
- Renewable generation accredited capacity is much lower than thermal generation.
- IRPs rely on current accreditation capacity policy from RTOs.

ACCREDITED OR EFFECTIVE CAPACITY

PY 2025-2026	Summer	Fall	Winter	Spring
Biomass	50%	46%	50%	49%
Coal	89%	84%	76%	73%
Dual Fuel Oil/Gas	87%	83%	79%	78%
Gas	88%	84%	65%	69%
Combined Cycle	95%	91%	77%	79%
Nuclear	94%	90%	90%	82%
Oil	77%	74%	74%	72%
Pumped Storage	98%	89%	76%	67%
Reservoir Hydro	89%	80%	76%	70%
Run-of-River Hydro	62%	52%	58%	63%
Solar	38%	21%	24%	32%
Wind	8%	15%	22%	14%
Storage*				
Status Quo**	39%	46%	66%	25%
Blended	50%	55%	70%	25%
Even Loss	62%	57%	71%	25%

- MISO DLOL Accreditation
- Notice that nuclear receives a much higher accreditation that both solar and wind resources in each season

ACCREDITED OR EFFECTIVE CAPACITY

	2027/2028 BRA ELCC Class Ratings
Onshore Wind	41%
Offshore Wind	67%
Fixed-Tilt Solar	7%
Tracking Solar	8%
Landfill Intermittent	48%
Hydro Intermittent	39%
4-hr Storage	58%
6-hr Storage	67%
8-hr Storage	70%
10-hr Storage	78%
Demand Resource	92%
Nuclear	95%
Coal	83%
Gas Combined Cycle	74%
Gas Combustion Turbine	61%
Gas Combustion Turbine Dual Fuel	77%
Diesel Utility	92%
Steam	72%
Waste to Energy Steam	83%
Oil-Fired Combustion Turbine	80%

- PJM ELCC Accreditation
- Notice again how nuclear performs very well.

RTO Warnings

- RTOs are concerned that projects are not moving to construction and completion.
- PJM has identified three main concerns:
  - Financing issues (related to costs and inflation)
  - Sluggish supply chain
  - Permitting issues (at the local, state, or federal level)
- In effect, each partner in the RTO is in some measure dependent on the other partners to accomplish the desired interconnected system reliability across the region.

WHAT ARE THE GRID OPERATORS SAYING?

1

PJM

- Retirements are at risk of outpacing new resources, due to a combination of industry forces including siting and supply chain issues; 95% of the PJM generation queue is renewables with completion rates of just 5%.

2

MISO

- Studies conducted by MISO indicate it is possible to reliably operate an electric system that has far fewer conventional power plants and far more zero-carbon resources than we have today. However, the transition that is underway to get to a decarbonized end state is posing material, adverse challenges to electric reliability.

3

NERC

- In 2023, for the first time, NERC considered “energy policy” among the five significant evolving and interdependent risks to grid reliability.

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

Data Center Landscape in Virginia

Presentation to NC Energy Policy Task Force

December 2, 2025

Summary

Overview of VA Regulatory Framework & Load Growth

Recent Actions Taken by SCC and General Assembly

Lessons Learned

Overview

- Dominion (2.7 million customers); APCo (500,000 customers); NOVEC (180,000 non-data center customers)

- Biennial base rate reviews; IRPs; annual RPS

- Virginia Clean Economy Act (2020)
  - Mandatory RPS – 100% by 2045 Dom/2050 (APCo)
  - Mandatory EE Program – 5% (2019 baseline) by 2028

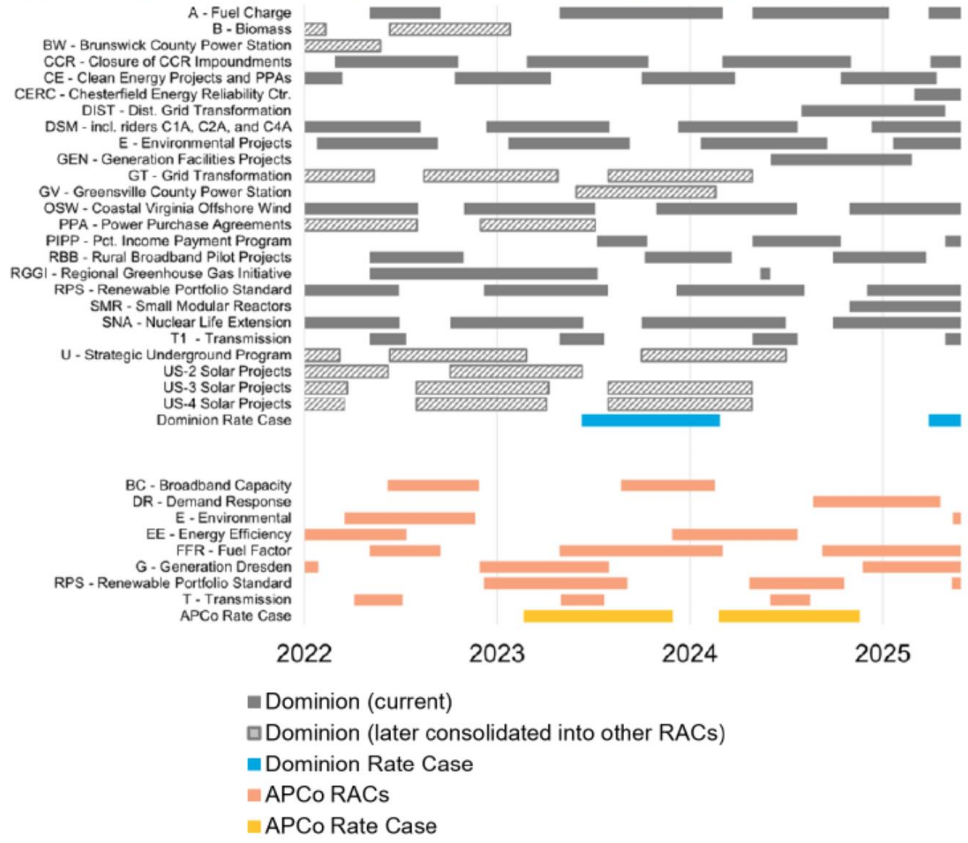
Overview

- "Virginia's regulatory framework is ***remarkably complex***…"

- "[R]eflect[s] an ***unusually high degree of ratemaking via legislation***" which "limits the ability of utilities and the SCC to adapt to developing circumstances in the energy system, as many ratemaking details are narrowly defined without room for holistic review of utility decision-making and prudence."

- *Opportunities for Performance-Based and Alternative Regulatory Tools in Virginia*, August 2025, PUR-2024-00152

Figure 1: Virginia RAC proceedings for APCo and Dominion, January 2022–May 2025

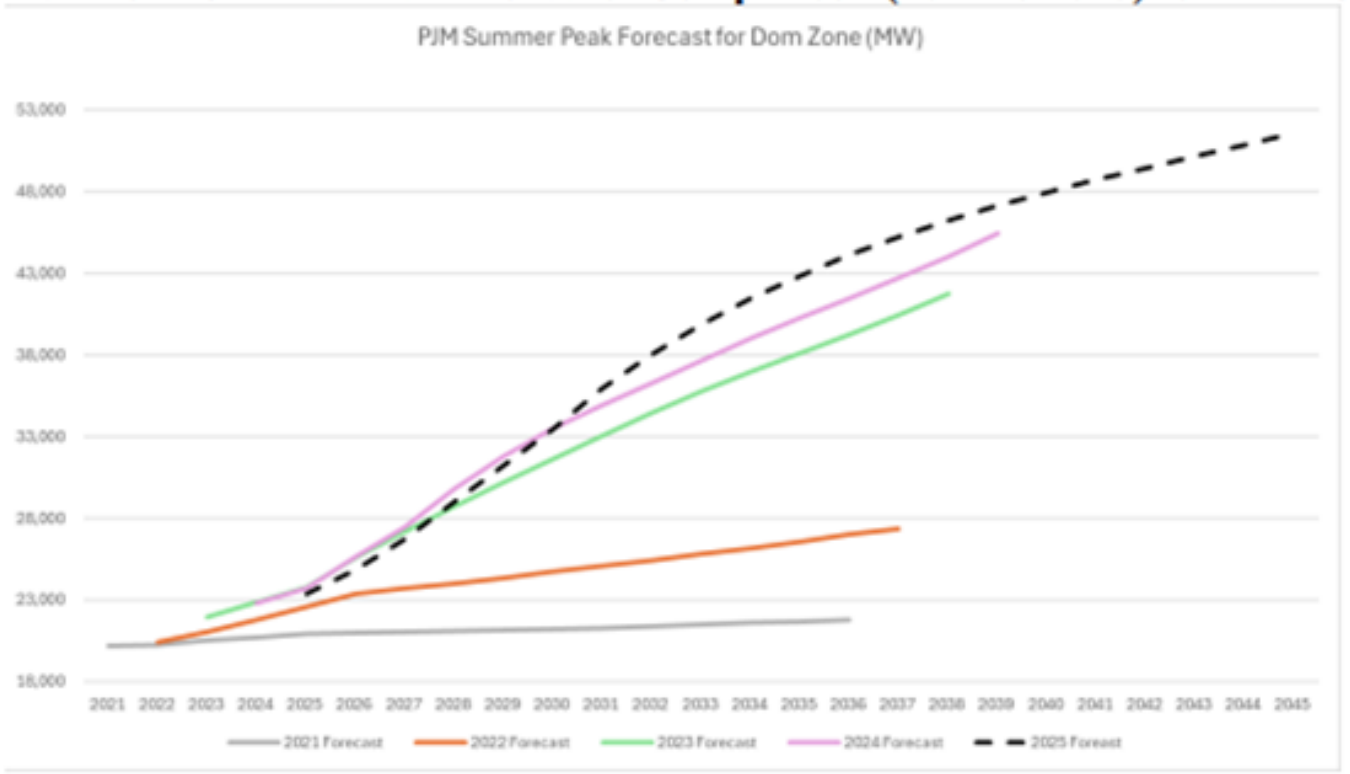


Sources: "Residential Rates," Dominion Energy, accessed July 24, 2025; "Business Rates," Dominion Energy, accessed July 24, 2025; Appalachian Power Company (APCo), *Virginia SCC Tariff No. 28*, December 11, 2024; Appalachian Power Company (APCo), *Select Schedule Charges and Associated Rider Charges*, January 1, 2025. Figure by CEG and GPI with assistance from PNNL.

Note: Timelines of proceedings for those RACs in effect on the Dominion tariff as of June 1, 2025 and APCo tariff effective January 1, 2025; see the Technical Report for additional discussion of this graphic.

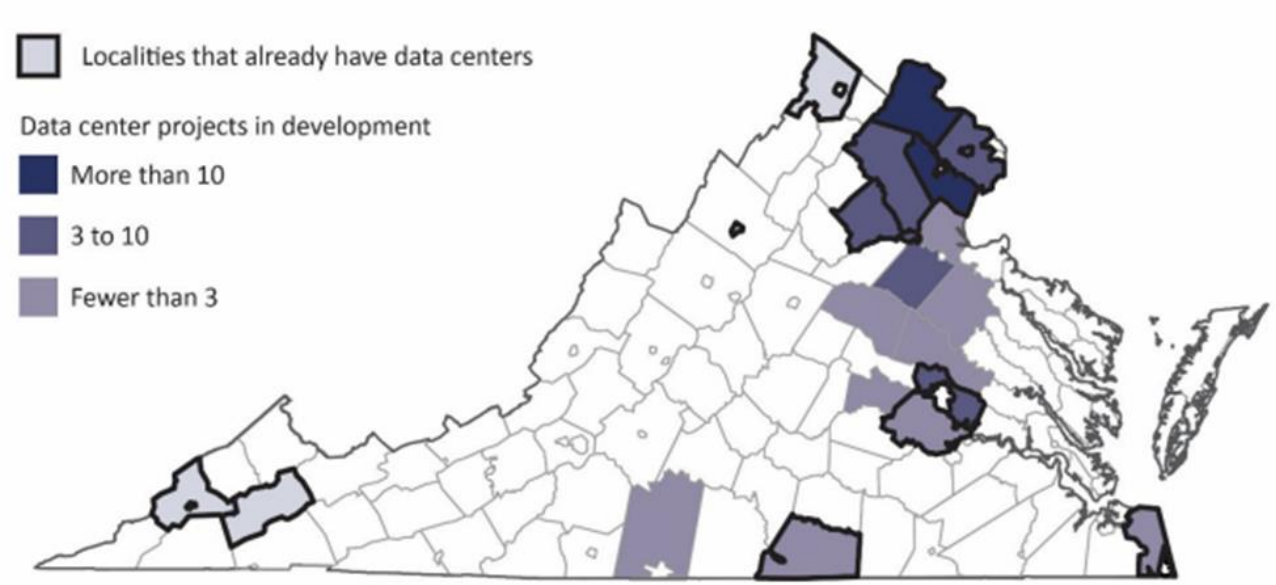
Load Grow in VA

Figure 2.1.3: PJM Summer Peak Forecast Comparison (2021 to 2025) for the DOM Zone



Load Grow in VA

FIGURE 1-4
Data center industry still growing in established markets, but development starting to spread into new areas, such as along I-95



SOURCE: JLARC summary analysis as of September 2024.
NOTE: "In development" includes projects that are under construction, permitted, and/or have been approved through local rezoning or other approval processes (if applicable).

Figure 7: Historical cost components of typical monthly residential electricity bill in Virginia (1,000 kWh consumption, summer month)

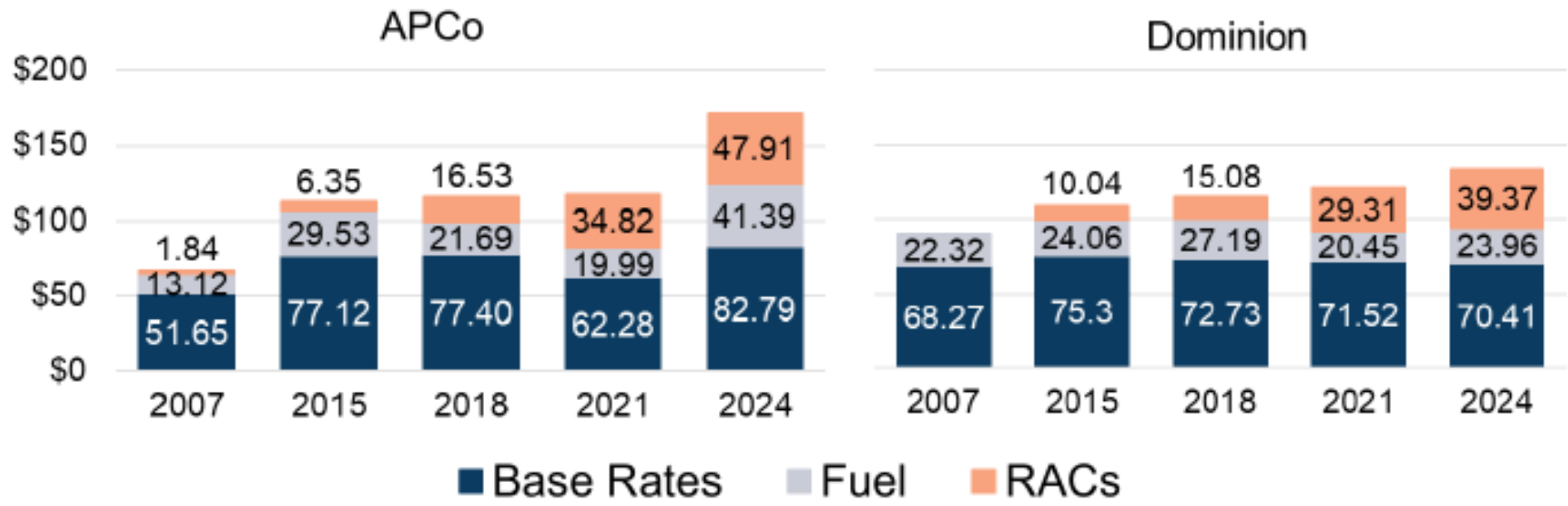
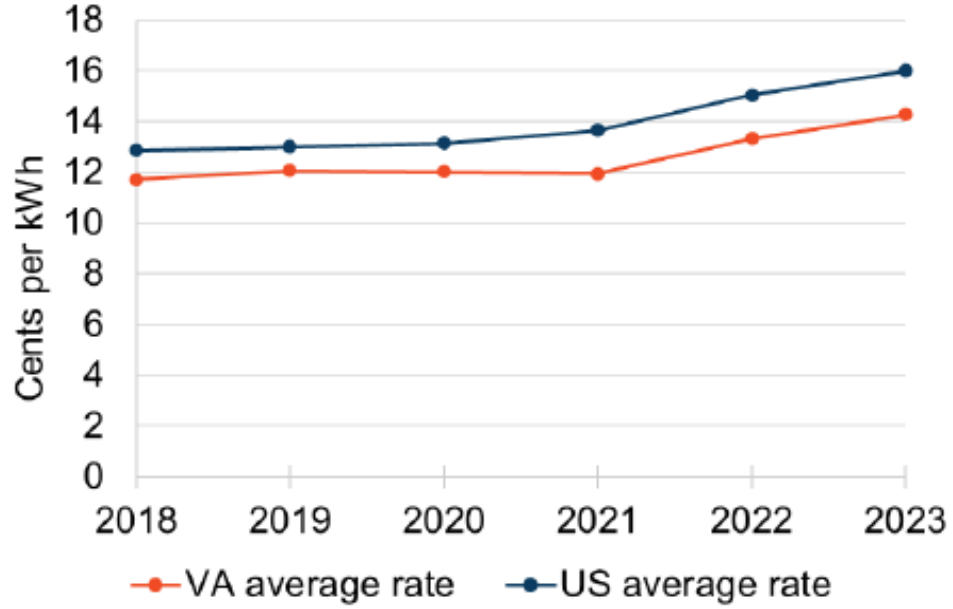


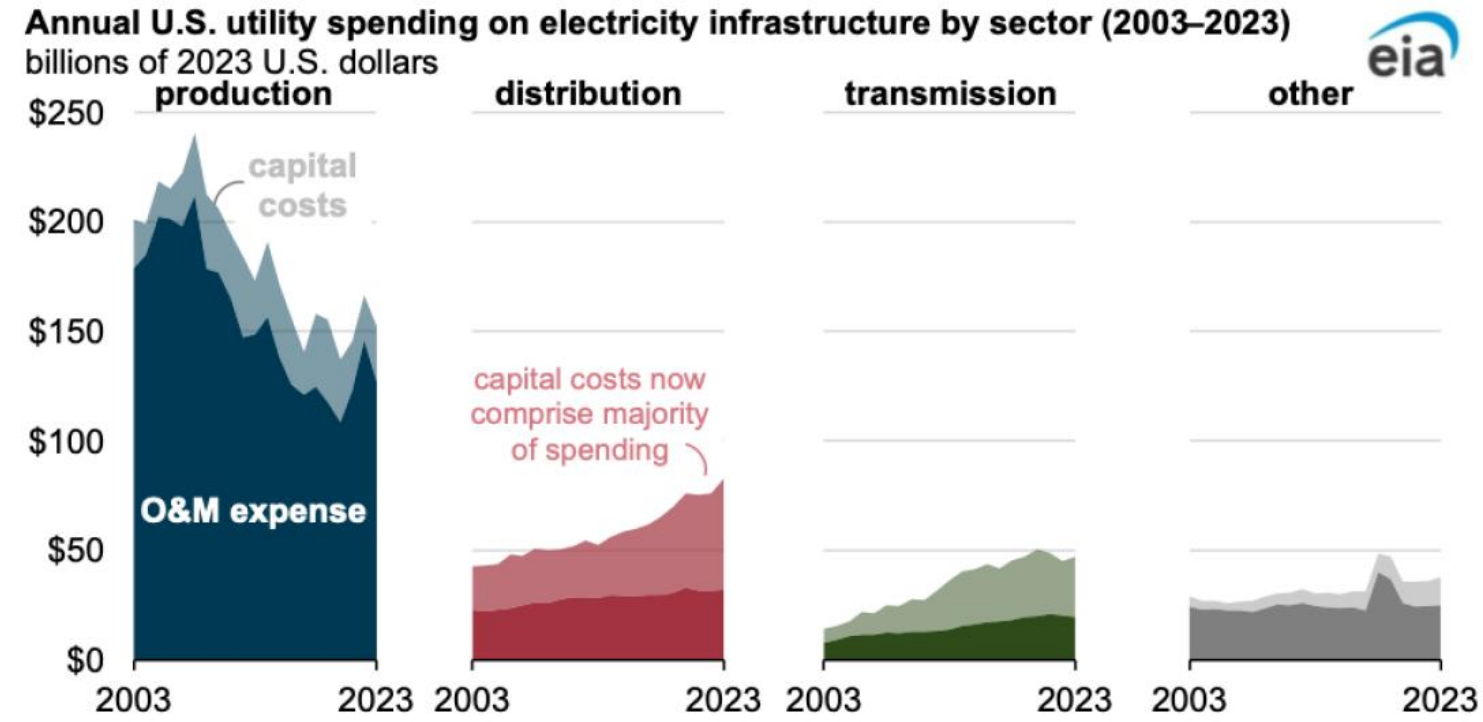
Figure 3: Average retail residential rate, Virginia and US (2018-2023)



Source: "Electric Sales, Revenue, and Average Price" (Table 4, January 2018–January 2023), US Energy Information Administration, accessed July 24, 2025. Figure by CEG and GPI with assistance from PNNL.

In 2023, Virginia's average residential electricity rate was 11 percent lower than the US average. From 2018 to 2023, residential electricity rates in Virginia increased by approximately 22 percent. Over the same period, average US residential rates increased by approximately 24 percent.

T&D capital investment represents the most significant source of long-term increased utility spending.



Data source: U.S. Energy Information Administration and Federal Energy Regulatory Commission (FERC) Financial Reports, as accessed by Ventyx Velocity Suite
Note: O&M=operation and maintenance

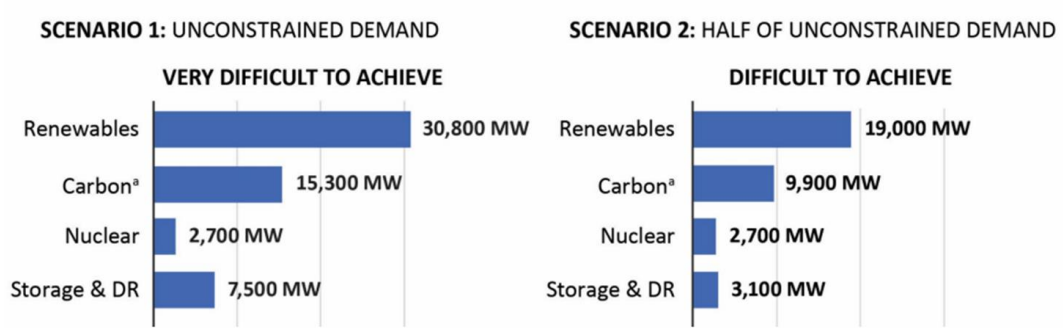
The Future…

Addressing energy demand would require substantially increasing current system capacity and energy imports

	Change from 2025 to 2040	
	Scenario 1: Unconstrained demand	Scenario 2: Half unconstrained demand
Generation (in-state)	+150%	+90%
Transmission (Interzonal)*	+40%	+35%
Imported energy (net)	+150%	+55%

Scenarios shown assume that Virginia Clean Economy Act (VCEA) renewable requirements are met.
*Transmission capacity is only interzonal lines to and from the Dominion transmission zone, where most data centers are located and most growth is expected to occur.

Breakdown of generation capacity that would need to be added (2025 to 2040)



Scenarios shown assume that Virginia Clean Economy Act (VCEA) renewable requirements are met.
[a] Carbon generation is from natural gas baseload and peaker plants. However, starting in 2045 (not shown), grid model assumes natural gas plants would be converted to hydrogen fuel.

Dom Virginia rate base is forecast to ***increase by approximately 68% from 2024-2029***. CapEx driven by transmission and distribution, as well as increased investments in renewable energy.

SCC Directed 2024 IRP Supplement Figure 3.1:
Sensitivity Modeling Results

	2024 IRP		No Data Center Load Growth		Updated Capacity Pricing			
Portfolio	REC RPS Only with EPA	VCEA with EPA	REC RPS Only with EPA	VCEA with EPA	REC RPS Only with EPA	REC RPS Only with EPA	VCEA with EPA	VCEA with EPA
Data Center Growth	With	With	Without	Without	With	Without	With	Without
Net Present Value (NPV) Total ($B)	$100.2	$102.9	$77.2	$80.8	$100.3	$77.3	$103.3	$80.9
Solar (MW)	11,932	12,210	11,560	12,210	11,932	11,560	12,210	12,210
Wind (MW)	3,460	3,460	60	60	3,460	60	3,460	60
Storage (MW)	4,577	4,100	-	2,250	4,577	-	4,100	2,250
Nuclear (MW)	1,340	1,340	-	-	1,340	-	1,340	-
Natural Gas Fired (MW)	5,934	5,934	3,398	2,580	5,934	3,398	5,934	2,580
Retirements (MW)	-	-	-	-	-	-	-	-

SCC Action to Address Affordability

- New GS-5 Rate Class (equitable cost allocation)
  - Evidence of Tx subsidy for data centers (ROR of 3% v. 22%)
  - > 25 MW
- Minimum demands & 14-year contract term (stranded asset risk)
  - Transmission/Distribution – 85%
  - Generation – 60%
- Directed Dominion to proposal alternative cost allocation methodology for base rates and Transmission Rider
- Large Load Interconnection Queue
  - Tech Conference on Flexibility Dec. 12, 2025

Legislative Action

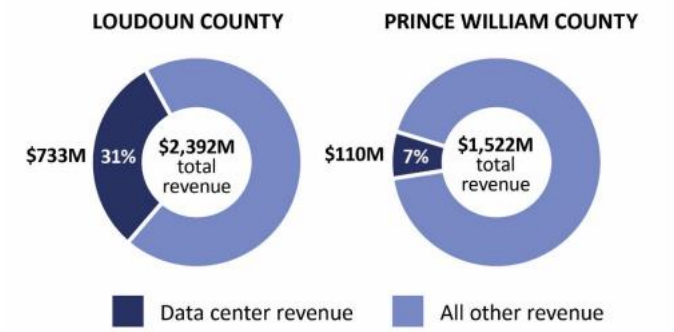
- 2025 – Directed SCC to use existing authority to consider whether a new rate class for large load was appropriate
- Upcoming 2026 Session – Commission on Electric Utility Regulation (CEUR)
  - Establish emergency load curtailment policy requiring large loads to enroll in mandatory demand response/curtailment program.
  - SCC-led workgroup on load flexibility
  - Examination of PBR opportunities (RAC consolidation; fuel factor cost-sharing)

Lessons Learned…

- Capital investment in VA data centers in substantial, but not all is in-state.

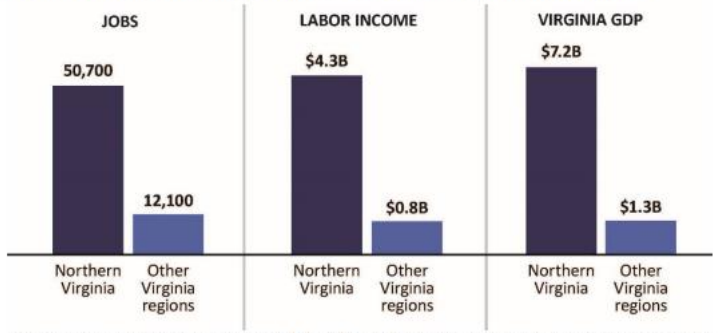
- Data centers generate substantial local tax revenues for localities that have them.
  - E.g., lower real estate taxes; develop an affordable housing trust fund; establish revenue stabilization or reserve funds; construct new schools.

FIGURE 2-4
Data center tax revenue can be substantial for local governments (FY23)



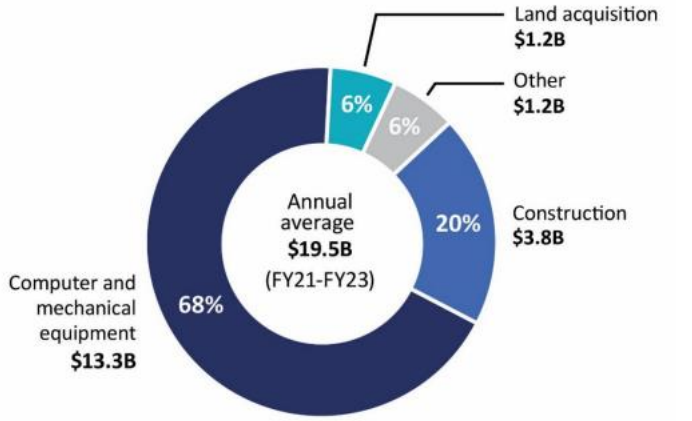
SOURCE: JLARC staff analysis of revenue collections from localities and the APA Local Government Comparative Report, FY23.

FIGURE 2-3
Economic impact from data centers is concentrated in Northern Virginia



SOURCE: Weldon Cooper Center economic analysis of the annual data center industry impacts, based on data center spending between FY21 and FY23 reported to VEDP, adjusted to account for non-exempt data centers.
NOTE: Totals for Northern Virginia and other Virginia regions do not sum to statewide totals shown in Table 2-1 because the analysis does not account for impacts from activity in Northern Virginia occurring in other Virginia regions and vice versa.

FIGURE 2-2
Primary benefit of data center capital investment to Virginia's economy is from construction, which comprises 20 percent of data centers' capital investment

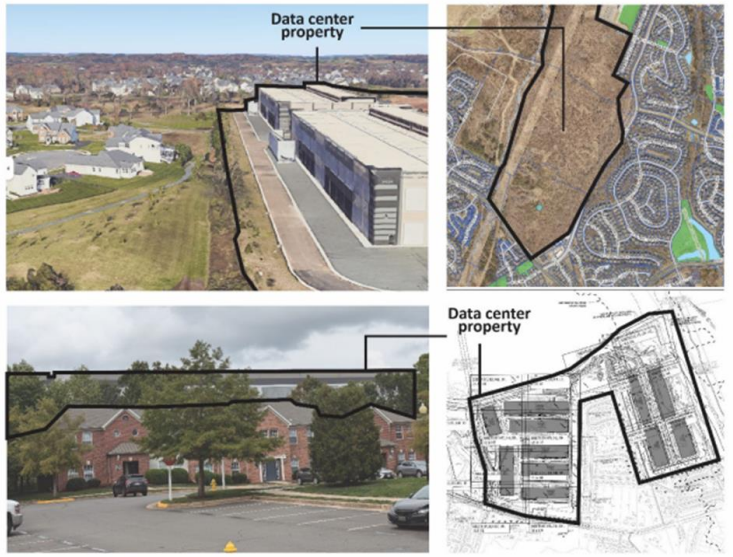


SOURCE: JLARC staff and Weldon Cooper Center analysis of data center capital investment between FY21 and FY23 reported to VEDP.

Lessons Learned…

- Different risk profiles for IOUs versus cooperatives/municipals
- Load forecasting – metered vs. contracted demand; slow ramp
- Different types of data centers have different reliability needs
  - *Also present unique opportunities*
- Challenges around limited retail choice for large loads in VA
- Data Centers have a growing PR problem

One-third of data centers are near residential areas, and industry trends make future impacts more likely



COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

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Task Force Subcommittee Updates

Technical Advisory Subcommittee

Josh Brooks, NC Sustainable Energy Association, Co-Chair

Technical Advisory Subcommittee, to focus on, as appropriate:

1. Advising the Office of the Governor on any commissioned modeling of North Carolina's electricity system.
2. Developing testable hypotheses and questions that can inform state energy policy.
3. Increasing transparency and public understanding of models used to inform energy policy, including their inputs and outputs, risks, and uncertainties.
4. Providing quantitative and qualitative assessment results and supporting information to other subcommittees.

Commissioned Modeling

The near-term modeling exercise aims to answer three key questions. These key questions are:

- Is there a reasonable resource scenario available to maintain system reliability and meet the state's policy goals?
- What are key assumptions that determine overall costs, future risks, and uncertainties for the NC electricity system?
- Are utilities appropriately forecasting future load, and if assumptions that forecast are changed, how would the required resource mix change?

The modeling exercise will have the following deliverables, informed by ongoing engagement with the Technical Advisory Subcommittee:

- **Base Case Modeling**: an electric systems scenario which will remain fixed
- **Scenario & Sensitivity Modeling**: 7-8 scenario or sensitivity runs, based on subcommittee surveys and discussions, to answer specific questions of interest
- **Final Report**: a public-facing report that consists of a high-level overview inclusive of key findings and a detailed modeling appendix

Scenario and Sensitivity Priorities

Scenarios

- Gas Price Forecast
- Path to Net Zero
- Alternative Large Load

Single-Variable Sensitivities

- No or Delayed Hydrogen Deployment
- Bad Creek II
- Thermal Fleet Pathways

Cost Assumption Sensitivities

- High Nuclear Capital Costs
- High Gas Capital Costs
- Policy Shift

Large Load Sensitivities

- Flexible Large Load
- Large Load Clean Energy Commitments

Load Growth Subcommittee

Senator Julie Mayfield, Co-Chair
Kathy Moyer, ElectriCities of NC, Co-Chair

Load Growth Subcommittee, to focus on, as appropriate:

1. Developing estimates of near term and longer-term load growth forecasts under varying economic outlook scenarios.
2. Assessing the implications of load growth and new large loads, including as related to existing resource capacity and reliability constraints, new resource needs, and transmission and distribution requirements.
3. Identifying technological and policy solutions, including load flexibility and demand response strategies, to address the growing energy needs of data centers and heavy industry.
4. Evaluating strategies for avoiding stranded assets while meeting growing electricity demand.
5. Identifying recommendations for minimizing residential rate increases and maintaining affordability while managing rising electricity demand.

Expert Presentations

- **Duke Energy**, **Dominion Energy**, the **NC Electric Cooperatives**, and **Electricities of NC** presented on load forecasting methodologies, how to plan for and predict large load additions, and other drivers of load growth;
- the **NC Economic Development Partnership** presented on the energy needs of incoming businesses and their economic data for large load customers
- the **Duke University ALIGN Initiative** presented on the recent FERC proposed rulemaking for speeding interconnection of data centers
- **Google** and **Amazon Web Services** presented on the energy needs of data centers and how they work with utilities and local governments to source energy and address sustainability concerns

Policy Research

Policy Categories

- cost allocation and reduction (e.g., large load tariffs)
- on-site energy (e.g., co-location)
- grid capacity (e.g., reconductoring, aggregation)
- planning and data access (e.g., tracking interconnection requests)

Policy Goals

- affordability
- reliability
- sustainability
- economic development
- emissions reductions
- opportunities for innovation

- These are not exhaustive lists - as the subcommittee further discusses these options, new priorities and categories may emerge

Report Outline

The Subcommittee convened a Report Writing Working Group to develop a draft outline for the report:

- Executive Summary
- Landscape
- Task Force Activities
- Implications & Policy Approaches
- Key Findings
- Recommendations
- Conclusion & Future Directions

Discussion & Next Steps

Discussion

- The Load Growth Subcommittee has researched and refined a range of possible policy approaches:
  - Some key approaches, per subcommittee direction, are large load tariffs, green tariffs, on-site energy, load flexibility, and energy efficiency
- In small groups, discuss the following questions:
  - What approaches to load growth should be prioritized?
  - How could these be implemented by different authorities in NC?

Future Meetings

- **Full Energy Policy Task Force**
  - Next meeting scheduled for January 22, 2026
- **Load Growth Subcommittee**
  - Next meeting December 11th 3:00 – 4:30 pm
  - Meeting biweekly on Thursdays from 3:00 – 4:30 pm
- **Technical Advisory Subcommittee**
  - Next meeting December 15th 1:30 – 3:30 pm

Adjournment

Secretary Wilson