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Options on a Continuum of Competition for the Southeastern Electricity Sector

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Key Questions

- If stakeholders want to explore competition in the Southeast electricity sector as a way to achieve various policy goals, what options are available?
- Where do these options exist today?
- What questions might stakeholders want to ask, to get a better sense of the potential benefits, costs, and risks or challenges of these options?

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Executive Summary

Conversations around the future of the southeastern electricity sector are lighting up across the region, from stakeholder discussions on the North Carolina Energy Regulatory Process to RTO study bills and utility negotiations around a Southeast Energy Exchange Market. Stakeholders may come to the table with different perspectives and positions, but they share the common goals of reliability, affordability, and adaptability given new technologies, external threats, and shifting customer demands. Competition comes up a great deal in these conversations; too often the concept sends stakeholders into two distinct camps. And yet, competition is not a yes or no question. Therefore, the purpose of this policy brief is to describe different ways to engender consumer choice, third-party participation, resource sharing, and regional grid management in the power sector, using existing examples from this region. It includes questions stakeholders might think through in these conversations, and fundamentally aims to educate and inform.

SUMMARY OF the CONTINUUM OF COMPETITION

A
- Offer consumer choice, third-party participation options.
- Requires changes to cost-of-service model but leaves the general architecture intact.

B
- Require VIUs to purchase generation from other entities.
- Alternatively, require VIUs to demonstrate self-generation is lowest cost.

C
- Share resources through existing power pools across VIUs, rural coops, and municipal utilities in the region.
- Can leverage regional resources to meet demand.

D
- Operate an Energy Imbalance Market (EIM) through a nearby power market for voluntary participation by southeastern utilities.
- Participating utilities can offer reserve transmission capacity for use by the grid operator.

E
- Encourage or direct VIUs to form or join an RTO/ISO.
- Grid operator controls transmission and dispatches utility, merchant resources based on cost.

F
- Restructure utilities.
- Most restructured states sit in the footprint of an organized market, but a utility need not be restructured to join a market.

BACKGROUND

The American power sector began with small-scale, distributed systems. Then, in the early twentieth century, utilities began building capital-intensive networks to electrify the United States. Regulators viewed these utilities as natural monopolies that could leverage economies of scale to deliver this infrastructure at lowest cost. This thinking gave rise to cost-of-service regulation of monopoly vertically integrated utilities (VIUs) by state utilities commissions. This construct hummed along in most regions of the country so long as demand grew and electricity was a fungible commodity. But as the demand curve began to flatten in the 1970s and energy security concerns rose, the VIU and its expansion model faced new challenges.

Policy makers looked to third parties to respond more nimbly to market needs, including reduced energy demand and the development of alternative energy sources.[1] Responding to efficiency and competitiveness concerns, Congress empowered the Federal Energy Regulatory Commission (FERC) to require "open access" on utility-owned transmission lines to other buyers and sellers.[2] This opening up of the wires on a case-by-case basis set the stage for more coordination of balancing authorities and the transfer of some transmission management to third party Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). FERC encouraged but did not require the creation of these organizations at the turn of this century.[3] In combination with state restructuring laws, FERC's actions helped drive a rapid growth of Independent Power Producers (see Fig. 1). Yet in most states, the power sector is still dominated by VIUs.[4]

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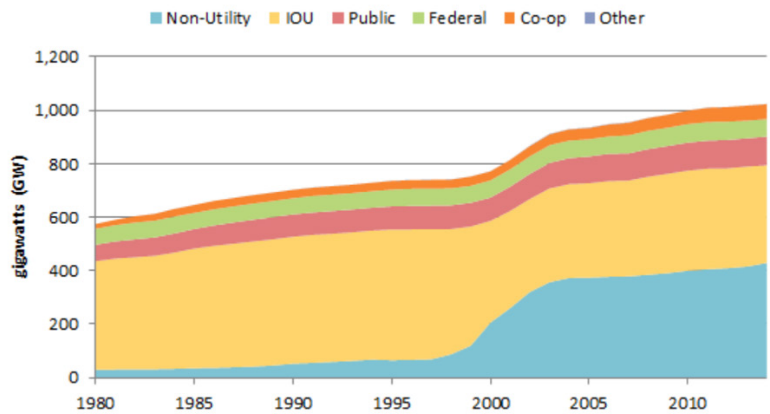
1. *See, e.g.,* the Public Utilities Regulatory Policies Act, Pub. L. 95-617, 92 Stat. 3117, 16 U.S.C. Chapter 46 (1978).
2. Energy Policy Act of 1992, Pub. L. 102-486, Sec. 721; 106 Stat. 2915 (Oct. 24, 1992).
3. FERC Order 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 75 FERC ¶ 61,080 (Apr. 24, 1996) (proposing to use of Independent System Operators to facilitate open access); FERC Order 2000, Regional Transmission Organizations, 89 FERC ¶ 61,285 (Dec. 20. 1999).
4. *See, e.g.,* Ari Peskoe, Unjust, Unreasonable, and Unduly Discriminatory: Electric Utility Rates and the Campaign Against Rooftop Solar, Texas

Figure 1. U.S. Generation Fleet by Ownership Type, 1980–2014[5]



In the twenty-first century, the electricity sector has faced a new wave of challenges—an aging coal and nuclear fleet, falling natural gas and renewables costs, and customer and public policy preferences for cleaner generation. As the coal-to-gas shift began, smaller merchant generators in fully competitive markets were the first to feel the pinch; in the past decade, regulated utilities have appeared better able to weather rapidly changing market conditions.[6] Yet VIUs are not immune from market forces. These utilities feel pressure to provide access to lower-emitting and/or more distributed generation, amid flattening demand and opposition to increases in electricity rates. This pressure is exerted on all sides, from big box retail stores and auto assembly plants wanting to procure 100 percent clean energy, to a coalition of Sierra Club and Tea Party members urging third-party participation in Georgia's rooftop solar market.[7]

Moreover, regulators in cost-of-service states must approve cost recovery and rates of return for capital expenditures. While this scheme can insulate a utility from construction overruns or unforeseen changes in market demand, at some point regulators do not view these costs as reasonable and prudent.[8] For instance, in 2017 the Georgia Public Service Commission reduced Georgia Power's return on equity for its Vogtle nuclear project following a series of construction delays.[9] In South Carolina, the legislature has been debating the future of the state-owned utility and to what extent customers should pay the sunk costs for a cancelled nuclear project.[10]

Out of this dynamic set of circumstances, southeastern states and stakeholders are exploring the role competition plays and might play in the power sector. These discussions are animated, reflecting high stakes for incumbent utilities, regulators, and electricity customers. Sometimes, they have resulted in concrete policy proposals, including a proposed retail choice ballot initiative in Florida,[11] RTO study bills in the Carolinas,[12] and an Arkansas Public Service Commission investigation into third-party bidding of distributed energy

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Journal of Oil, Gas, and Energy Law Vol. 11:2 (2016).
5. ABB Velocity Suite 2015 (reprinted in Jeffrey Logan et al., Electricity Generation Baseline Report, National Renewable Energy Laboratory, NREL/TP-6A20-67645 (Jan. 2017).
6. *See, e.g.,* Power Commentary, Searching for Relief from the Headaches Facing the Merchant Power Sector (Sept. 6, 2018).
7. Carolyn Kormann, Greening the Tea Party, The New Yorker (Feb. 17, 2015).
8. See, e.g., North Carolina G.S. § 110.1(f1); 110.6(e) (even costs associated with cancelled out-of-state generation to meet in-state load can be recovered by NC ratepayers so long as reasonable and prudent).
9. Georgia Public Service Commission News Release, Commission Approves Continued Construction of Nuclear Power Plant Vogtle Project; Reduces Company Revenue Requirement by $1.7 Billion (Dec. 21, 2017).
10. Avery G. Wilks and Andrew Brown, Santee Cooper Plans $520 Million Settlement of Customer Lawsuit over Failed SC Nuclear Project, The Post and Courier (Feb. 21, 2020).
11. Claudia Adrien, Florida Supreme Court Halts "Energy Choice" Ballot Initiative, Daily Energy Insider (Jan. 10, 2020) (reporting that the court struck the ballot initiative for having misleading language).
12. South Carolina bill S. 998 (2019-2020); North Carolina H.B. 958 (2019).

resources into bulk power markets.[13] In a subset of instances, southeastern policy makers have in fact expanded competition, for instance through competitive procurement of renewables[14] and the carving out of electric vehicle charging from services that can only be provided by a "public utility."[15]

Competition is not a binary choice. Introducing competition to various degrees—for instance by enabling third party participation in wholesale or retail markets or requiring a utility to consider wholesale procurement of power as a "least cost" way to meet some of its load—may incent utilities to be more efficient and responsive to market demand. States can also choose to enable competition in select submarkets, to provide goods and services that a utility is not well positioned to provide, or where costs may not be fairly allocated across all customer classes.

Many permutations of wholesale and retail competition in the electricity sector exist today in different parts of the United States, including in the Southeast.

This paper lays out options along a "continuum of competition," offering information to states, utilities, and stakeholders to reference in conversations about the region's power sector. We describe each option, offering real-world examples of each permutation. We examine how each option might realistically play out based on available research and suggest questions that stakeholders might consider when exploring these options. We also identify steps that would be needed to effectuate one or more policies in a typical southeastern state.

OPTION A: OFFER CONSUMER CHOICE, THIRD-PARTY PARTICIPATION WITHIN THE COST-OF-SERVICE MODEL

There are a number of ways to modestly expand competition within a traditional cost-of-service model. Option A focuses on actions that give electricity consumers more choice, or expand services by enabling third-party participation. Some of these actions make changes to the cost-of-service model but leave it largely intact.

A long-standing but often overlooked example of a customer choice policy is one that enables residents of a municipality to create their own utility,[16] and then "municipalize" existing power infrastructure.[17] In this context, "customer choice" means a group of consumers determining at a single point in time whether to create a public power entity instead of receiving electric utility service from the investor-owned utility. This does not empower those consumers to jump from provider to provider to take advantage of cost savings or particular types of service.

Beyond this example, models for enabling customer choice in cost-of-service states have focused on large commercial and industrial customers. These include allowing large customers to choose their utility; work with the utility to procure bespoke renewable power; or exit the utility customer base entirely and self-supply. As noted in the questions section below, expansion of these programs should consider the risk of enabling large customers to procure their own power or exit the service territory, leaving much of the utility's fixed costs to be spread across other customers. (In some cases, industrial customers self-procuring power would still pay stand-by and wheeling charges, reducing the magnitude of the fixed costs to be re-allocated.)

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13. *See* Arkansas Pub. Serv. Comm., In the Matter of an Investigation of Policies Related to Distributed Energy Resources, Order (July 27, 2018). In 2019 and 2020, the Commission has hosted five Educational Workshops on the issues in this docket; as of July 22, 2020, no substantive decision had been made. See Docket No. 16-028-U.

14. North Carolina H.B. 589 (2017).

15. *See, e.g.,* Florida Statutes 366.94 (2019) (EV charging made available to be public by a nonutility is not a retail sale of electricity); North Carolina G.S. § 62-3(23)(n) (excluding certain sellers of electricity at EV charging stations from the definition of "public utility").

16. *See, e.g.*, South Carolina Constitution, Art. VIII, Sec. 16; Tenn. Municipal Electric Plant Law of 1935, § 7-52-103. Similarly, businesses or individuals can create a nonprofit power cooperative and receive federal loans for power infrastructure. *See* Rural Electrification Act of 1936, Pub. L. 74-605, 49 Sta. 1363.

17. *See, e.g.*, Georgia Stat. § 46-3-8(h).

Alternatively, third parties might be authorized to provide tailored products and services to all customers, including residential customers. Again, thought should be given to the allocation of costs and benefits across all electricity consumers. However, where third-party participation can relieve a fixed cost burden on the utility while democratizing access to new products, third-party participation could provide a beneficial complement to traditional utility services. Certain types of products and services may lend themselves more naturally to third party participation in a system that maintains traditional monopoly service:

(1) **Technologies or services that are misaligned with VIU profit incentives.** By definition, a large, successful VIU is not well equipped to identify, let alone embrace, products and services that could undermine its business model.[18] For instance, in a cost-of-service model based on volumetric sales, a utility may be resistant to offer energy efficiency and demand response services that reduce customer load.[19] Therefore, some Southern states have sought to incentivize these resources and programs by ensuring compensation.[20] Even so, if a utility earns revenues based on the volume of electricity purchased, plus a rate of return on capital investments, there may be a structural disincentive to invest in demand-side projects.[21] So long as this disincentive persists, third-party participation in demand management might be worth exploring, particularly as a tool to slow customer rate increases. Similarly, nontransmission alternatives to delay construction of new transmission lines may not be apparent or attractive to a company looking for capital investments. Recognizing this, Dominion spun off Dominion Voltage Inc. to focus on grid efficiency.[22]

(2) **Investments Carrying Regulatory Risk.** In recent years, some utilities commissions have rejected or scaled back utility proposals to install electric vehicle charging infrastructure, because of the uncertainty of demand and the possibility of non-EV owners subsidizing EV owners (this also relates to the next category).[23] Third parties can fill this niche and demonstrate a market need for emerging technology, which might bolster the utility's ability to file a more successful infrastructure proposal down the road.[24] In the process, they'll support price discovery, helping the regulators understand the "going rate" for emerging technology from battery storage to fuel cells so that if and when the utility proposes investment in these technologies, the utility and the state have a frame of reference for reasonable cost.

(3) **Niche markets.** Utilities commissions might also reject proposals for products and services out of concern that the utility would only be serving a small subset of customers, or one class of customers. State laws in the region generally discourage discrimination between utility customers.[25] Georgia

18. Clayton M. Christensen, The Innovator's Dilemma: When New Technologies Cause Great Firms to Fail, 1997 (Harvard Business Review Press: Cambridge, Massachusetts).

19. Decoupling and performance-based mechanisms could also potentially align a utility's business model with embracing energy efficiency and demand response within a monopoly construct.

20. *See, e.g.,* Georgia Stat. § 46-3A-9 (allowing a utility cost recovery for demand-side capacity options "to encourage the development of such resources"); North Carolina G.S. §62-2(3a) (asserting it is state policy to consider "appropriate rewards to utilities for efficiency and conservation which decrease utility bills").

21. Rate of return regulation prohibits utilities from earning a profit on their operating costs, preventing mark-ups of fuel and other inputs. It also creates an incentive to build and acquire new capital assets, which encourages system modernization but can discourage repairs and operational solutions even when they are more economical.

22. Dominion Voltage Inc. website (last visited July 21, 2020); see also Dominion Voltage Inc. News Releases, DVI's Edge Solution to Improve Energy Efficiency, Lower Customer Bills for Canada's Lethbridge Electric Utility (Mar. 7, 2018).

23. *See, e.g.,* Maryland Pub. Serv. Comm. Order No. 88997, In the Matter of the Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio (Jan. 14, 2019) (scaling back a proposed program approximately 80%); Kansas City Power & Light Company's Application for Approval of its Clean Charge Network, Docket No. 16-KCPE-160-MIS, Kansas State Corp. Comm. Order (Sept. 13, 2016) (denying application); Robert Walton, Duke Defends North Carolina EV Pilot Program After Regulatory Staff Recommends Rejection, Utility Dive (July 15, 2019); but see Application of Louisville Gas & Electric Company & Kentucky Utilities Company, Case No. 2015-00355, Kentucky Pub. Serv. Comm. Order (April 11, 2016) (approving application).

24. Utilities may have concerns that first movers could site charging infrastructure in the areas likely to see the highest rates of demand, thereby "cherry-picking" the most cost-effective spots.

25. *See, e.g.,* Georgia Stat. § 46-3-11(a); Kentucky Revised Statutes 278.285(3); North Carolina G.S. § 62-140.

statute also prohibits, for example, offering a consumer "lesser charges or more favorable terms or conditions for retail electric service" for agreeing to accept good or services "not reasonably related to the furnishing of retail electric service."[26] With such prohibitions in place, a utility might be constrained from offering products and services likely to benefit only a subset of customers, or one customer class. Similarly, discrimination laws may inhibit the use of discounts or other customer inducements to encourage uptake of a new product or service and broaden its appeal. Third parties, by contrast, can serve a niche market in perpetuity, or attract a broader customer base to a product or service through targeted discounts and promotions.

(4) High transaction costs. As noted above, VIUs were initially attractive because of the economy of scale they could achieve. By contrast, VIUs are less adept at deploying or leveraging small-scale products, particularly those needing to be tailored for nonfungible residential customers. The cumulative transaction costs are likely to be prohibitive for a large company with a lot of overhead, if these costs cannot be rate-based. The incremental profit on each transaction may not excite corporate interest; the cost-benefit analysis may concern regulators. Small or niche third-party ventures may more nimbly meet the need, if they have lower overhead costs. Third parties might also be better able to invest in creative outreach strategies. For instance, a nonutility could encourage many people in the same neighborhood to install rooftop solar all at once, thereby bringing down the costs for each homeowner (the Solarize model),[27] or provide rebates for home thermostats in exchange for control over that thermostat to reduce peak load.[28] In some cases, these third parties can then aggregate small projects to participate in a utility's demand response program or to bid into neighboring competitive markets. Access to utility customer data and mapping of distribution capacity for optimal renewables siting may be necessary to unleash the potential of third-party participation in this category.

(5) Public policy goals. Enabling and encouraging third-party participation in the achievement of public policy goals can help to reach these goals in the most cost-effective way, particularly where public policy goals extend beyond the core business mission of the investor-owned utility.

Design Alternatives/Living Examples

There are a number of examples of consumer choice and third-party participation in the southeastern power sector.[29]

Consumer Choice

Traditionally, public power has been the definition of customer choice in the Southeast. Some of the **municipal utilities** predate the large regional VIUs, and every southeastern state presently authorizes municipalities to form their own utility.[30] Then, beginning in the 1930s, the United States began offering loans to self-organized rural communities to produce or distribute electric power where VIUs did not find it profitable to go, giving rise

26. Georgia Stat. § 46-3-11(b)(2).
27. *See, e.g.* Solar Crowd Source, "Solarized Campaigns" website (last visited July 22, 2020).
28. Nest thermostat invited customers to opt-into a load reduction program for the August 2017 solar eclipse, when grid operators raised the alarm that solar power would be strongly affected. More than 700 MW in load was reduced through the Nest program during the eclipse. *See* Brenda Chew, "The Grid's Shape-Shifter: Why Demand Response is Becoming an Indispensable Part of Grid Modernization," Smart Electric Power Alliance (Oct. 18, 2018).
29. For a more detailed list of this type of competition, see Jonas J. Monast, Franz T. Litz, Kate Konschnik, Harnessing Competition in a Changing Electricity System: Opportunities for Traditional Cost-of-Service States.
30. *See, e.g.,* N.C. G.S. § 106A-312 (authority to operate a "public enterprise," defined at 106A-311 to include "electric power generation, transmission, and distribution systems"), S.C. Constitution, Art. VIII, Sec. 16 (authorizing incorporated municipalities by a majority vote of the electors acquire or construct public utilities including electric utilities); Tennessee Municipal Electric Plant Law of 1935, Tenn. Code 7-52-103 (authorizing municipalities to run electric power plants and to provide service to "any person, firm, public or private corporation, or to any other user or consumer of electric power and energy, and charge for the electric service").

to **rural electric cooperatives**. Today, in six Southern states, more than 10 percent of electricity customers are served by municipal utilities or rural electric cooperatives (also known as electric membership corporations).[31]

In some instances, **large consumers** are allowed to select a utility or opt out of utility services. In many southeastern states, the legislature has assigned utilities to specified service territories[32] or empowered the utility commission to assign or approve utility territorial agreements;[33] in either case, these assignments grant monopoly electric service. However, in Georgia, if a new customer builds a new facility with a load of 900 kilowatts or greater, that "large load" consumer can select their preferred electricity service provider, as between nearby suppliers.[34] In a dispute over this provision, the Georgia PSC observed that "[b]y encouraging healthy competition between electric suppliers for large load customers, electric suppliers will strive to provide reliable electric service at the least cost to the consumer … ."[35] (This example is a modest version of retail choice that, aside from Texas, does not currently exist in the South.)

Narrower industry choice exists in North Carolina, where **industrial customers can opt out of a utility's demand side management and energy efficiency programs**.[36] This enables customers to determine whether they or the utility can implement more cost-effective energy savings measures, and on what timetable given other investment needs.

For nearly 20 years, Nevada has empowered large governmental entities, or commercial or industrial customers with an average annual load of at least one megawatt, to **exit a monopoly utility's territory** and self-procure energy, capacity, and ancillary services.[37] The state utility commission must approve the decision, subject to a finding that the transaction is in the public interest and will not increase costs to the utility's remaining customers. Rapidly falling renewables costs have triggered a small wave of recent exits; even when the Nevada PUC denied an application the customer appears to have used the docket as leverage with the utility, resulting in the utility's procurement of additional renewables for the customer.[38] Virginia has a similar law, limited to consumers with a peak demand over five megawatts (with or without aggregation; aggregation requires Commission approval).[39]

Short of outright exiting, some southeastern states authorize large industrial and commercial customers to source clean energy through tailored agreements with the regulated utilities.[40] These **green tariff programs** or "sleeved power purchase agreements"[41] require the customer to pay a premium to the utility for this power, to

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31. American Public Power Association, 2019 Statistical Report (reporting that in 2017, 20.2% of Alabama customers, 12.2% of Arkansas customers, 13.4% of Florida customers, 10.4% of North Carolina customers, 13.0% of South Carolina customers, and 68.5% of Tennessee customers get their electricity from public power).

32. For instance, the Georgia Territorial Electric Service Act assigns every geographic area in the state to an electric service provider or designates areas as "unassigned." Georgia Stat. § 46-3-1. Geographic areas were assigned in 1973 based largely on "the location of electric suppliers' lines;" only one electric supplier would then operate within that area. Georgia Stat. § 46-3-4(2).

33. *See, e.g.,* Florida Stat. 366.04(2)(d); see also Florida Utilities Code, 25-6.0440.

34. Georgia Stat. § 46-3-8(a). The choices are limited to the existing "primary supplier" or "secondary supplier" if the new premises are located within the boundaries of a municipality. Id. This "retail choice" model prohibits the consumer from changing their mind, stifling interest in the program. See NREL, Corporate Renewable Energy Procurement Pathways in the Southeast: Georgia. See also Virginia Code § 56-577.

35. *See* City of LaGrange v. Georgia Power Co., 363 S.E.2d. 286, 289 (Ga. App. 1987) (dissenting opinion) (quoting the Georgia Public Service Commission); see also Sawnee Electric Membership Corporation v. Georgia Public Service Comm'n 273 Ga. 702 (2001) (holding that an apartment building with separately metered units cannot quality as a "large load" consumer).

36. North Carolina G.S. § 62-133.9(f).

37. Nevada Revised Statutes 704B, Providers of New Electric Resources.

38. Application of Switch Ltd. To Purchase Energy, Capacity, and/or Ancillary Services from a Provider of New Electric Resources, PUC of Nevada, STIPULATION, Docket No. 14-11007, July 7, 2015.

39. Virginia Code § 56-577(A), Exceptions to Monopoly Rights of Electric Utilities.

40. *See, e.g.,* North Carolina G.S. § 62-159.2; Kentucky Public Service Commission, In the Matter of: Electronic Application of Kentucky Power Company for … (3) An Order Approving its Tariffs and Riders, Case No. 2017-00179, Order (Jan 18, 2018), at 59 (approving Kentucky Power's proposal "to allow participating customers to purchase their full requirements from renewable energy generators").

41. The term "sleeved" is used because these agreements enable the large customer to reach through the utility to contract with a renewable energy generator for power.

cover administrative costs and to ensure that nonparticipating utility customers are "held neutral."[42] Even so, corporate customers see a financial advantage, as renewables now cost less than conventional power in many parts of the U.S., and because a long-term contract in renewables hedges against fuel price increases.[43] Therefore, these arrangements may help companies lower energy prices, reduce future price uncertainty, or achieve corporate clean energy or climate goals.

Thus far, these types of choice programs do not extend to smaller industrial and commercial customers or residential customers in the Southeast. Going forward, customer-focused performance metrics might be incorporated into utility rate-making incentives structures, to encourage a utility to make choices that reflect broader customer concerns or public policy preferences (particularly where these might deviate from the traditional focus on reliability at least cost). For instance, in 2018, Hawaii passed a law to offer performance-based incentives to the Hawaiian Electric Companies, including more rapid implementation of competitive procurements and integration of renewable resources and customer-sited distributed generation.[44] Other states exploring these options include Pennsylvania, Minnesota, and Colorado.[45] Decoupling a utility's profits from volumetric sales may be a useful policy complement, where it would unleash the utility's own ability to invest in demand-side and customer-sited power.[46]

Third-Party Participation

In recent years, the Southeast has made changes to utility codes, to enable third-party participation in emerging niche markets such as **rooftop solar**.

In 2015, the Georgia legislature passed the Solar Power Free-Market Financing Act,[47] following pressure by a coalition of Tea Party and Sierra Club members.[48] The legislature found that "[i]t is in the public interest to facilitate customers of electric service providers to invest in and install on their properties solar technologies of their choice," and that "[f]ree-market financing of solar technologies may provide more customers with opportunities to install solar technology."[49] That said, the legislation made clear the financing arrangements were not considered the "provision of electric service to the public."[50] Beyond the narrow exceptions created by the bill, Georgia made clear it did not intend to upset the monopoly service provisions of the utility code.[51]

In 2017, North Carolina exempted solar energy facility leasing companies from the definition of a "public utility,"[52] enabling these firms to operate alongside and in the service territories of Dominion, Duke Energy Carolinas and Duke Energy Progress. However, the Public Utilities Commission would certify and oversee each solar leasing business.[53] Leased solar systems were capped at one percent "of the previous five-year average of the North Carolina retail contribution to the offering utility's coincident retail peak demand."[54] And residential solar systems could not be used to sell power in direct competition with the public utilities.[55] Meanwhile, the Florida

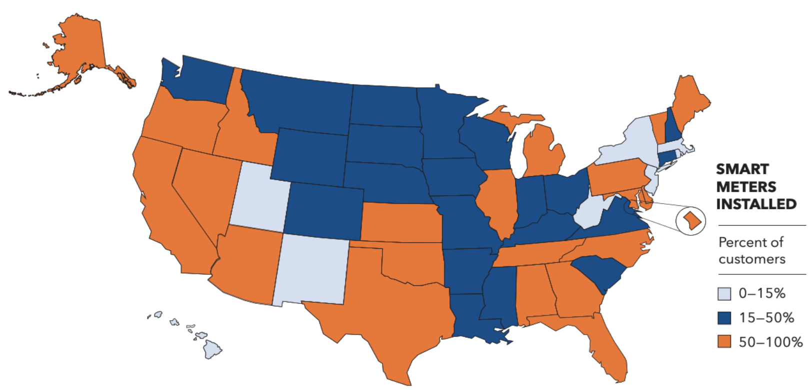
42. North Carolina G.S. § 62-159.2(e).
43. *See, e.g.,* Hannah Hunt, Utility Green Tariffs: A New Way for Fortune 500 Companies to Buy Clean Energy, Renewable Energy World, Issue 3 and Vol. 21 (June 5, 2018).
44. Hawaii S.B. 2939 (2918).
45. Chloe Holden, More States Explore Performance-Based Ratemaking, but Few Incentives are in Place, Green Tech Media (June 13, 2019); Cory Felder, Dan Cross-Call, Performance-Based Ratemaking: Getting Down to Business Model Reform in Colorado (Sept. 18, 2019).
46. For an overview of decoupling policy, *see* NREL, Decoupling Policies: Options to Encourage Energy Efficiency Policies for Utilities (2009). But see ELCON, Revenue Decoupling (opposing the policy for being too disruptive of the utility business model). For a more up to date list and map of states with decoupling policies, *see* Center for Climate and Energy Solutions, Decoupling Policies (2019).
47. Georgia Stat. § 46-3-60 et seq.
48. Michael Kanellos, Behind the Tea Party Push for Solar in Georgia, Forbes.com (July 16, 2013).
49. Georgia Stat. § 46-3-61(1), (2).
50. Georgia Stat. § 46-3-65(a).
51. Georgia Stat. § 46-3-66(a).
52. North Carolina G.S. § 62-3(23)(a)(1); 62-126.5(b).
53. North Carolina G.S. § 62-126.7.
54. North Carolina G.S. § 126.5(d).
55. *See, e.g.,* limits on eligible systems to 100% of on-site demand, § 62-126.3(14), and a prohibition on serving other premises, § 62-126.5(e). The same law authorized a 20 MW community solar program; that program is not expected to launch until at least 2021. North Carolina G.S. § 62-

Public Service Commission declared in 2018 that residential solar equipment leases are not a "sale of electricity" and therefore could proceed in monopoly utility service territories.[56] Similar arrangements might be crafted for combined heat and power (CHP) installations.

Similarly, several southeastern states have made clear that third parties may install **electric vehicle charging** equipment without having to adhere to territorial agreements or submit to utility commission regulation.[57] In some parts of the region, third parties are planning **independent electric transmission lines**; for instance, Pattern Energy Group LP is developing the Southern Cross project to bring Texas wind to the Southeast through a line along the borders of Louisiana and Mississippi.[58] While the line has faced technical and political hurdles[59] since winning approval from FERC in 2014,[60] it represents an emerging playing field for third parties in the South.

Utilities in the United States will have installed more than 100 million **smart meters** by sometime in 2020.[61] Some southeastern states have particularly high smart meter installation rates (see Fig. 2).[62] While utilities can use smart meter data to improve system operations, many residential and smaller commercial customers do not have ready access to their data to manage and reduce their energy consumption. That said, some southeastern utilities have committed to using Green Button to share smart meter data with customers, including the Chattanooga Electric Power Board, the Jacksonville Electric Authority (JEA), the Sawnee coop in Georgia, and Virginia Dominion Power.[63] Duke, meanwhile, has just launched "download my data" functionality for its customers.[64] Going a step further, Texas requires that utilities share a customer's smart meter data with third parties authorized by the customer.[65] Such authorization could enable third parties to identify energy usage trends and craft responsive products and services to fill market niches.

Figure 2. Smart Meter Deployments by State, 2018 (% of Customers)



126.8.

56. State of Florida Public Service Commission News Release, PSC Declaratory Statement Allows Residential Solar Equipment Leases (April 20, 2018).

57. *See, e.g.,* Florida 366.94; North Carolina G.S. § 62-3(23)(n); Virginia Code § 56-1.2.

58. Southern Cross, FAQ and Resources (website last visited June 28, 2020).

59. *See, e.g.,* Chris Brewster, Linking ERCOT to the Southeastern United States through the Southern Cross, Texas Coalition for Affordable Power (Mar. 16, 2020).

60. 147 FERC ¶ 61,113, Final Order Directing Interconnection and Transmission Service (May 15, 2014).

61. Adam Cooper and Mike Shuster, Electric Company Smart Meter Deployments: Foundation for a Smart Grid (2019 update), Edison Foundation Institute for Electric Innovation (Dec. 2019).

62. Id., at 2.

63. U.S. Department of Energy, Green Button Initiative (website last visited June 30, 2020).

64. *See* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Notice of Customer Data Access Functionality, Docket Nos. E-100, Sub 157 and E-7, Sub 1146 (Mar. 2, 2020).

65. Texas PUC rule § 25.130(j). As noted above, supra at 3, Arkansas has also contemplated third-party data access.

Steps needed: In some cases, state utilities commissions have approved utility proposals to offer green tariff programs to large customers (Georgia Power,[66] Dominion Energy Virginia, dba Virginia Electric & Power Company[67]) or enabled third-party participation in the solar market (Florida) under existing statutory authority. However, most of the examples here have involved legislative action. Southern legislatures have appeared open to bespoke offerings to large consumers and "competition at the margins" in the power sector, particularly for newer technologies appealing to a niche market.

Questions to be asked:

(1) Can policy makers allow large or wealthier customers to leave the utility or self-produce power, without saddling smaller or less wealthy customers with higher fixed costs?

(2) How can policy makers reduce the risk of redundancy of infrastructure as they enable third-party participation in segments of the electricity market?

(3) Do utility incentive structures need to change, to enable a utility to turn a profit alongside third party participation in or assumption of capital projects?

(4) What companion policies need to change to drive real competition? For instance, Georgia's net metering policies had been thought to deter solar installation, even after third-party leasing companies were authorized to market in that state.[68]

OPTION B: REQUIRE VIUs TO PURCHASE GENERATION FROM OTHER ENTITIES

Monopsony (noun) A market situation in which there is only one buyer.

Merchant generators can sell at wholesale to or through VIUs, even in cost-of-service states. Similarly, neighboring utilities with excess power can sell wholesale energy to each other. However, a utility may prefer to build its own generation and earn a return on equity from these capital investments,[69] rather than purchase from third parties. Since enactment of the federal Public Utility Regulatory Policies Act (PURPA) in 1978, southeastern states have required public utilities to make some third-party power purchases. However, other options exist, to require utilities to purchase from third parties or to demonstrate that building their own generation is the least-cost option.

Design Alternatives/Living Examples

PURPA requires utilities to buy power from Qualified Facilities (or QFs)—renewable energy resources and combined heat and power[70] projects under 75 megawatts in capacity—at the cost the utility avoids by not having to build that capacity. By amending the Federal Power Act with this directive, PURPA marks the first time Congress required competition in the power sector.

66. Georgia Power, Electric Service Tariff: Commercial & Industrial REDI Schedule – CIR-1 (effective January 2019); Georgia Power Commercial & Industrial Renewable Energy Development Initiative (visited June 22, 2020).

67. Virginia Electric & Power Co., Schedule RF, Environmental Attributes Purchase from Renewable Energy Facilities (Experimental) (filed Aug. 2, 2019).

68. But *see* Georgia Public Service Commission, Docket No. 42516, Short Order Adopting Settlement Agreement as Modified (Dec. 17, 2019), at 10-11 (shifting met metering from instant to monthly for first 5,000 installations or first 32 MW); Mary Landers, Rooftop Solar Gets a Boost, August Chronicle (Feb. 10, 2020) (explaining that this also increases the rate from Georgia Power's "avoided cost" to retail rates).

69. J.D. Wilson M. O'Boyle, and R. Lehr, Monopsony Behavior in the Power Generation Market, The Electricity Journal 33 (2020) 106804, at 3. The article goes on to argue that by self-supplying rather than purchasing in a more competitive environment, the utility may drive up generation costs and rates. Id., at 4.

70. PURPA, Public Law 95-617, 92 Stat. 3144; 16 U.S.C. § 824a-3(f) (directing states to implement FERC rules to encourage cogeneration and small power production).

"Avoided cost" determinations are made at the state level; there is wide variability in these processes and in the factors considered for setting avoided cost rates.[71] In this variability, states have created more or less welcoming markets for QFs. Many credit North Carolina's historic avoided cost rates[72] and standard contract offerings[73] for its high levels of installed QF capacity, earning it the second highest most installed solar capacity in the country, after California.[74]

In 2005, the Energy Policy Act created a rebuttable presumption that projects over 20 megawatts capacity can participate in FERC-designated wholesale bulk power markets.[75] (FERC recently reduced this threshold to five megawatts.)[76] Therefore, where those markets exist, PURPA may become a less important policy mechanism for introducing competition into power purchases. By contrast, in regions where RTOs do not currently exist, including in much of the Southeast, PURPA remains a primary means of diversifying power supply.

In other regions of the country, **renewable portfolio standards (RPS)** have been a common policy tool for requiring the purchase of clean power. Indirectly, in monopoly utility service territories an RPS may also encourage power purchases from third parties. Rather than having the state set the price as in PURPA avoided cost proceedings, here the state expresses a preference for clean energy and then directs the utility to build or buy those resources at market-based prices. In the Southeast, just two states have these standards in place.

The North Carolina General Assembly created the state's Renewable Energy and Energy Efficiency Portfolio Standard in 2007, in part to encourage private investment in renewable energy and energy efficiency.[77] Investor-owned utilities were required to generate renewable energy or invest in energy efficiency, purchase renewable energy, or purchase renewable energy certificates to meet a set percentage of retail sales, topping out at 12.5 percent in 2021.[78] Public power serving state load were required to meet less stringent targets.[79] Some of the carve-outs in North Carolina law describe energy resources (swine and poultry waste) that Duke Energy and Dominion did not own.[80] More recently, Virginia has enacted legislation to establish that it is in the public interest for public utilities to build *or purchase* up to 5,200 megawatts of offshore wind prior to December 31, 2034,[81] and to require public utilities to meet an RPS that increases to 100 percent of sales by 2045 or 2050, depending on utility size.[82]

A few more southeastern states enable **competitive electric procurement**, requiring monopoly utilities to go to market to procure capacity, or establish they can build the same capacity at lower cost. For instance, since 2004, Louisiana has required utilities to issue Requests for Proposal to compare those costs for new capacity to capacity they propose to build.[83] Georgia[84] and Florida[85] have similar programs. These may be referred to as

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71. *See* Victor B. Flatt, Seth Yeazal, and Miles Wobbleton, Federal Parameters on the Definition of Avoided Cost under PURPA and Legal Methods Currently Used and Acceptable under PURPA Application for States to Encourage or Discourage Distributed Generation, UNC and University of Houston (updated July 1, 2017).
72. North Carolina G.S. § 62-156.
73. North Carolina offers standard contracts for projects up to 1,000 kilowatts. North Carolina G.S. § 62-156(b)(1).
74. Solar Energy Industries Association, Top 10 Solar States (2020) (Florida and Georgia are in the top 10 as well); see also 172 FERC 61,041 (July 16, 2020), ¶ 44 (identifying North Carolina as the state with the "highest total amount of wind and solar QF capacity in the country").
75. Energy Policy Act of 2005, Pub. L. 109-58, 119 Stat. 967, 16 U.S.C. § 210(m). North Carolina law notes that investor-owned utilities would no longer be subject to PURPA purchasing requirements at all if they were to join a competitive wholesale market. North Carolina G.S. § 62-156(d).
76. 172 FERC 61,041 (July 16, 2020), ¶ 64; 18 § 292.309(c), (d), (e), and (f).
77. North Carolina G.S. § 62-2(10)(c).
78. North Carolina G.S. § 62-133.8(b).
79. North Carolina G.S. § 62-133.8(c).
80. *See* North Carolina G.S. § 62-133.8(e), (f).
81. Virginia H.B. 1526 (2020); Virginia Code § 56-585.1:11.
82. Virginia Code § 56-585.5.
83. Louisiana Market-Based Mechanism Order (General Order, Docket No. R-26172 Sub Docket A) (2004), described in Susan F. Tierney, PhD and Todd Schatzki, PhD, Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utilities Practices, Analysis Group (July 2008), at 14, Table 6.
84. Georgia Rule 515-3-4-.04(3).
85. Florida Admin. Code Ch. 25 § 22.082.

comprehensive single-source procurement processes,[86] in that they might cover any type of generation but will focus on one predetermined type in each request. Requiring utilities to compare the cost of purchasing power from IPPs or neighboring utilities to, say, building and operating peaking plants could act as a form of competition if it provides options to a utility commission considering a utility's proposed generation investments. FERC's recent PURPA rulemaking endorses all-source procurement and suggests it could be used to set avoided costs for QFs,[87] or even to terminate the PURPA purchasing obligation.[88] (See above section for more on the PURPA program.)

In other regional examples, **competitive procurement is limited to particular types of generation**. North Carolina H.B. 589,[89] enacted in 2017, requires public utilities to procure 2,660 megawatts of renewable energy and capacity from facilities no larger than 80 megawatts, over a 45-month period.[90] No more than 30 percent of this capacity can be met through facilities owned by the public utilities themselves.[91] Public utilities reserve the authority to select projects based on location.[92]

Some stakeholders have raised concerns about the true competitiveness of some procurement processes.[93] Literature suggests a number of "best practices" to expand competitive opportunities for new capacity, including providing more oversight of RFP procedures and contract terms, and running **all source procurement** processes, whereby any technology can bid in to meet a utility's energy, capacity and grid management needs.[94]

In recent years there has been a sharp increase in the amount of **distributed energy resources** generating power behind customer meters. Rooftop solar, encouraged by policies such as those described in Option A, has grown and with it, customer interest in being paid for the power they generate on their homes and businesses. **Net metering** allows a homeowner to be compensated for the net power she generates once her consumption is subtracted out. This has been treated as a retail transaction subject to state oversight, which avoids triggering federal energy jurisdiction.[95] (A similar policy was created in Georgia in 2001, to encourage behind-the-meter CHP generation.[96]) The rate of reimbursement can also drive or inhibit the rooftop solar market. Meanwhile, utilities complain that the rate they pay for rooftop power is higher than a typical wholesale rate and may not cover the costs of interconnecting the resource to the grid or maintaining that connection. This argument may concern nonparticipating customers who also fear cost shifting resulting from these arrangements.

Steps needed: All state utilities commissions are empowered by federal law to implement PURPA for smaller renewable energy and CHP projects. Where a competitive market does not exist in the Southeast, and barring any additional restrictions set on the commission by the state legislature,[97] those bodies have some latitude for encouraging or discouraging third-party generation. In addition, state utilities commissions, for instance in Louisiana, have directed utilities to issue Requests for Proposal for new capacity to determine the least-cost way of acquiring that capacity. However, requiring that a utility purchase power from a third party (beyond PURPA requirements) or setting renewable or clean energy requirements, likely requires legislative action.

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86. J.D. Wilson *et al.*, *supra* n. 26, at 2–3.
87. 172 FERC 61,041 (July 16, 2020), ¶ 411.
88. Id. ¶ 662.
89. North Carolina H.B. 589 (2017).
90. North Carolina G.S. § 110.8(a). The Utility Commission is authorized to require a second tranche of competitive procurement. Id.
91. North Carolina G.S. § 110.8(b)(4).
92. North Carolina G.S. § 110.8(c).
93. *See, e.g.,* 172 FERC 61,041, ¶ 425 (describing comments about shortcomings in current competitive procurement).
94. *See, e.g.*, *See* John D. Wilson, Mike O'Boyle, Ron Lehr, and Mark Detsky, Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement, Energy Innovation (April 2020); Tierney and Schatzki, *supra* n. 80.
95. In 2001, the Federal Energy Regulatory Commission refused to find that Iowa's approval of a utility's net metering policy was preempted by federal law. FERC Order Denying Request for Declaratory Order, 94 FERC 61,340, Docket No. EL99-3-000 (Mar. 28, 2001). In 2020, the New England Ratepayers' Association petition FERC to revisit this decision; FERC has dismissed that petition. See Petition for Declaratory Order of [NERA] Concerning Unlawful Pricing of Certain Wholesale Sales (Apr. 14, 2020).
96. *See* Georgia Cogeneration and Distributed Generation Act of 2001, Georgia Stat. § 46-3-50.
97. North Carolina H.B. 589, Sec. 1.(b) (2017); N.C.G.S. § 62-156.

Questions to be asked:

(1) What are the relative cost advantages of utilities building their own new capacity versus going to market for some or all of that capacity?

(2) If utilities are not earning a rate of return for energy purchased on the market, how does this affect their business model? What adjustments, if any, need to be made to that model?

(3) If third-party purchases are required (across the board, or upon a showing that they save the consumer money), should the state set the price or let the market decide?

(4) Should third-party procurement be limited to certain types of capacity, for instance renewable capacity or an abundant state resource, or not?

OPTION C: SHARE RESOURCES THROUGH POWER POOLS ACROSS VIUs, ELECTRIC MEMBERSHIP COOPERATIVES, AND MUNICIPAL POWER PROVIDERS IN THE REGION

What is a power pool? A power pool has been broadly described as "an association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies."[98] Duke Energy Progress and Duke Energy Carolinas are in a power pool of sorts across parts of North and South Carolina.

A power pool is an agreement between electric utilities to share resources or coordinate some aspect of their operations. These agreements may also involve planning coordination.[99] Power pools grew out of voluntary cooperation between utilities, based on a mutual interest in sharing resources.[100] Power pools can span single or multiple states. Some pools simply interconnect two or more systems for joint planning and assistance, while others use a centralized dispatch to operate as a single system.

Design Alternatives/Living Examples

In 1970, the Federal Power Commission counted 21 **power pools with formal agreements** and 13 **informal coordinating organizations** in the U.S.[101] Some pools dissolved, and others morphed into more formalized competitive markets, including PJM and the pools for New York and New England, which both formed in the aftermath of the 1965 Northeast blackout. Southwest Power Pool also later became an RTO.[102]

A number of power pools or pool-like entities have existed in the Southeast.[103] Carolina Power & Light Co., Duke Power Co., the South Carolina Electric & Gas Company, and the Virginia Electric & Power Company created a power pool in 1961. Each utility retained responsibility for its own service area. The pool established procedures for allocating shares in new generation and established rates the pool members were to pay each other in power transactions. The pool dissolved during negotiations between the Justice Department, the Atomic Energy Commission, and two of the member utilities.[104]

98. U.S. Energy Information Administration, Glossary, https://www.eia.gov/tools/glossary/index.php?id=P.
99. Additional information about power pools may be found in a companion paper, beginning on p. 18: Evaluating Options for Enhancing Wholesale Competition and Implications for the Southeastern United States.
100. The Federal Power Act does not use the term "pools" but section 202 directs the Commission "to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy" and "to promote and encourage such interconnection and coordination within each such district and between such districts." FPA section 202(a), 16 U.S. Code § 824a.
101. Federal Power Commission, 1970 National Power Survey, pt. I, ch. 17, at 2–14.
102. FERC Energy Primer at 39. These markets, known as Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), are discussed in more detail infra at 22-25.
103. Transmission, Power Pools, and Competition in the Electric Utility Industry, J. Fairman and J. Scott, 28 Hastings L.J. 1159 (1977) at 1169–71.
104. Id. at 1200–01.

More recently, Duke Energy Carolinas and Carolina Power & Light agreed to **jointly dispatch generation**[105] as a condition to the merger of Duke Energy and Progress Energy.[106] This is also a type of power pooling arrangement. Under the agreement, Duke Energy Carolinas dispatches the companies' generation resources to meet load requirements and contractual commitments subject to reliability and contractual requirements.[107] Payments are settled hourly (compared to every five minutes for more formalized markets).[108] Unit commitment is determined by a fuel systems optimization department, which procures the fuels based on a seven-day unit commitment plan.

The North Carolina Utilities Commission noted in its conditional approval of the merger that joint dispatch of DEC's and PEC's generation assets could achieve $364.2 million in total system fuel and fuel-related cost savings over the five-year period 2012 through 2016, while an additional estimated $330.7 million might be realized through sharing and implementing best practices for fuel procurement and use.[109]

Across the non-RTO Southeast, FERC reports that wholesale spot power markets are thin and price data is scarce.[110] The absence of these data can make it difficult for regulators to determine whether customers are indeed paying for lowest-cost generation and dispatch.

Southern Company operates a power pool with its affiliates Georgia Power, Alabama Power, and Mississippi Power.[111] The pool's primary function is to centrally dispatch excess resources, other than conventional hydro and nuclear power. As energy resources were obtained through bilateral transactions, energy prices and volumes are determined through contracts in advance. The centralized dispatch schedules resources according to variable costs (not generator bids), subject to constraints and obligations across the region. Transactions are settled hourly.[112]

Separate from the interchange agreement with its affiliates, Southern Company holds auctions for day-ahead and hour-ahead power within the **Southern Balancing Authority Area**.[113] "The purpose of the energy auction is to resolve perceptions that Southern Company could exercise horizontal market power through the physical or economic withholding of generation."[114] The auction is not a trading platform. Rather, it matches parties to facilitate bilateral transactions by sorting offers in ascending order and bids in descending order.[115] The website posts average hour-ahead purchases and sales a day after the transactions.[116] Auction activity has been sparse since its inception in 2009.[117] For most days of the year, the auction does not report any transactions. Nearly all of the data is redacted in the public version of the market monitoring report.[118]

105. Joint Dispatch Agreement between Duke Energy Carolinas, LLC and Carolina Power & Light Company.

106. Duke Energy Corp. and Progress Energy, Inc., 139 FERC ¶ 61,193 (2012), order denying reh'g, 151 FERC ¶ 61,242 (2015), order on remand, Orangeburg, S. Carolina v. FERC, 862 F.3d 1071 (D.C. Cir. 2017), order on remand, 166 FERC ¶ 61,112 (2019).

107. Duke Energy, 166 FERC. ¶ 61,112, at p. 12.

108. Joint Dispatch Agreement Between Duke Energy Carolinas, LLC Carolina Power & Light Company (2011) at 7–10.

109. NCUC Order on Merger at 17. These savings are bounded by the limits of physical transmission facilities, transfer capabilities, and constraints. Id., at 30. See also Duke Energy Merger Benefits Begin Flowing to Carolinas Customers (merger applicants committed to "deliver $650 million in savings to customers over the next five years").

110. FERC Energy Primer 2020 at 71.

111. The Southern Company pool does not include all of the entities in the Southern Company balancing authority. Southern Company System Intercompany Interchange Contract (2007).

112. Id. at 23.

113. Southern Company, General Auction Information (website last visited July 3, 2020).

114. Id.

115. Technical Conference Presentation of Southern Companies (May 2016). In this way, the auction serves a similar purpose as the now defunct Florida Energy Broker. For more information on this broker model, see Florida Public Service Commission, Electric Restructuring Details (website last visited July 3, 2020).

116. See, e.g., Southern Company, Announcement (Feb. 21, 2017).

117. FERC Energy Primer at 68. Also Order on Updated Market Power Analysis, Instituting Section 206 Proceeding (Apr. 27, 2015) (justifying the investigation on the "limited number of transactions cleared in the Auction, the limited number of participants in the Auction, and Southern Companies' high prices for sales relative to other sellers' prices in the Southern balancing authority area").

118. *See, e.g.,* Tenth Annual Informational Report of the Independent Auction Monitor (Jun. 28, 2019).

In July 2020, news outlets reported that Southern Company has been leading negotiations with nearly 20 investor-owned, municipal, and rural electric cooperative utilities in the Southeast to offer a platform for 15-minute sales of power across the region.[119] The concept for the **Southeast Energy Exchange Market** (or SEEM) had not been fully outlined as of this writing, but appears to ensure continued "complete autonomy" for participating utilities[120]—they would neither reserve transmission carrying capacity for the regional pool nor submit to an independent grid operator. It also seems unclear whether independent power producers would be invited to participate. As such, the proposal appears less formal than the market structures described in the next two sections of this paper.

While the previous paragraphs focused on pools that share energy resources, some vertically integrated utilities also share reserves. The North American Electric Reliability Corporation recognizes reserve sharing groups for contingency, frequency response, and regulation reserves.[121] Duke Energy Progress, Duke Energy Carolinas, Santee Cooper, South Carolina Electric & Gas, and Dominion Virginia Power are part of a **contingency reserve sharing group**. Together, these utilities keep enough reserves online to replace the largest power plant on the system should it fail.[122]

Steps needed: The steps required to form a power pool will depend in part on the degree to which the proposed pool will trade across state lines and whether utilities involved are state- or self-governed.

Historically, some negotiated multiparty agreements have been filed for approval under Federal Power Act section 202(a) as voluntary interconnections. Pooling or joint dispatch agreements that establish rates and charges for services exchanged by members can require a rate schedule filing under section 205 of the Federal Power Act. Proponents of SEEM appear to be contemplating submittal of a 205 filing with FERC, for instance. By contrast, some informal power pooling agreements were effectuated with a handshake.[123]

VIUs other than public power and rural cooperatives are generally regulated by their state legislatures and public utilities commissions. However, whether pooling actions will require regulatory approval depends on the state. For example, the reserve sharing between utilities in the Carolinas required affirmative approval from the South Carolina regulators but not from North Carolina.[124] Meanwhile, the North Carolina Utilities Commission required written notice from the IOUs before they filed with FERC, per a settlement related to the DEC-DEP Joint Dispatch Agreement.[125] Even where a state utility commission does not require up front approval of an agreement to exchange power or share reserves, a utility may seek this permission to better ensure recovery of associated costs down the line.

Questions to be asked:

(1) What products and services would be desirable to share between utilities and to what extent?

(2) When resource sharing has been voluntary, the extent of sharing has been low. What are the reasons for this? Could changes to a power pool's operation or structure change this outcome?

(3) What level of energy or reserve sharing would be necessary, to achieve policy objectives, whether cost savings, avoided new capacity, or reduced curtailment of renewables?

(4) Should transmission planning be coordinated?

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119. *See, e.g.,* John Downey, How Duke Energy Could Join Other Power Giants to Remake Southeast Markets, Charlotte Business Journal (July 17, 2020); Iulia Gheorghiu, Duke, Southern Plan Path for Southeast Energy Imbalance Market, UtilityDive (July 14, 2020).

120. *See* Downey, supra n. 114 (attributing this characterization to Noel Black, Vice President of Regulatory Affairs at Southern Company).

121. *See, e.g.,* NERC, Reliability Guideline, Operating Reserve Management recognizing these three types of reserve sharing groups.

122. *See* PJM Manual 12 Balancing Operations Revision: 38 (Apr. 20, 2018) (discussing VACAR reserve sharing) at 44.

123. Nodal Governance of the US Electricity Grid, A. Gocke (2019) at 228.

124. John Downey, S.C. Approves Plan for Duke Energy Subsidiaries to Share Power Reserves, Charlotte Business Journal (June 20, 2014); South Carolina Code §58-27-990 (requiring Commission approval for contracts between electric utilities).

125. STATE OF NORTH CAROLINA UTILITIES COMMISSION RALEIGH DOCKET NO. E-2, SUB 1095A DOCKET NO. E-7, SUB 1100A DOCKET NO. G-9, SUB 682, Regulatory Conditions and Code of Conduct at 5-6.

OPTION D: OPERATE AN ENERGY IMBALANCE MARKET THROUGH A NEIGHBORING COMPETITIVE POWER MARKET FOR VOLUNTARY PARTICIPATION BY UTILITIES

What is an EIM? An energy imbalance market or service (EIM/EIS) is a voluntary market for dispatching real-time energy across utility service territories. Each participating utility retains ownership and control of its transmission and distribution assets but chooses to bid generation into a centralized dispatch authority. There have been two examples of these types of markets in the U.S.—both were operated by independent grid operators that allow nonmember utilities to voluntarily trade energy. In addition, in 2021, the SPP grid operator plans to launch a new energy imbalance service market.

The next more formal arrangement for the joint dispatch of real-time energy involves an Energy Imbalance Market (EIM) or Energy Imbalance Service (EIS). While these markets might fall into the broader term "power pool," the EIM/EIS model generally describes a more formalized arrangement yielding transparent price signals that are spatially and temporally specific. Moreover, to date in the U.S., EIM/EIS have been operated by independent grid operators.

That said, the EIM/EIS does not require that the participating utility join a market and cede control over its transmission to the independent grid operator. Participating utilities are typically vertically integrated and retain operational control over their resources and transmission.[126] In addition, utility borders don't have to be contiguous to participate. However, participating utilities can contribute reserved transmission capacity to the EIM, and unreserved capacity is made available for real-time EIM transfers.

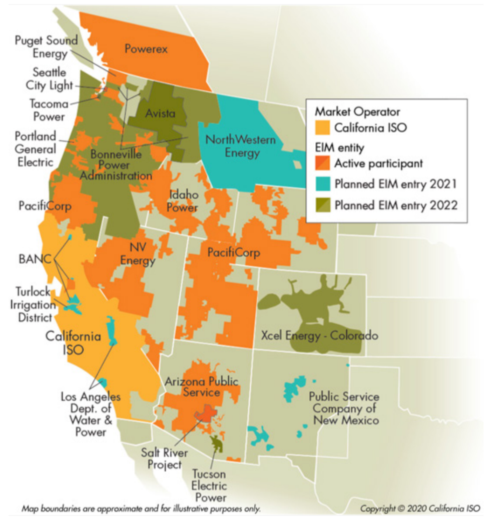
The grid operator running an EIM/EIS handles dispatch, transmission congestion management, pricing, settlement, and market monitoring associated with running a real-time energy imbalance market. All other grid operator functions are retained by the participating utilities.

Design Alternatives/Living Examples

Two EIM/EIS have operated to date in the U.S. The primary example today is the **Western EIM operated by CAISO**. The Western EIM includes more than 20 current and prospective utilities. Collectively, these entities serve over 75 percent of the load in the Western Electricity Coordinating Council (WECC).[127]

126. Additional information about EIM/EIS may be found in a companion paper, beginning on p. 15: Evaluating Options for Enhancing Wholesale Competition and Implications for the Southeastern United States.
127. WESTERN EIM BENEFITS REPORT Third Quarter 2019 at page 19.

Figure 3: Map of Current and Planned Participants in Western Energy Imbalance Market[128]



The Western EIM balances supply and demand over 5- and 15-minute intervals. In addition, there are discussions afoot to add a day-ahead market.[129] Day-ahead unit commitment and scheduling across a larger footprint boosts regional cooperation and can enable higher penetration of renewables.[130]

The second example of an EIM/EIS in the United States was **the EIS that SPP operated in the Eastern Interconnection** until 2014, when the service was incorporated into SPP's Integrated Marketplace, which now features a real-time and day-ahead energy market.[131] Looking forward, **SPP is launching a new EIS for utilities in the Western Interconnection** that will provide a real-time balancing market starting in early 2021.[132] Consistent with the CAISO EIM, utilities will not have to become members of SPP to benefit from its central dispatch. Each utility will remain responsible for committing generation to meet its real-time obligation to balance their customer demand and resources in their footprints. Basin Electric Power Cooperative, Tri-State Generation and Transmission Association, Wyoming Municipal Power Agency, Municipal Energy Agency of Nebraska, and components of the Western Area Power Administration have announced they are joining SPP's new contract service.

While certain southeastern utilities already share excess energy, the volumes traded are modest and trades do not yield transparent price signals. Nor is there an open "market" where nonutility generation might compete. The private **SEEM negotiations** suggest regional utilities are exploring how to formalize or increase these exchanges. Some stakeholders are pushing for a market design that would open the market to independent power producers, and identify a neutral, independent entity to perform central dispatch functions.[133] In fact,

128. Western Energy Imbalance Market (website last visited July 30, 2020). Permission to republish granted by CA-ISO.
129. Extending the Day-Ahead Market to EIM Entities Issue Paper (Oct. 10, 2019) Presentation (Oct. 17 2019).
130. Robert Walton, CAISO to Develop Regional Day-Ahead Market for Renewables after Participant Push, UtilityDive (Sept. 23, 2019).
131. The Power of Relationships - 75 Years of SPP, N. Sawyer and L. Dillahunty (2016), p. 124; SPP, Integrated Marketplace (last visited July 30, 2020).
132. Southwest Power Pool, Western Energy Imbalance Service Market website (last visited July 23, 2020).
133. *See, e.g.,* Maggie Shober, Southern Alliance for Clean Energy, Potential Energy Market in the Southeast? What We Know So Far About SEEM (July 17, 2020); Steven Shparber, Southeastern utilities' energy market proposal appears to be less than it may SEEM, UtilityDive (July 30, 2020).

there may be market power hurdles to clear with federal authorities, if Southern Company proposes to run the regional exchange.

An alternative design could involve **individual southeastern utilities joining an EIM/EIS organized by a neighboring RTO**, following in the footsteps of the CAISO and SPP examples. These markets do not by definition need to be contiguous with southeastern utilities but that can reduce transmission costs. For instance, if TVA or Associated Electric Cooperative were to consider participating in an energy imbalance market, that might open the door for a Midcontinent ISO(MISO)– or SPP-run EIM/EIS that would extend into the Southeast. Alternatively, PJM connects to North Carolina and Kentucky, and so could potentially offer a real-time market to utilities in those states, and then to their neighbors.

Steps needed: If a new EIM/EIS were to be stood up, the independent market operator or group of proponent utilities would need to seek approval from FERC. Then, joining a new EIM/EIS would likely begin with similar steps outlined by the Western EIM for prospective utilities.[134] First, each utility might perform a cost-benefit study. Second, it develops a joint implementation agreement with the EIM to file with FERC. There are a number of steps that follow to establish operating procedures, provide training, and so on.

State-regulated utilities also need state commission approval before applying to join the EIM.

Questions to be asked:

(1) The success of the EIM/EIS in reducing wholesale costs and renewables curtailments depends on the level of market participation, as well as the transmission capacity contributed by participants. Would a platform offered by an independent grid operator encourage voluntary trading beyond what is seen today in the Southeast?

(2) The cost savings from EIM/EIS arises from dispatching lower cost resources to meet demand, such as wind or solar energy that otherwise would be curtailed. Would the participation of southeastern utilities in the proposed EIM/EIS produce a diversity of resources and load? Would that produce customer savings and emissions reductions?

(3) These questions may depend on which independent grid operator offers the EIM/EIS, which utilities join, and whether there is a day-ahead as well as a real-time imbalance market. What would work well for interested utilities and states and what market products would be available?

(4) Who can participate in the EIM/EIS? Just VIUs, or independent power producers as well?

(5) What type of stakeholder process or governance structure will be put in place?

134. Western Energy Imbalance Market, Join EIM (last visited July 19, 2020).

OPTION E: ENCOURAGE OR DIRECT VIUs TO PARTICIPATE IN AN ORGANIZED WHOLESALE MARKET BY FORMING OR JOINING AN RTO/ISO

What is an RTO/ISO? Regional Transmission Operators (RTOs) or Independent System Operators (ISOs) are typically nonprofit entities that independently manage the transmission system of participating utilities. RTOs/ISOs run markets that dispatch energy subject to economic and reliability constraints. Generation that is less flexible may also self-schedule to continuously run. RTOs/ISOs sometimes also run capacity, regulation or other markets related to grid operation. FERC has encouraged the creation of RTOs/ISOs but has not required them.[135]

RTOs independently manage the transmission system owned by member utilities. And, they balance electricity supply and demand in their real-time energy markets by dispatching the least-cost resources every five minutes over the system. Independent operation is intended to eliminate transmission-owning utilities from discriminating against competitors to their generation-owning affiliates. Some RTOs run capacity markets as well (i.e. markets where sellers commit to provide electricity in the future). These may be voluntary, as in the MISO, or mandatory, as in PJM, NYISO and ISO New England. VIUs in these markets maintain their own capacity planning to meet state regulatory requirements. VIUs also retain their own captive customers—RTO membership does not change that. RTO membership could make it less costly for IPPs to develop within the VIU's service area and sell services through the RTO markets.

In the 1990s, FERC issued Orders 888 and 889, suggesting "independent operators" as one way for existing tight power pools to provide nondiscriminatory access to transmission. Subsequently, in Order 2000, FERC encouraged the voluntary formation of RTOs to administer regional transmission grids. FERC Order 2000 did not require the utilities to form or join RTOs, although it did require consideration of the option. FERC has not been prescriptive in market design details apart from identifying the following minimum characteristics: independence from market participants; appropriate scope and regional configuration; possession of operational authority for all transmission facilities under the RTO's control; and exclusive authority to maintain short-term reliability of the grid.[136]

As noted in our companion case study, four proposals including southeastern utilities were submitted to FERC. One eventually became the basis for Arkansas/Entergy joining SPP. FERC approved two others on a provisional basis—GridFlorida, and GridSouth in the Carolinas—but raised concerns about independence from the transmission owners and the markets' narrow geographic scope. In fact, FERC ordered these market proponents to mediation with Southern Company and TVA to forge a larger market. These efforts failed, and California's energy crisis dimmed further hope of serious discussions in the region.

In addition, Virginia Power (now known as Dominion), AEP, Entergy, Consumers Energy, and Detroit Edison organized to form Alliance RTO in June 1999. If Alliance RTO had been approved, it would have been the largest RTO in the U.S. Yet FERC rejected this proposal because the members were not contiguous—not only did this raise reliability concerns, but it might drive up the RTO's transmission pricing because of pancaking—the term used to describe the stacking up of service charges when a transmission path crosses wires owned by different companies.[137]

Design Alternatives/Living Examples

Southeastern VIUs could follow other regional utilities into one of two contiguous markets: PJM or MISO. Two case studies illustrate this option. First, following legislation requiring Virginia's regulated utilities to join or

135. RTO and ISO functions are similar, and for most purposes, the distinction is irrelevant. We will refer to both entities as "RTOs" in this paper.
136. FERC Order 2000, Regional Transmission Organizations, 89 FERC ¶ 61,285 (Dec. 20. 1999). The Order also lists and describes eight minimum functions. Id.
137. *See, e.g.,* Report of the Legislative Transition Task Force Established under the Virginia Electric Utility Restructuring Act, Senate Document No. 54 (2000), https://rga.lis.virginia.gov/Published/2000/SD54/PDF.

create a Regional Transmission Entity by 2005,[138] **Dominion filed for approval to join PJM** from the Virginia State Corporation Commission (SCC).[139]

Dominion submitted a cost-benefit analysis that estimated Dominion's participation in PJM would result in 10-year savings to Virginia retail customers of as much as $477 million. The SCC found that the cost/benefit studies submitted by Dominion and SCC staff "do not establish a significant economic detriment" and approved Dominion's proposal in November 2004.[140] Evidence later suggested greater savings; for instance, Dominion's economy energy purchases from PJM's day-ahead market saved about $75 million in 2013 alone, compared to if Dominion had self-generated the same energy.[141]

FERC approved Dominion's entry into PJM in October 2004.[142] Today, Dominion bids its entire load into the capacity market as a load-serving entity and sells all its capacity in the PJM capacity market as a generation owner. Per Virginia law, Dominion's revenues in PJM's capacity market are netted against its capacity purchase costs and may be considered in setting Dominion's base rates at retail. Dominion's costs and revenues from off-system energy sales are considered in Dominion's fuel cost recovery charge, and Dominion is generally allowed to keep 25 percent of the profit from these sales.[143] The VIU continues to engage in state integrated resource planning and to seek certificates of public convenience and necessary for new capital investments.

The second Southern example of RTO participation was **Entergy's decision to join MISO**. Entergy's action was initially prompted by pressure from federal and state regulators as well as the U.S. Department of Justice, stemming from market power concerns. Over the course of a decade, Entergy considered several options before joining MISO.[144]

In 2011 and 2012, Entergy and MISO filed for FERC approval of Entergy's entry into MISO. FERC approved the arrangement with minor conditions.[145] The Arkansas Public Service Commission also approved the proposal,[146] after extracting a concession to empower the Organization of MISO States (OMS) to develop their own transmission cost allocation as an alternative to any MISO proposal filed at FERC.[147] This suggests that states have leverage during these approval processes to shape the role they will play going forward.

Entergy joined MISO in December 2013. Entergy has estimated the five-year savings realized by its customers from joining MISO to be about $1.3 billion, an average of $261 million annually.[148]

Alternatively, **southeastern utilities could create their own RTO**. Based on FERC applications in 2000, such a scheme would likely need to extend across most of the parts of the Southeast currently unaffiliated with a bulk power market, to overcome market power concerns. Moreover, at that time FERC directed the removal of a VIU

138. VA Code § 56-579. Regional transmission entities.
139. Dominion Energy News Releases, Dominion Applies to Join PJM Interconnection (June 27, 2003).
140. STATE CORPORATION COMMISSION AT RICHMOND, NOVEMBER 10, 2004 COMMONWEALTH OF VIRGINIA, ex rel. STATE CORPORATION COMMISSION CASE.
141. *See* Direct Testimony of Alan Meekins, on Behalf of Virginia Electric and Power Company before the State Corporation Commission, at 14-17.
142. PJM Interconnection, L.L.C. and Virginia Electric and Power Company, 109 FERC ¶ 61,012 (2004), order on reh'g, 110 FERC ¶ 61, 234 (2005). FERC approved the application of American Electric Power (AEP), another Virginia utility, to join PJM in April 2003.
143. § 56-249.6. Recovery of fuel and purchased power costs.
144. Reuters, Timeline - Entergy Transition to MISO. See also EIA, Today in Energy (Oct. 24, 2013). DOJ Statement on Entergy's Transmission System Commitments.
145. FERC approved various aspects of the proposal in concurrent, related proceedings, including MISO, 139 FERC ¶ 61,056, Docket No. ER12-480-000 (2012), order on reh'g, 141 FERC ¶ 61,128 (2012), order on reh'g, 144 FERC ¶ 61,020 (2013). See also, e.g., ITC Holdings Corp. and Entergy Corp., 143 FERC ¶ 61,256, Docket No. EC12-145-000 (2013).
146. E.g., PR Newswire, APSC Conditionally Approves Entergy Arkansas' Move to MISO; see also Arkansas PSC allows MISO to assume functional, operational control of Entergy Arkansas' transmission facilities | Transmission Intelligence Service.
147. J. Chen and G. Murnan. State Participation in Resource Adequacy Decisions in Multistate Regional Transmission Organizations, at pp. 9-10. NI PB 19-03. Nicholas Institute for Environmental Policy Solutions, Duke University. This paper also discusses a broader role for State regulators in SPP.
148. Entergy Customers Realize Significant Benefits After 5 Years as MISO Member.

executive as Chief Operating Officer of the Carolinas market,[149] and rejected the Southern Company proposal, which in include the affiliates' power to hire and fire their Independent System Administrator.[150] Therefore, a Southern RTO would need to be sure to include the hallmarks of independence. Finally, based on FERC's recommendation to the proposed Florida grid operator, a robust stakeholder engagement process would likely be necessary.

Steps needed: Joining or forming an RTO will require FERC approval, as well as state public utility commission approval (because membership will require a transfer of control over transmission assets).[151] Some of these approval processes can involve settlement proceedings, which can enable parties to negotiate and tailor conditions to address their concerns. States can require utilities to join RTOs or require or authorize related PUC action through legislation.[152] FERC or the U.S. Department of Justice may also compel utilities to take actions like joining an RTO to mitigate market power concerns, for instance as a condition to a merger.

Questions to ask:

(1) What are the transition costs for the utilities to join or form an RTO?

(2) What are the projected benefits?

(3) Would VIUs joining or forming an RTO still have PURPA QF purchase obligations, and under what conditions? FERC determined that RTOs/ISOs are all competitive markets as described under section 210(m) and participating utilities would be presumptively relieved of purchasing QFs under 20 MW. A new FERC proposed rule lowers that threshold to 5 MW.[153]

(4) How would policies on reliability, GHG emissions, and innovation of the power sector interplay with the markets?

(5) What are the costs and benefits of joining an RTO with a mandatory capacity market? If a state prefers its utilities to not participate in these markets, can it use existing carve-out mechanisms, or would it have to negotiate new ones?

OPTION F: RESTRUCTURE UTILITIES

What is restructuring? Restructuring laws passed by states enable fuller competition in the generation of electricity and in nearly all cases, the wholesale procurement of electricity for resale to retail customers. In most but not all of these states, the laws also required VIUs to break apart so that independent power producers were on more equal footing when competing with incumbent actors in each industry segment. Despite the complementarity of Options E and F, they do not always coexist. Many VIUs in cost-of-service states participate in markets. By contrast, it is highly unusual for a state to restructure its utility industry and not direct or approve utility participation in an RTO.

Restructuring creates competitive opportunities in generation and sometimes, in retail sales. Restructuring laws facilitate more competitive sourcing of electric energy than PURPA, RPS, or competitive procurement laws have

149. 96 FERC ¶ 61,067 (July 12, 2001), at 4.

150. Southern persisted with this design feature in mediation with other Southern utilities over a regional RTO. *See* Mediation Report, FERC Docket No. RT01-100-000 (Sept. 10, 2001).

151. *See, e.g.,* N.C. Gen. Stat. § 62-111(a). In 2004, Dominion sought permission under this part of North Carolina law before transferring control of its transmission assets in that state to PJM. NCUC Docket E-22, Sub 418 (2004).

152. *See, e.g.,* VA Code § 56-579 (requiring utilities to join an RTO); NC House Bill 958 (proposed legislation requiring state consideration of an RTO); South Carolina Bill 4940 (2019) (same).

153. *Supra* at 13, n. 78.

otherwise produced. Moreover, in about a dozen states including California and Texas, restructuring extends to the retail business.[154] The Texas legislature found that:

> The production and sale of electricity is not a monopoly warranting regulation of rates, operations, and services and that the public interest in competitive electric markets requires that, except for transmission and distribution services and for the recovery of stranded costs, electric services and their prices should be determined by customer choice and the normal forces of competition.[155]

Many state restructuring laws came about as the federal government was seeking to open up transmission lines to third-party sales. Thus, for instance, California's 1996 restructuring law also created the California ISO to run a market and operate the state's transmission system.[156]

Design Alternatives/Living Examples

Many restructuring laws **required utilities to shed generating assets**.[157] By contrast, California's biggest utilities remain vertically integrated, although Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and the others purchase a great deal of their supply from third parties. State restructuring laws also contain different provisions regarding transition procedures and the costs of transition that can be assessed to the end-use customers, rate caps, and tax treatment of new entities post-restructuring.[158]

Power sector restructuring south of the Mason-Dixon line has taken place in Maryland,[159] Arkansas,[160] and Texas.[161] However, additional states in the region have considered this competition option. The NC General Assembly looked at full restructuring in the late 1990s,[162] but efforts were stopped short by the California energy crisis in the early 2000s. The Virginia General Assembly enacted the 1999 Restructuring Act, which also directed Virginia utilities to join an RTO by 2005.[163] By 2007, the political winds had changed; the General Assembly re-regulated the power sector, although it left the RTO membership requirement in place.[164]

Restructuring laws also enable varying degrees of **retail choice**. Most state restructuring laws that allow customers to select their electric service provider still assign customers a default utility.[165] In these cases, the customer has to actively opt out of this service to enter the competitive retail market. Some, like Maryland, then phased in choice.[166] By contrast, in Texas there is no default provider, making retail choice mandatory.

Steps needed: Legislative action would be needed to implement restructuring.

Questions to be asked:

(1) What roles remain for regulators, to protect consumers, ensure system reliability, and address externalities such as air and water pollution?

(2) What are the transition costs for utilities that restructure?

154. Id.; *see* also Texas Public Utility Regulatory Act, Tit. 2, Chapter 39.
155. Texas Public Utility Regulatory Act, Tit. 2, Sec. 39.001.
156. California AB 1890 (Sept. 23, 1996).
157. *See, e.g.,* Maryland Public Utilities Code § 7-505(b)(10)(iii) but see 7-508 (enabling the spin-off of generation assets to affiliates).
158. *See, e.g.,* Connecticut General Assembly, Office of Legislative Research, Re: Restructuring Legislation in Other States (Jan. 16, 1998) (describing different cost recovery and consumer protection provisions in other state laws).
159. Maryland Public Utilities Code § 7-501 et seq.
160. Arkansas SB 791 (1999).
161. Texas Utilities Code Sec. 39.001 et seq.
162. *See* Joint Legislative Study Commission on the Future of Electric Service in North Carolina: https://ncleg.net/Library/studies/1998/st11443.pdf; Nicholas Institute Competition Case Study – the Southern Grids.
163. Virginia SB 1269 (1999), Electric Utility Restructuring Act.
164. *See* GreeneHurlocker, Guide to Electric Utility Regulation in Virginia, 2d ed. (updated with 2018 amendments) for more information on this history.
165. U.S. EIA, Electricity Residential Retail Choice Participation Has Declined Since 2014 Peak (Nov. 8, 2018).
166. Maryland Public Utilities Code § 7-510.

(3) How can the state protect against favorable treatment for affiliates and prevent market power?

(4) If retail choice is implemented, should consumers be assigned a default provider, or should they have to choose to opt out of coverage by the incumbent provider? What rules should be put in place to protect customers from overly aggressive marketing or scams?

CONCLUSION

Options to introduce more competition on retail and wholesale range in degree and may be layered. Understanding this enables a more nuanced conversation about the future of the power sector, based on what it is stakeholders are trying to achieve and the mechanisms—transparency, innovation, resource sharing, regional grid management, emissions reductions or customer choice—to realize these goals. Thinking through what is feasible, how options might be evaluated, and whether some outcomes might foreclose other options, may create the space for real dialogue and new solutions to emerge that can garner broad appeal.

Competition is not a binary choice. By understanding the different permutations of competition and mapping state and regional policy goals over these options, states, utilities and other stakeholders can engage in productive conversations about large and small changes that might benefit utilities, independent power producers, and ratepayers in the Southeast.