State-Level Planning for Decarbonization: Critical Elements of Effective State Action

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Executive Summary

All over the United States, state governments are pursuing decarbonization on their own and in concert with other states. Much of this effort has focused on the electricity sector, where decarbonization will require investment in clean generation and transmission and a bigger focus on demand management. On April 5, 2022, the University of Virginia, the National Renewable Energy Laboratory, and Resources for the Future gathered experts to discuss the unique barriers that states face as they work toward electricity decarbonization.

Three important institutional issues arise when pursuing subnational climate policy: coordination, authority, and expertise. Coordination among a large number of states (and other jurisdictions) is challenging even when the costs and benefits of acting are confined to the jurisdictions involved. For decarbonization, with costs and benefits shared both among and beyond the acting states, the transaction costs of coordination can be expected to rise rapidly. Such problems exist within states as well, as effective decarbonization policies require actions across traditionally independent lines of agency authority. The difficulty of inducing cooperation across agency lines of authority presents a substantial friction that can slow the drive to decarbonization. Add to this the important role of regional Independent System Operators (ISOs) and other nonstate actors, and the coordination problems for state-level action can appear daunting indeed.

The federal structure of authority in the US limits the range of state action. US states, as with subnational jurisdictions everywhere, have limited authority, especially in addressing problems that cross state lines, and they are also limited in the ways in which they can cooperate.

Finally, large economies of scale exist in developing the expertise and institutional capacity needed to address the challenge of global warming. Once again, coordinating investments in new knowledge and expertise among the states would probably yield large gains, but allocating costs and benefits across jurisdictions poses significant challenges.

For clean generation investment, barriers include market structures that disfavor renewable energy resources, backed-up interconnection queues, local siting opposition, policy uncertainty, and challenges in arranging for efficient procurement of clean power. Barriers to needed transmission investment include institutional mismatch between state agencies and Regional Transmission Operators (RTOs) with authority over transmission, difficulty agreeing on cost allocation for interstate and interregional transmission, insufficient state government capacity for studying and engaging with the planning process, and local opposition. Demand management is hampered by lack of access to energy efficiency for low-income households and renters, inadequate metrics for energy efficiency, inadequate price incentives for consumers, incomplete incentives for utilities and transmission investors, and inequitable and confusing rate structures. Workshop participants suggested ways that states can engage with the Federal Energy Regulatory Commission, RTOs, state public utilities commissions, other state agencies, regulated utilities, independent power producers, and local governments to address these barriers. Participants also suggested many promising areas for future research that academics, state and federal agencies, national labs, and independent research organizations can address to help states move toward electricity decarbonization.

Contents

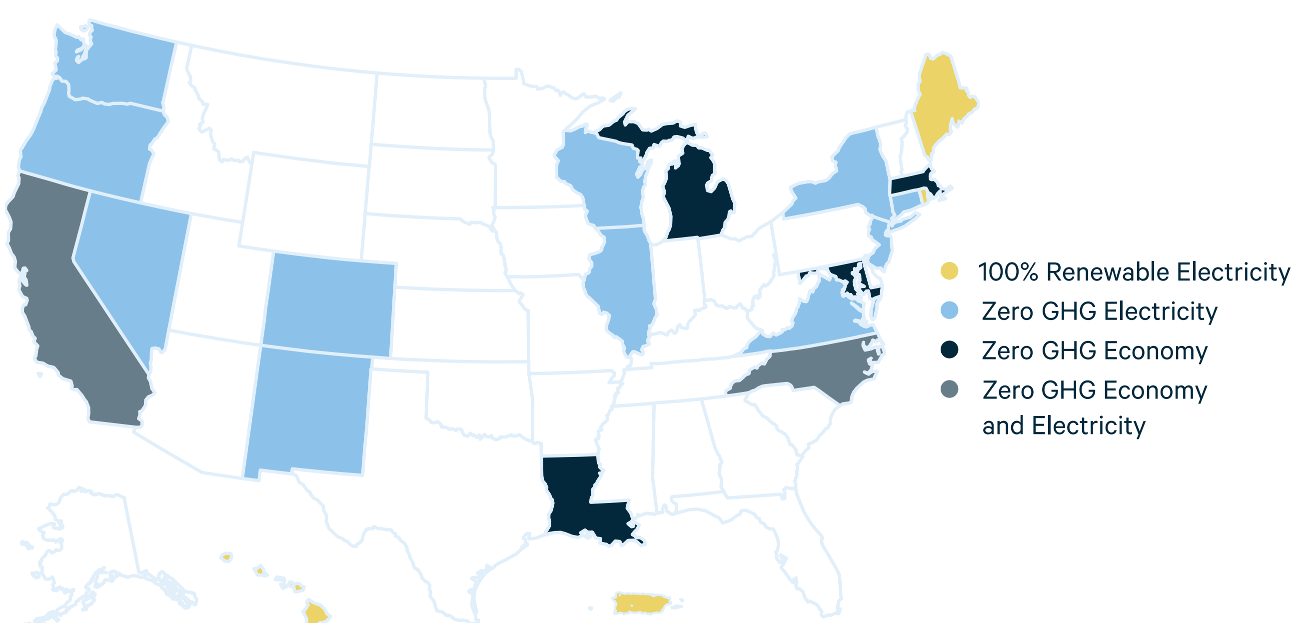
1. Introduction

Spurred by the climate crisis as well as local environmental and economic priorities, states have been developing and pursuing decarbonization commitments (Figure 1). These commitments vary considerably by jurisdiction along several metrics: the timeline of ambitions; whether commitments cover the whole economy or just specific sectors (e.g., electricity or transportation); the types of policies leveraged to drive sectoral change (e.g., for the electricity sector, capacity procurement mandates, renewable portfolio standards [RPSs], clean energy standards, clean peak standards, and emissions caps); and which technologies are eligible for meeting goals (e.g., solar, wind, nuclear, hydropower, biomass; in-state generation only or out of state as well). Decisions on these points have important implications for how states pursue their goals and the associated costs (Blanford et al. 2021).

On April 5, 2022, the University of Virginia (UVA), the National Renewable Energy Lab (NREL), and Resources for the Future (RFF) convened experts to discuss critical barriers states face when pursuing electricity decarbonization. The workshop focused on clean generation investment, transmission, and demand management and explored how interactions between federal, regional, state, and substate institutions affect state efforts. The workshop asked the following questions:

- What models of progress in these areas (clean generation procurement, transmission, demand management) currently exist? What lessons can be applied to other states with similar contexts?

Figure 1. States with electricity sector & economy-wide zero carbon goals, 2030–2050



Source: Clean Energy States Alliance, 2022.

- What are the critical barriers facing state policy and decisionmakers in each area?
- How can states effectively facilitate partnerships across agencies within state government and with the institutions implicated in electricity planning to reach their goals?[1]
- What are the most pressing research questions that need to be addressed to support states in each of these areas?

Throughout the workshop, participants focused on the institutional barriers and solutions to (a) develop feasible, achievable goals; (b) pursue cost-effective solutions; and (c) ensure meaningful progress on emissions reductions. The first requires increasing state administrative capacity and internal coordination. This means tasking agency personnel with proactive planning and making sure all agencies are planning for decarbonization together. Energy agencies can take on more responsibilities around energy and transmission planning but must work closely with environmental, transportation, and economic development agencies. Given the distributed nature of renewable resources, coordinating with local governments is also essential. Pursuing cost-effective solutions requires coordination between state and nonstate institutions to overcome the mismatch between institutions that have authority over particular aspects of decarbonization and state-level policy goals. For example, the Federal Energy Regulatory Commission (FERC) and the Regional Transmission Operators (RTOs) have significant authority over transmission planning, but states will need to work with them and their neighbors to accomplish the transmission projects that will help them meet their decarbonization goals cost-effectively. Ensuring meaningful progress on emissions reductions also requires expanded administrative capacity and coordination. If states want to avoid emissions leaking from one jurisdiction to another, they need agencies that can effectively measure leakage and interstate economic connections to understand and compensate for differing levels of ambition in neighboring jurisdictions. For example, if a state plans a stringent emissions cap but neighboring states do not, the first state must decide how to account for emissions from imported power.

This report is divided into three sections for the three sessions of the workshop: clean generation investment, transmission, and demand management. Each section summarizes the challenges, solutions, and open research questions raised by these aspects of electricity decarbonization, although many of the issues cut across multiple categories. This document does not cover all decisions states face as they pursue electricity decarbonization; it should be understood as a summary of workshop discussion and jumping-off point for future investigation.

1 These institutions include the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Regional Transmission Operators, incumbent utilities and new providers, Public Utility Commissions (PUCs), state energy agencies, state environmental agencies, local governments, and neighboring states.

2. Clean Generation Investment

As states begin to decarbonize their electricity sectors, most policy effort has focused on increasing low-carbon generation. States have done so using a variety of policy tools, often employing multiple tools at once. Table 1 includes a brief description of these policies:

Table 1. Example State Decarbonization Policies

Policy	Description	Example States
Renewable Portfolio Standard (NREL 2022)	Requirement that a percentage load be met with renewable generation, typically enforced by requiring distribution utilities to surrender Renewable Energy Credits (representing a MWh of renewable generation) equal to a percentage of their load	AZ, CA, CO, CT, DC, DE, HI, IA, IL, MA, MD, ME, MI, MN, MO, MT, NC, NH, NJ, NM, NV, NY, OH, OR, PA, RI, TX, VA, VT, WA, WI (Barbose 2021)
Clean Energy Standards	Requirement that a percentage of load be met with low- or zero-carbon generation (defined to include technologies beyond renewables, including nuclear and carbon capture), typically enforced by requiring distribution utilities to surrender Clean Energy Credits (representing a MWh of clean generation) equal to a percentage of their load	CA, MA, NM, NY, WA (DSIRE Insight Team 2020)
Clean Peak Standards	Requirement that a certain percentage of load in peak hours be met by clean generation occurring in peak hours, typically enforced with clean peak credits	MA (Shrader et al. 2021)
Capacity Procurement Mandates	Mandate that a certain quantity of renewable or storage capacity be procured by a certain date	Storage Targets: CA, MA, NJ, NV, NY, OR, VA (DSIRE 2022)
Cap-and-Trade Programs	Limit on emissions enforced by auctioning allowances representing tons of emissions produced by the covered entities	Regional Greenhouse Gas Initiative (RGGI: CT, DE, ME, MA, MD, NH, NJ, NY, RI, VT, VA, PA (RGGI n.d.)), CA (“Cap-and-Trade” n.d.), OR (“Climate Protection Program” n.d.), WA (“Climate Commitment Act” n.d.)

Each policy ultimately requires that investments be made in low- or zero-carbon generation. Exactly how, where, when, and by whom this occurs will affect the speed and cost of decarbonization. Many models for investing in clean generation exist, including state RPS programs (which typically require utilities to purchase renewable energy credits [RECs]) and state requirements that utilities sign Power Purchase Agreements (PPAs) with renewable generators. In addition to the mandates, many companies and utilities have pursued voluntary clean energy procurement using similar mechanisms, such as RECs, PPAs, and vertically integrated ownership of the generating resource, associated power, and RECs (NREL 2022).

Different states have handled the issue of clean energy investment differently. Some deregulated states (and a few regulated ones) require their distribution utilities (or integrated utilities) to sign PPAs with the renewable developer that wins a state RFP. For example, Massachusetts's distribution utilities signed PPAs with the developers of the Vineyard Wind offshore wind farm after state law required developing several gigawatts (GW) of offshore wind, and the state ran an auction (Gheorghiu 2018). In some other regulated states, states expect their integrated utilities to build the renewable generation themselves. For example, the Virginia Clean Economy Act (VCEA) requires Dominion Energy to petition the Virginia PUC for permission to build 16.1 GW of onshore wind and solar by 2035. The state assumed that the utility would prefer to own and operate the facilities itself, so the VCEA also includes a requirement that at least 35 percent of the generation must be procured from a third party. States also have different rules about permissible locations for renewable generation. For example, Virginia requires that 75 percent of RECs used to comply with the RPS must be from in-state generators.

Given how many state policies focus on clean generation investment, it is important to identify obstacles these policies face. The workshop discussion identified the following barriers and institutional responses to those barriers.

2.1. Market Design and Resource Adequacy Methods That Disfavor Renewables

In much of the US, generators are financed based in part on expectations about the revenue they will receive from capacity markets, which are driven by expectations of their ability to reliably meet demand and contribute to system resource adequacy. This means that assumptions about generators' ability to meet peak demand can determine which ones are built. Capacity markets often do not fully compensate renewable generators for their ability to help meet peak demand, as they are intermittent and their availability may not coincide with peak demand (Millstein et al. 2021). As a result, renewable generators have less access to the capacity payment revenue streams and may require additional financial support to drive their deployment, increasing the costs of state policies requiring renewable generation.[2]

2 One study found that changes in the estimate for a renewable generator's ability to contribute to a power system's resource adequacy can significantly affect whether those renewables are deployed (Zhou et al. 2018).

Although states that participate in regional RTO-operated capacity markets do not have direct control over those markets, they can advocate with FERC and the RTOs for a more nuanced valuation of renewable capacity. For example, PJM uses a metric called "Effective Load Carrying Capacity" (ELCC) when determining the capacity value (contribution of a plant toward meeting demand) it will assign to renewables and storage resources in its capacity market. The ELCC is a probabilistic method for determining the ability of a generator to maintain system reliability, taking into account the relationship between generation and load patterns.[3] States like California that administer the resource adequacy requirement without a capacity market by imposing bilateral payments between load-serving entities and capacity resources can also benefit from valuing both resource adequacy needs and renewables' ability to contribute to resource adequacy in a more nuanced way.

Workshop participants considered recent research on the capacity value of renewables, which indicates a need for more comprehensive methods that can fully account for the alignment between generator availability and system demand. Participants recommended research to investigate the best metrics to capture the capacity value of renewables and other resources. More broadly, resource adequacy methods may need to be updated as the grid continues to evolve: increases in intermittent renewable generation, energy storage, and more active demand participation complicate traditional approaches to determining optimal generation mixes, and extreme weather may both cause unusually high demand and compromise the reliability of some existing generation.[4] State-level policymakers can work with RTOs, utilities, regulatory agencies, and research groups to improve resource adequacy methods:

- Increase transparency around and justification for reliability criteria. Reliability and cost have an intrinsic trade-off, and policymakers can help evaluate the cost of meeting levels of reliability to determine whether it is in the public interest.
- Prioritize and provide funding for research and coordination between researchers, regulatory bodies, and system planners from around the country to share best practices.
- Incentivize the deployment of resources that can improve resource adequacy, such as dispatchable renewable energy and energy storage technologies.
- Encourage interregional coordination on reliability planning with neighboring states and power markets to ensure a more efficient use of shared resources.[5]

2.2. Backed-Up Interconnection Queues

One main factor currently limiting the deployment of renewable generation is the backup in interconnection queues. A recent Lawrence Berkley National Lab report found that the

3 For an explanation of the ELCC and other methods for evaluating renewables' ability to reliably meet demand, see Madaeni et al. (2012).

4 For example, some fossil plants were unable to operate during the Texas blizzard of 2021 (Esposito and Gimon 2021).

5 For a more detailed discussion of policymakers' roles in resource adequacy, see Redefining Resource Adequacy Task Force (2021b). For a more in-depth view of why and how resource adequacy is changing, see Redefining Resource Adequacy Task Force (2021a).

time that proposed generation projects spend in queues increased from 2.1 years for 2000–2010 to 3.7 years for 2011–2021 (Rand et al. 2022). The more time spent in the queue, the more financial uncertainty for developers and the less likely the plant will be built. The report estimates that of the 930 GW of proposed wind and solar currently in interconnection queues, only a fraction will be built. "Historically only ~23 percent of projects in queues reached commercial operations, and less for wind (20 percent) and solar (16 percent)" (US DOE Office of Policy 2022). With waiting time increasing, these proportions may shrink.

State officials seeking to resolve interconnection issues have two lines of attack, given the RTO-controlled high-voltage queues and distribution-utility-controlled low-voltage queues. States have little direct authority over RTO queues, but they can coordinate with other states in the region on transmission planning to ensure enough transmission for all the new generation. States can also engage FERC and the RTOs around interconnection backlogs, perhaps advocating for grid-enhancing technologies (GETs) to maximize the capacity of existing transmission (Caspary 2022), for prioritization of projects with the highest likelihood of being built, and for the bundling of interconnection studies. In fact, some progress on prioritization and study bundling has occurred since the workshop: at the national level, FERC's Notice of Proposed Rulemaking (NOPR) on interconnection backlogs (FERC 2022b), and, at the regional level, PJM's proposed "first-ready, first-served" process for reviewing proposed generation (Howland 2022). States have more direct authority over distribution-utility-controlled interconnection queues. PUCs can push distribution utilities to take some of the same actions states may ask RTOs to take: use GETs, prioritize projects that are easiest to connect to the existing grid, and combine interconnection studies.

2.3. Siting Opposition

Municipalities and local governments often have final say about the siting of renewable projects. This means that local opposition can have a large impact. County and municipal laws and ordinances are the largest source of impediments to renewable facility buildouts (Aidun et al. 2021). Even short of local laws forbidding development, concerted pushback against a facility can prevent its ever being built. For example, when the Massachusetts state government first pushed for offshore wind, and a developer proposed the Cape Wind project, state residents who would have had the turbines in their viewshed ended the project through unsuccessful but time-consuming lawsuits and a public relations campaign (Walton 2017).

States hoping to reduce siting opposition can coordinate with local governments and developers in advance to balance competing needs and set clear guidelines. For example, Virginia state law exempts solar facilities from some local property taxes as an incentive for developers. This has made some jurisdictions reluctant to host projects, as they will see little increase in the local tax base as a result. In 2020, a new law was passed giving localities the authority to create siting agreements with solar developers ("HB 1675 Solar Energy Facilities" 2020). These agreements are modeled on landfill siting agreements and create a public process through which localities set conditions for the development and negotiate for revenue from the project (Hopkins, n.d.). States can also help facilitate renewable development, especially community distributed energy development through conscious engagement with community-based organizations (Ramanan et al. 2021).

2.4. Policy Uncertainty

The cost of developing new generation can be heavily influenced by policy uncertainty. If a federal tax credit extension is uncertain or a state climate policy likely to be repealed, generation may not be planned or, if planned, may not be built. For example, New Jersey was one of the original states in RGGI but then withdrew and rejoined with changes in the governorship. Pennsylvania and Virginia have both recently joined the RGGI but may withdraw due to changes in political leadership (Virginia) or litigation (Pennsylvania). Joining RGGI might have incentivized building lower carbon generation, but leaving the program would reduce that incentive. Similarly, federal renewable tax credits extended through the end of 2021 under the American Rescue Plan Act of 2021 would have expired without the Inflation Reduction Act of 2022. Previous tax credit expirations have led to steep drops in renewable installations (Frazier et al. 2019).

States have no control over federal policy, but they can design their own policy with both federal and state policy uncertainty in mind by emphasizing flexible and multilayered policies. For example, in a recent report on the VCEA, researchers argued that renewable mandates maintained decarbonization progress even in scenarios where technology costs were higher than expected. However, increasing flexibility through technology-neutral generation mandates might allow for lower-cost implementation in high renewable cost scenarios (Shobe et al. 2021). In Virginia, multilayered policy also plays an important role in the face of state policy uncertainty. Although the new administration has pushed for Virginia to leave RGGI, other components of the VCEA, such as the RPS and capacity targets (5.2 GW of offshore wind, 16.7 GW of onshore wind and solar, 3.1 GW of storage) remain in place, keeping the state on a path to decarbonization, albeit at a higher cost of implementation.

2.5. Tension between Local Self-Sufficiency and Cost-Effectiveness

As states aim to decarbonize by building more renewable generation, many have explicitly pushed for it to be within state borders. For example, as mentioned, the VCEA requires 75 percent of renewables used to comply with the RPS to be in-state after 2025. The advantage of this requirement is that it may keep economic development and public health benefits in-state. States may wish to guarantee that the renewables used to meet the policy are truly additional, not ones that would have been built regardless of the existence of the program. Requiring that generation be built in-state may reduce emissions leakage if it prevents the state from relying on imported emitting electricity from outside the capped region. However, insisting that all (or a large share of) renewable goals be met in-state also raises costs, so states may need to find a balance.

Understanding the trade-offs between self-sufficiency and cost-effectiveness will require situation-specific study in different states. States can address this by asking their environment or energy agencies to do proactive planning and modeling around renewable deployment so that the PUC's response to utility-proposed plans will not be the state's only chance to influence generation decisions. States can lean more on the side of cost-effectiveness over self-sufficiency by focusing on transmission policy, as the next section will demonstrate.

2.6. Questions for Future Research

Workshop participants indicated the following as critical questions in the area of clean generation investment:

- How should renewable capacity be valued in capacity markets?
- How might states balance state-specific policies with regional cost efficiency?
- What state administrative structures are needed to facilitate coordinated action?

3. Transmission

Relying solely on in-state generation investment to decarbonize their electricity sector would be prohibitively expensive and likely insufficient to maintain power system reliability. States also need to increase transmission capacity both within their borders and beyond to cost-effectively realize their clean energy ambitions. Transmission expansion allows access to the clean generation that states want to invest in and more generally enables power flows from areas of high resource availability to areas of high demand. It reduces renewables' problem of intermittency and nondispatchability by allowing power to move back and forth between areas with less correlated renewable resources and less correlated demand profiles. Additional transmission can also help support system reliability and resilience in response to critical events. But realizing this added transmission investment requires proactive planning.

The most oft-cited example of successful transmission planning is Texas's Competitive Renewable Energy Zone (CREZ) program (Lee et al. 2017). The Texas PUC worked with wind generator and transmission developers to jointly identify areas of high resource quality and then begin building transmission to these areas before any generation existed. This approach forestalled the chicken-and-egg problem at the heart of transmission planning: developers will not build generation unless it can be connected to transmission, and transmission providers will not build transmission unless they know generation will be forthcoming. In the Texas case, once transmission to the high-resource zones existed, wind developers were happy to begin building. Because of the transmission lines, the Texas grid could use that electricity with little curtailment: it went from 17 percent at 8.9 GW of wind capacity in 2009 (prior to CREZ) to 0.5 percent at 12.5 GW of wind capacity in 2014 (after CREZ). Wholesale electricity prices in ERCOT went down because of the increased supply of zero-marginal-cost generation, falling to their lowest average in 2016 at $24.62 $/MWh ("Transmission Planning for a High Renewable Energy Future" 2017).

Unfortunately, such proactive planning is much more difficult when the lines will cross multiple jurisdictions. In fact, despite the important economies of scale to be achieved with large projects, most US transmission upgrades are occurring piecemeal without a long-term regional strategy (Pfeifenberger et al. 2021). An important exception is Midcontinent Independent System Operator (MISO) Multi-Value Projects (MVPs). The Department of Energy (DOE) National Transmission Planning Study is endeavoring to promote coordinated planning and will have many opportunities for state engagement (US DOE Office of Electricity 2022). Workshop participants identified the following barriers and state-level institutional responses for transmission planning.

3.1. Institutional Mismatch

State climate commitments are, by definition, at the state level, but cost-effective transmission planning is necessarily a regional process involving coordination among states. Typically, it is the RTOs, not the states, that lead the process. Some RTOs have engaged in comprehensive planning that includes state policy goals. For example, after extensive state engagement, MISO's MVP produced a set of projects intended to not only reduce costs and increase reliability but also help states meet their RPS targets by building transmission to high wind resource areas (MISO 2012, 2022). This type of comprehensive and integrated transmission planning is not the norm, however. RTOs all have different governance structures (Konschnik 2019) that incorporate state engagement differently, and they do not have an obligation to plan transmission around state policy goals.

States hoping to engage in the regional transmission planning process can push FERC for a bigger role in RTO planning. FERC's new Transmission NOPR includes a more formal role for states in planning (FERC 2022a), including requirements that RTOs consult states about the criteria for project selection and seek agreement from states on the cost allocation of projects once selected. States can opt out of the formal role, but if they do not, they will have to decide what project criteria and cost allocation methodologies they prefer. States can also push for more transparency and participation in RTO proceedings generally and take advantage of FERC's new Office of Public Participation (FERC 2022d) and the new Joint Federal–State Task Force on Electricity Transmission (FERC 2022c).

3.2. Cost Allocation

RTOs are supposed to follow the "beneficiary pays" principle: that is, whoever receives the benefit of transmission should pay for it, and payment should be proportional to benefits. Under the current system, RTOs often ask individual generators seeking interconnection or the ratepayers of the state where the generation will be located to pay for transmission upgrades. In reality, the benefits will extend far beyond both. PJM's interconnection studies for individual offshore wind installations identify high costs that would be assigned to each installation separately, but its 2021 Offshore Wind Transmission Planning study found that coordinating transmission upgrades to account for multiple states' commitments would benefit the entire region (PJM 2021). However, methodologies for quantifying benefits can vary widely; identifying one to determine how to allocate the costs among all the states that benefit is a challenge, and the plethora of viable approaches makes it difficult for states to reach agreement on regional transmission projects.

As mentioned, FERC's new Transmission NOPR takes the important step of giving states an official role in the cost allocation process by requiring RTOs to seek states' agreement for such plans. Some uncertainty remains about what this agreement will look like. One summary of the NOPR notes that although it requires that RTOs give states the chance to agree to the proposed cost allocation or offer an alternative, any alternative would have to be unanimously approved by all affected states and, even if such a compromise were reached, the RTO would not have to submit the state's version to FERC (Gundlach and Ladin 2022). This kind of engagement with the RTO planning process will demand substantial effort from states (see next section) and still leaves open the question of what types of benefits really matter when allocating costs according to the beneficiary pays method. Many workshop participants highlighted the need for further research on transmission benefits and their location to address this cost allocation problem. Several highlighted DOE's ongoing National Transmission Planning Study as a good opportunity to think more about benefits and cost allocation (US DOE Office of Electricity 2022).

3.3. Insufficient State Government Expertise and Capacity

Transmission planning is a complex process, and few state officials, even those serving on PUCs, have expertise in it. If states are to participate actively in regional planning, especially around areas such as project selection criteria and cost allocation, they may need to augment their staffs to develop capacity in this area. As one workshop participant noted, the new NOPR offers states the chance to engage in transmission planning, but only if they have staff knowledgeable enough in related topics to meaningfully engage in the process.

One solution to consider would be to develop offices devoted to studying transmission and engage in regional planning, perhaps under state energy or environmental agencies or even the PUC. The California Energy Commission (under the state Natural Resources Agency), for example, holds responsibility for clean energy infrastructure siting and has a special office of "Strategic Transmission Planning and Corridor Design" (CAEC 2022). This challenge is similar to the lack of internal state agency capacity in power system planning and generation deployment discussed in Section 1. State PUCs serve as adjudicatory bodies that typically react to utility plans rather than making their own. Having other state agencies, such as state energy agencies, working on both generation and transmission planning may allow states to be less reactive and more proactive in PUC and RTO proceedings. Several workshop participants once again highlighted the National Transmission Planning Study and Joint Federal–State Task Force on Electric Transmission (FERC 2022c) as places where states that engage can learn more about transmission planning and share input on their information and institutional needs.

3.4. Local Opposition to Transmission

Local opposition to new transmission lines can stall or end projects. Some incumbent generators may also oppose increased transmission if they think it will increase competition for them. The Hydro Quebec line that was supposed to pass through Maine to help Massachusetts meet its RPS targets with Canadian hydropower exemplifies both effects. Some Maine residents opposed it because of the ecological and social impacts of hydropower in Canada or because it cut through forest land in Maine, and some incumbent generators in the region opposed it for fear that the cheaper imported power would reduce the profitability of existing generation assets (Mohl 2021).

States can do little to convince incumbents who fear competition to support transmission, but they can take actions to reduce local opposition. As with generation, states can coordinate with local and municipal governments to obtain local input early to forestall substantial objections late in the process. Localities that oppose projects because they feel they are not being fairly compensated might require siting agreements like those discussed in the generation section. When local opposition stems from ecological concerns, setting clear guidelines around avoiding fragile ecosystems may help. When it stems from lack of appreciation of the importance of transmission to meeting decarbonization goals, public education campaigns may be useful. As states engage with RTOs around criteria for project selection, they can push for local willingness to be a criterion. Alternatively, state and local officials can use their greater local knowledge to help RTOs plan transmission that is least likely to raise local opposition, considering options such as undergrounding and shared rights of way and keeping in mind what areas and regions may already be overburdened with energy infrastructure.

3.5. Questions for Future Research

Workshop participants indicated the following as critical questions for transmission planning:

- How should benefits of transmission be quantified and costs be allocated?
- What input into the regional transmission planning process would states like to have?
- What levels of electricity demand should be expected in future, and what will that mean for needed transmission investment?

4. Demand Management

Although most state climate policies initially target decarbonizing the electricity sector, decarbonizing the whole economy will require electrification of other sectors, particularly buildings and transport. That means a large increase in electricity demand, and preventing peak demand from growing as fast as overall demand is one of the best ways to lower electrification costs. Lowering growth in peak demand can be done with energy efficiency and demand management (reducing overall electricity usage and moving demand for some uses strategically to avoid peak hours). Fortunately, electrification also means more opportunities for flexible load. One study by the Brattle Group shows that employing demand management techniques in a high-electrification scenario for the District of Columbia could reduce annual peak load growth from 2 to 1 percent, well within historical levels (Hledik et al. 2021).

Historically, most state policies on demand have focused on energy efficiency rather than demand management. Many states on the East Coast, for example, use RGGI funds to pay for energy efficiency programs that help households save electricity. Recently, states have begun to focus more on demand management, which has meant utility-led demand-response programs that targeted larger commercial and industrial customers through manual calls to reduce energy during peak periods. With improving technology and increased need for demand flexibility, new demand management approaches could include greater reliance on time-varying and variable retail tariff design so that consumers see prices more closely aligned with the cost of serving demand.

Although much research has focused on rate design, many options are available for facilitating demand management. Demand management could be performed voluntarily by customers responding to changing rates. But it could also be performed by incumbent utilities or new demand service providers automatically managing residential load on behalf of customers.[6] These load managers could receive compensation based on treating aggregated managed load as a type of virtual generation or reserve capacity. In jurisdictions with clean peak standards, compensation could be based on earning clean peak credits. When utilities provide demand management in lieu of building out transmission, they could be compensated based on some percentage of avoided costs.[7] However, most of these options have not yet fully materialized.

Finally, state regulators can also promote demand management by requiring utilities to consider non-wires alternatives to investments in additional generation and transmission. For example, New York's PUC requires utilities considering transmission upgrades to also consider the benefits of distributed and demand resources to help them identify a least-cost solution.

6 For more information on the potential role of utilities in providing demand management services, see Brennan (2021).

7 For a comprehensive look at possible future utility business models, see Fox-Penner (2020).

4.1. Lack of Access for Low-Income Households

Energy efficiency programs have often struggled to reach low-income households because they required spending money up front to be reimbursed later or because low-income homeowners might have other issues with their housing that limited eligibility for energy efficiency upgrades. Another barrier for low-income households is that renters often cannot take advantage of energy efficiency programs, and landlords have little incentive to do so as long as renters are responsible for energy bills (an issue often known as the “split incentive”). As states increasingly begin pursuing demand management for a larger proportion of electricity consumers, the issue of access to clean energy and demand flexibility technologies will increase as well.

Reaching low-income households with energy efficiency or demand management programs will likely require tailored programs. For example, Michigan’s utilities are asked to demonstrate energy efficiency savings that go to low-income households, and Virginia’s new Energy Efficiency Resource Standard (EERS) has a low-income carveout (ACEEE 2018). States can combine access to energy efficiency or demand management programs with programs that low-income households are used to accessing, such as the state-administered federal Low-Income Home Energy Assistance Program. States can also design programs that involve partnerships with community-based organizations. Massachusetts’ utility-run energy efficiency program (MassSave) has a partnership with the Massachusetts Community Action Program Agencies (a group of municipality-based service providers) and the Low-Income Energy Affordability Network (MassSave 2022). Finally, states can encourage utilities and other power system stakeholders to offer clean energy financing aimed specifically at low-income customers, such as Green Bank Loans or Pay-as-You-Save mechanisms (Hummel and Lachman 2018).

4.2. Inadequate Energy Efficiency Metrics

Many states have turned to energy efficiency to reduce demand. These policies are typically designed as a requirement that utilities reduce demand by a certain percentage of load each year. However, determining whether the target has been met is difficult, because demand projections are uncertain and energy savings must be measured against a counterfactual that cannot be observed. Some states handle this by compensating utilities based on investment in energy efficiency. Unfortunately, that may not be a good proxy for energy efficiency achieved, as studies have shown that the quantity promised by engineering studies is often not realized (Gillingham et al. 2018; Saunders et al. 2021). Although regulated utilities may be well placed to implement energy efficiency programs insofar as they have ready access to customers, their business model revolves around rates of return on generation and distribution infrastructure capital expenditures and revenue recovery through the volumetric sale of energy, leaving them without strong incentives to invest in energy efficiency or reduce energy consumption.

States hoping to align utility incentives with achieving energy efficiency goals can explore performance-based regulation. Performance-based regulation means that utilities only receive compensation for their energy efficiency efforts if they meet certain metrics. For example, using RGGI allowance proceeds, Massachusetts compensates utilities for a share of their spending on energy efficiency if they meet performance metrics for total demand saved, peak load reduction, and energy efficiency for low-income households (ACEEE 2018). In contrast, the Virginia EERS simply asks Dominion Energy to implement the EERS and permits it to submit an estimate of cost in its rate case without specifying how to measure whether the goal has been achieved. A UVA–RFF report recommends that Virginia consider adding performance metrics (Shobe et al. 2021). A remaining concern is how well existing evaluation, measurement, and verification techniques identify energy savings. To address the issue of measuring demand reduction against a counterfactual, an RFF study demonstrated the use of machine learning to predict demand in the absence of demand-response measures, and such approaches may provide a useful new tool for implementing performance-based regulation (Prest et al. 2021).

4.3. Inadequate Incentives for Customers

Current electricity rates do not typically reflect social marginal costs of electricity (Borenstein and Bushnell 2021). Electricity revenues must cover both fixed and variable costs. Often, the volumetric portion of the bill is designed to cover some fixed costs, which may make that charge higher than the social marginal cost of electricity and disincentivize electrification. However, relying on flat monthly charges to cover fixed costs means less incentive for reducing electricity demand and can yield high electricity bills for low-income customers who consume lower volumes of electricity. Moreover, the volumetric charge is typically fixed within a season and thus does not reflect the marginal costs of supply and how those vary throughout the day or with changes in demand and resource availability. This inflexibility means that customers do not have information about when it would be most valuable to the grid or for emissions reductions to reduce demand.

Changing electricity rates to reflect marginal costs could facilitate demand management, as customers would know when it is most beneficial to reduce demand. Many types of rates might achieve this outcome, ranging from real-time pricing (the price consumers see is linked to the wholesale price), to time of use pricing (prices vary in a predetermined way across time to reflect typical patterns of resource availability and demand), to critical peak pricing (higher prices just for a few peak hours). State PUCs have already authorized many different utility-designed rate structures (Energy Information Agency 2021). States with retail choice also have rates designed by the retail electricity provider. California PUC staff is creating a proposal for a general framework ("UNIDE," for "Unified, universal, dynamic, economic signal") for electricity pricing to facilitate demand management that may serve as a model for other states. The plan is to create a universal portal that will allow all customers to access the price, gradually introduce opt-in, real-time pricing from the wholesale market and more location-specific prices (on an opt-in basis), allow buying and selling of electricity through the portal, offer a subscription option for buying electricity (based on average load shape and energy quantity), and, ultimately, introduce the ability to lock in a price in advance based on certain usage patterns.[8]

4.4. Inadequate Incentives for Utilities and RTOs

Although demand response is theoretically a valuable resource, utility and RTO incentive structures tend to be set up to leave it at a disadvantage relative to other resources. For example, in most regulated regions, integrated utilities have an incentive to invest in generation rather than demand management, as they are guaranteed a rate of return on investments in new generation but not necessarily demand management. Similarly, in competitive regions, distribution utilities have incentives to invest in wires over demand management, as they may be guaranteed a rate of return on distribution infrastructure but not on demand management. Independent providers of demand management services have trouble entering regional energy and capacity markets. FERC Order 2222 required RTOs to allow distributed energy resources (DERs) to participate in energy and capacity markets, but it does not require them to include demand management that aggregates retail demand (FERC 2020). FERC Order 2222-A updated the rule to require RTOs to permit the participation of demand management bundled with other DERs but still exempts demand management as its own resource.

States have several pathways to address these barriers. In regulated regions, they can mandate that vertically integrated utilities consider demand management in their integrated resource plans. States might also offer compensation similar to the guaranteed rate of return on generation investment, although such programs still have the difficulty of measuring performance against an unobserved counterfactual baseline. In deregulated regions, states can ask their PUCs to mandate the use of non-wires alternatives for distribution utilities, when they are cost-effective, and offer some amount of compensation. For example, the New York Public Services Commission requires each distribution utility to create a benefit–cost handbook describing how it will quantity benefits and costs of DERs and energy efficiency; utilities must use these methodologies to be eligible for compensation. Central Hudson Gas and Electric has deferred transmission upgrades and avoided building new substations using demand response under this method (Linvill 2019). ConEd's Brooklyn Queens Demand Management Program has also enabled it to avoid a substation upgrade (Walton 2019). To address the problem of participation in regional energy and capacity markets, states can advocate with their RTOs and FERC to treat demand response as an eligible resource. However, they need to be mindful of not creating incentives to manipulate baseline electricity consumption to boost compensation for demand-response actions.

8 For a brief early look at UNIDE, consider Achintya Madduri's presentation as part of RFF (2022). For a more comprehensive look at the California PUC's thoughts on rate reform, see Madduri et al. (2022).

4.5. Inequitable and Confusing Rate Structures

In 2019 there were between 94.8 and 99.0 million smart meters (60.3–64 percent of US meters), but only 10.9 and 11.0 million customers enrolled in retail demand response or dynamic pricing programs, respectively, presumably with overlap between the categories (Burns et al. 2021). Some of the low participation relative to smart meter penetration may be due to lack of access to time-varying rates and demand-response programs, but some may be due to lack of consumer understanding or trust. Electricity rates, especially those with a time-varying component or provided by competitive retail suppliers, can be confusing. For example, one of Texas's competitive retail suppliers, Griddy, sold electricity at the wholesale price. During the Texas blackouts of 2021, customers who likely had not understood the rate structure or its risks were left with astronomical bills (Hersher 2021). Some retail choice suppliers automatically switch customers from fixed to variable rates after one-year contracts (PAPowerSwitch 2022). A report by the Massachusetts Attorney General's office found that households that purchased electricity through competitive retail suppliers paid more on average than households enrolled in the state's default utility rates and that a disproportionate number of those in competitive supply plans were minority or low income or living in majority-minority or low-income neighborhoods, providing possible evidence of targeted marketing (Baldwin 2021).

States hoping to expand new rate structures to promote demand management may want to set guidelines to prevent these kinds of confusing and harmful outcomes. Such guidlines might preclude selling real-time plans to residential consumers unless they are also enrolled in some type of automated demand management program or restrict the use of predatory practices, such as rate increases without consumer consent. Researchers emphasize the need to design customer-centric rates: rates that have been tested and focus-grouped with potential customers and are responsive to their needs (Faruqui 2021). Borenstein and colleagues (2021) suggest that if the goal is to move toward lower volumetric rates to encourage electrification, the most equitable method might be to have volumetric rates covering only variable costs and income-based fixed charges covering system fixed costs.

4.6. Questions for Future Research

The following were indicated as critical questions for demand management:

- What is the potential for demand management under different levels of electrification, different levels of smart meter uptake, and different types of rate structures?
- What rate structures provide the most value to consumers without unnecessarily exposing them to risks they do not understand?
- How much can automation increase the application of and potential benefits of demand management?
- What are the best methods for assessing the efficacy of energy efficiency programs?

5. Conclusion

The workshop on state electricity decarbonization examined some of the barriers states are encountering in their pursuit of clean generation investment, transmission, and demand management. For generation investment, these barriers include market design that disfavors renewables, backed-up interconnection queues, siting opposition, policy uncertainty, and tensions between self-sufficiency and cost-effectiveness. For transmission, these barriers include institutional mismatch between state policy and regional transmission planning authorities, difficult decisions around cost allocation for interregional transmission investment, insufficient state knowledge and capacity around transmission planning, and local opposition. For demand management, these barriers include lack of access to energy efficiency (and ultimately demand response) for low-income households; insufficient metrics for guaranteeing energy efficiency goals are met; inadequate retail price incentives for rate payers; inadequate incentives and guidelines for utilities and RTOs; and inequitable, confusing, or high-risk rate structures. These barriers can be addressed by state energy policymakers' engagement with the many partially overlapping institutions with authority over electricity—utilities, state PUCs, RTOs, FERC, the North American Electric Reliability Corporation, and municipal governments—and additional research on questions raised in the course of the workshop.

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