REBA INSTITUTE

RENEWABLE ENERGY POLICY PATHWAYS REPORT

AN ANALYSIS OF STRATEGIES TO INCREASE COMMERCIAL AND INDUSTRIAL CUSTOMER ACCESS TO RENEWABLE ENERGY

In collaboration with

THE Brattle GROUP

MAY 2020

Notice

The REBA Institute acknowledges the valuable contributions from The Brattle Group consultants on the modeling, analysis, and development of this report. We would like to specifically acknowledge the report authors Judy Chang, Sanem Sergici, Kasparas Spokas, Maria Castaner, and Peter Jones. The REBA Institute also acknowledges the contributions of the Pathways Analysis Steering Committee and the many organizations who provided feedback and input as part of the Technical Review Committee.

The REBA Institute would like to recognize staff contributions to the report, specifically Laura Vendetta and Bryn Baker. Monica Jaburg, Miranda Ballentine, Priya Barua, Jen Snook, and Camorah King also contributed to the development of the report.

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Executive Summary

Background and Purpose of the Report

The accelerating growth of renewable energy in the U.S. electricity sector over the past decade represents a pivotal transformation in the industry.[1] Commercial and industrial (C&I) demand for renewable electricity has been an important accelerant to the recent growth, with nearly 25 gigawatts (GW) of renewable energy contracted by C&I over the last decade.[2] Driven by advances in solar and wind technology that have reduced costs and increased utility procurements through both renewable mandates and voluntary demand, renewable energy now represents more than 17 percent of electricity generation in the U.S.[3] Since C&I customers collectively use over half of the electricity generated in the U.S., increased access to renewable energy resources for these customers is an important aspect of reducing emissions from the power grid.[4]

C&I customers have an increased interest in purchasing and developing new renewable energy to power their operations and facilities. These buyers include corporations, institutions, universities, hospitals, and other organizations. Furthermore, many corporations make decisions on where to site and expand operations based on where clean energy is available to them, which ultimately leads to significant economic development for states and utilities. Over the last decade, corporations have increasingly made commitments to procure renewable energy and to reduce emissions. This is evident through: (a) nearly half of the Fortune 500 companies setting climate and energy goals,[5] (b) nearly three-quarters of the Fortune 100 companies adopting sustainability

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1 This report focuses on the power sector. Renewable energy and renewable electricity are used interchangeably, and both refer only to renewable electricity.

2 Renewable Energy Deal Tracker, Renewable Energy Buyers Alliance, accessed February 14, 2020.

3 "U.S. renewable electricity generation has doubled since 2008," U.S. Energy Information Administration, March 19, 2019, accessed January 21, 2020.

4 "Annual Energy Review," U.S. Energy Information Agency, accessed January 7, 2020.

5 Power Forward 3.0: How the largest US companies are capturing business value while addressing climate change," World Wildlife Fund, April 25, 2017, accessed January 21, 2020.

and renewable energy goals,[6] (c) over 200 companies committing to 100 percent renewable energy supply,[7] and (d) nearly 1,000 companies committing to science-based targets to climate action.[8] Corporations have a powerful role in reducing greenhouse gas emissions (GHG) through their purchase choices.

Already, with their actions to support those commitments, by 2018, corporate buyers accounted for over one-fifth of all power-purchase agreements (PPAs) for renewable energy in the U.S.[9] As they continue to fulfill those commitments with increasing momentum, C&I customers want to achieve their goals in the most cost-effective manner. Additionally, many of these C&I customers prefer not to buy renewable energy credits from existing facilities because they want to drive transformation in the electricity system.

Despite strong growth of renewable development driven by corporate buyers, procurement opportunities for new renewable resources remain limited by electricity market structures and utility offerings. This is particularly true for companies that want to decarbonize faster than the requirements set by the states where the companies reside, especially where those renewable targets are already satisfied. While 13 states have set future targets for 100 percent renewable or clean energy usage,[10] the necessary approaches or the extended timeline to meet the renewable portfolio standard (RPS) targets present challenges. In light of those uncertainties, as well as C&I customers' immediate commitment to procure renewable energy, additional options and greater flexibility are needed for companies to meet their goals.

In regions without centrally organized wholesale markets operated by regional transmission operators (RTOs), customers are limited to using the incumbent utilities' offerings such as "green tariffs" to buy renewable energy. Roughly one-third of all U.S. electricity demand exists in these regions, where the incumbent utilities are the only option for C&I customers to rely on for

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6 "2016 Corporate Advance Energy Commitments," Advanced Energy Economy, December 2016, accessed January 21, 2020.

7 "Companies," RE100, accessed January 21, 2020.

8 "Companies Taking Action," Science Based Targets, accessed January 21, 2020.

9 Emma F. Merchant, "Corporate Renewables Procurement Accounted for Nearly a Quarter of All Deals in 2018," Greentech Media, February 5, 2019, accessed January 21, 2020.

10 "Progress Toward 100% Clean Energy," UCLA Luskin Center for Innovation, November 2019, accessed April 5, 2020.

renewable development and procurement.[11] The options that utilities offer to their buyers do not always respond to customer desires to advance new renewable resource development and reduce emissions. There also may be transaction costs that might deter some buyers. Often, utility offerings and programs are limited in scope due to regulatory requirements, resource planning needs, and the limited ability for utilities to provide new programs while ensuring non-subscribing customers are not negatively impacted. Addressing and overcoming the market structure barriers in regions where there are no centralized wholesale markets will be critical to enabling the continued expansion of affordable, easy-to-access, new renewable energy for C&I buyers across the U.S.

In regions with centrally organized wholesale markets, developers can build new renewable resources that connect with the wholesale power grid and sell renewable power directly to the wholesale markets. In these areas, opportunities for customers are greater but still often limited, especially for small buyers, to entering long-term PPAs with developers who bear the market risks or through utility subscription programs. In these regions, some large-scale buyers can enter into virtual power purchase agreements (VPPAs), where the buyers secure financial contracts for the renewable energy credits and/or electricity and rely on the local utilities to pass their VPPAs' costs through the retail electricity services. While these VPPAs provide greater options and flexibility for large energy buyers to procure renewable energy and have driven much of the growth in corporate renewable procurement, VPPAs are limiting for most customers that do not have the internal resources or scale to broker such financial contracts.

In addition to differing market structures, the policies that impact the development of new renewable energy are fragmented and inconsistent across the country. Each state's energy market structure and local policies dictate utilities' ability to create new programs, and state regulatory bodies have varying degrees of limitations in approving new tariffs and programs. The heterogeneity in the market structures and regulatory regimes prevent a straightforward and uniform pathway to improve access to renewable energy procurement across the whole country.

The Renewable Energy Buyers Alliance (REBA) Institute, in consultation with The Brattle Group, commissioned the Renewable Energy Policy Pathways Report to identify and evaluate the potential pathways that increase access and decrease costs of renewable energy resource

11 "Energy Primer: A Handbook of Energy Market Basics," Federal Energy Regulatory Commission, 2015.

procurement by C&I customers across the U.S. This report is intended to identify energy policies and market structure reforms that are cost-effective, customer-driven, and expedient to unlock the marketplace for C&I customers to access the renewable electricity needed to drive rapid decarbonization of the power sector.

This report is intended to inform policymakers, regulators, and other stakeholders of the potential pathways to increased access to renewable energy, characterizes the cost implications of these pathways and establishes near- and long-term strategies to improve access in the eight sample states analyzed.

<u>The specific objectives of this report were to:</u>

1. Analyze the various policies and market designs that either enable or impede renewable energy procurement for C&I customers in the eight sample states that span different market structures and regions across the U.S.;
2. Offer high-level policy and regulatory solutions ("pathways"), both short and long-term through 2030, to mitigate renewable procurement barriers and develop policy reform strategies that could expand corporate renewable procurement;
3. Develop an analytical framework and evaluate the impacts of pathways for the eight sample states.

This report begins by providing a brief background of the factors that impact renewable energy development in the U.S., which includes the organization of markets; the regulatory policies governing utility programs; the effect of geography on renewable cost-effectiveness; and other factors. Next, we identify and evaluate the potential of policy pathways for eight sample states. These states are Arizona, California, Colorado, Georgia, Massachusetts, Minnesota, North Carolina, and Virginia. Additional details are provided in the appendices, including details about electricity market structures, available options for large-scale buyers to procure renewable energy, and discussion about policy pathways.

Analytical Framework

The analysis contained in this report identifies potential policy pathways to help improve C&I customers' access to renewable electricity and contributions to decarbonizing the electricity system. The study analyzes three major policy pathways:

1. **Advance state policies (i.e. renewable portfolio standards) that would expand mandated renewable energy purchases for jurisdictions**, either for an entire utility service territory or for an entire state.
2. **Expand utility subscription programs for renewable energy** to enable C&I customers to procure renewables through their local utilities.
3. **Introduce supply choice** (and by default, implement centrally organized wholesale markets for currently non-wholesale market states) to increase participation of wholesale and retail suppliers developing renewable energy services for all customers.

To evaluate these three policy pathways, eight sample states were selected to represent a diverse combination of existing regulatory structures, centrally organized wholesale markets, renewable energy resource potential, and existing power generation portfolios that span the range of features found in the U.S. The sample states span from Massachusetts, which is in a centrally organized wholesale market(ISO-New England), has an aggressive statewide renewable energy goal, and has implemented full retail choice; to Georgia, which is not in a centrally organized wholesale market, has no statewide renewable energy goals, and has limited consumer supply choice. To ensure adequate diverse regional representation, the sample includes states from the West Coast, Midwest, South, Northeast, Mid-Atlantic, and the Southwest.

For each state, the *potential impact* of each policy pathway's ability to improve C&I customer access to renewable energy is assessed based on ***three impact metrics:***

i) ***Percent of C&I customer demand with access to 100 percent renewable energy supply*** in 2030;

ii) ***Potential amount of renewable energy capacity (GW) that could be deployed*** to meet that demand under each policy pathway; and

iii) ***Potential procurement costs (cents/kWh)*** associated with deployment of each pathway.[12]

To determine whether there is an opportunity to build more renewable energy resources ("headroom capacity") without exacerbating any stranded asset issues, we estimated the amount of renewable energy resources that could replace at least a portion of the fossil fuel generation capacity that is naturally expected to retire before 2030. The expected fossil power plant retirements present opportunities to increase renewable energy deployment without creating incremental stranded assets.

Key Takeaways

Despite having a large potential for increased build out of renewable capacity in many states, the actual amount of renewable energy built by 2030 to meet C&I customers' procurement demand at low costs will highly depend on (a) ***the starting point of each state*** in terms of the regulatory and market structure, (b) ***the choices that the states make*** in terms of participating in a centrally organized wholesale market and allowing customers to choose their supply resource types, (c) ***the renewable resources available*** in the vicinity of the states, (d) ***the cost*** of those renewable energy resources, and (e) ***the amount of headroom capacity*** created by retiring fossil generation.

In analyzing these factors across the eight sample states, we find that:

1. **Allowing customers to choose their suppliers (such as in states with retail choice) has the highest *technical potential* for expanding access to the most C&I customers (potentially up to 100 percent) and lowering the cost of renewable energy procurement up to 11 percent compared to if customers cannot choose their suppliers.**

    - For the eight sample states analyzed, introducing supply choice to C&I customers could result in demand for roughly **50-150 GW** of new renewable capacity above the *status quo*, depending on customer adoption.

[12] Costs of renewable procurement are calculated as a summation of energy, transmission, distribution, renewable procurement premiums (where applicable) based on historical prices, and stranded cost charges (where applicable) based on forecasts of renewable costs and utility renewable programs. For details, see Section III.

- However, uncertainties remain about the cost of offerings (Table 1) and the resulting impact on customer adoption, especially given states that currently have full retail choice have not yet led to significant reductions in customer renewable procurement costs.

- Cost and adoption uncertainties are especially true for the introduction of retail competition in sample states without wholesale markets, where potential stranded assets costs are highest and could lead to cost increases up to 15 percent in the near-term. The stranded costs of introducing greater choice are likely higher in states currently without centrally organized wholesale markets.

- While not directly analyzed quantitatively in this study, participation in centrally organized wholesale markets, regardless of supply choice status, is key to increase customer options, reduce costs, and facilitate greater renewable energy integration as evidenced in past studies (see additional explanation below).

2. **Utility subscription programs in states where C&I customers cannot choose their suppliers, provide attractive near-term opportunities to improve C&I customer access to renewables.**

    - Scaling these programs to the equivalent capacity of natural fossil retirements could prevent stranded costs.

    - These programs have the potential to deploy up to 52 GW of renewable energy across the eight sample states at modest cost savings relative to status quo (up to five percent), with the most potential in the sample states without a centrally organized wholesale market.

    - Technically, utilities have the potential to offer similar amounts of renewable access as retail providers in retail choice states. However, such behaviors will only be pursued by utilities if they do not face punitive financial consequences from early plant retirements.

3. <u>Moderate RPS expansions beyond the *status quo* by 2030</u> have the potential to "green the grid" for all customers, but do not provide direct customer procurement options or C&I customers' ability to go beyond state renewable targets.

- Across the sample states (excluding California as it already has one of the most ambitious RPS policies), moderate RPS expansion has minimal cost implications and provides up to 28 GW above the status quo by 2030.

- The strength of an RPS expansion will depend on whether it guarantees new renewable energy deployment and can move the burden of procurement from buyers, who may have limited resources to undergo bilateral contracting, to utilities and/or states.

Table 1
Summary Results for Policy Pathways Grouped by State Market Structure

Policy Pathway	Technical Potential of New RE Capacity Relative to Status Quo (GW)	Technical Potential of C&I with RE Supply (% of Demand)	Potential Cost Ranges Relative to Status Quo (% Change)
States without Centrally Organized Wholesale Markets (AZ, CO, GA, NC) (Status Quo in 2030: 5 GW of New RE for all)			
Moderate RPS Expansion Above Status Quo (SQ)	up to 19 GW	up to 33%	-3% to 0%
Utility Subscription Expansion	up to 46 GW	up to 60%	-5% to +1%
Supply Choice Introduction	29 to 92 GW	43% to 100%	-11% to -1%
States with Centrally Organized Wholesale Markets (CA, MN, VA) (Status Quo in 2030: 20 GW of New RE for all)			
Moderate RPS Expansion (only MN and VA) Above SQ	up to 6 GW	up to 46%	-1% to +1%
Utility Subscription Expansion (only CA and MN)	up to 6 GW	up to 63%	0% to +2%
Supply Choice Introduction	19 to 45 GW	66% to 100%	-5% to -1%
States with Retail Choice (MA*) (Status Quo in 2030: 7 GW of New RE)			
Moderate RPS Expansion Above SQ	up to 3 GW	up to 59%	-0.3% to +1%
Retail Choice Enhancement (stranded costs N/A)	6 to 14 GW	61% to 100%	-12% to -11%

Notes: Capacity additions reflect upper bound on potential. For the Supply Choice Adoption Pathway, the lower bound reflects the capacity for historical adoption (32 percent). The upper bound reflects 100% adoption. Cost ranges reflect the change in cost in each state averaged over the states in each market structure, weighted by the increase in renewable energy in each state by the pathway. There remains uncertainty regarding future renewable costs and renewable procurement premiums. Stranded asset costs were also modeled for a full supply choice scenario and can be found in the state profiles. For the Supply Choice Adoption Pathway, the energy component of costs is priced at only the levelized RE cost in each state, and the full cost range includes uncertainty regarding stranded cost treatment (where applicable for supply choice scenarios). *It is assumed that 30% of current retail customers in MA are subscribed to RE-only retail products for the RPS Expansion pathway, and 50% for the Supply Choice Expansion pathway.

Summary of Findings

1. **Introducing supply choice to C&I customers, has the highest technical potential for expanding access to the most C&I customers (potentially up to 100 percent) and lowering the cost of renewable energy procurement.**

   - **Customer Access to RE (percent C&I Customers).** Introducing supply choice for C&I customers can *potentially* expand access for renewable products to **all customers**. If renewable energy services can become a more cost-effective option than non-renewable options, then the number of customers switching to renewable services may increase well beyond the historical benchmark of 32 percent adoption. The existence of flexible, cost-competitive options for renewable energy also increases prospects for attracting state economic development benefits, given the number of business predicating business expansion on access to renewable energy. However, there are significant uncertainties around the likely success of introducing supply choice to C&I customers, including retail suppliers' ability to procure new renewable capacity at low costs and the treatment of stranded assets. Addressing these uncertainties will require significant additional analyses.

   - **RE Capacity (GW).** Using historical customer switching rates for all retail electricity services results in demand for over **50 GW (up to 150 GW)** of additional renewable development relative to the status quo over the eight sample states analyzed in 2030, (Table 1) roughly twice the renewable development under status quo. However, adoption rates for retail electricity services are a key uncertainty.

   - **Costs ($).** Stranded asset recovery costs may limit the near-term benefits of introducing supply choice for C&I customers, potentially increasing costs up to 15 percent. Once stranded asset costs are paid off, the renewable procurement cost could be **five to 11 percent lower** than the status quo if suppliers price electricity near the costs of new renewable development. Therefore, supply choice has the greatest potential cost savings of the pathways analyzed. In our analysis of the eight sample states, moving to full supply choice in states that already have an underlying centrally organized wholesale market resulted in lower potential stranded costs.

While not directly analyzed quantitatively in this study, participation in centrally organized wholesale markets is key to increase customer options, reduce costs, and facilitate greater renewable energy integration, as evidenced in past studies.[13, 14, 15] Participation in centrally organized wholesale markets likely makes any of the examined policy pathways cheaper by providing a broader market for renewable energy, encouraging utilities and merchant generators to invest in expanded renewable generation capacity, and enabling market forces that both lower the cost of energy and edge out expensive, nonrenewable generation sources like coal plants. Encouraging centrally organized wholesale market participation where they do not yet exist will provide significant additional benefits to each jurisdiction, such as:

- **Greater customer access to options.** Buyers in these markets have the ability to sign VPPAs directly with developers for new renewables that participate in local markets, providing better energy price correlation to their actual energy costs. Utilities in these markets have more opportunities to provide buyers a variety of tariff structures than in regions without a centrally organized wholesale market, such as market-based rate tariffs that can facilitate buyers to procure VPPAs.

- **Greater RE integration.** Utilities operating in centrally organized wholesale markets can lean on the larger system for integrating and balancing a system with diverse renewable energy resources to meet reliability standards and reducing the cost of renewable integration, which in turn reduces the costs to all customers.

- **Costs ($).** Existing centrally organized wholesale markets provide billions in documented customer savings annually by operating markets efficiently using their scale and diversity of assets, pooled dispatch, marginal cost pricing, and coordinated transmission planning.

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13 "2018 MISO Value Proposition," Midcontinent ISO, February 2019, accessed January 21, 2020.

14 "PJM Value Proposition," PJM Interconnection, 2019, accessed January 21, 2020.

15 Sanem Sergici, "The Status of Restructuring: Whole and Retail Markets," presented to the National Conference of State Legislatures, June 26, 2019.

- **In states already participating in centrally organized wholesale markets and retail choice (e.g. MA), retail products and switching terms could be improved to help expand renewable-based retail options for all customers.**

  - Innovative renewable energy products, such as renewable output volume firming agreements or digital renewable energy credit (REC) providers, can help customers procure renewable energy readily to meet their needs.

  - Third-party retailers will need to provide programs that support new renewable development, bear some of the risk of long-term renewable contracts with developers (unless state policies allow retailers to pass on those risks to the local distribution utilities like what Massachusetts has done), and provide customers transparent information about their procurement.

  - As evidenced in the current markets with retail access, the development of these programs should not be taken for granted as they require much work and coordination between retail suppliers, buyers, and regulators.

  - Despite substantial long-term benefits of centrally organized wholesale markets, building consensus with the necessary stakeholders to support organized wholesale markets participation can be challenging.[16]

2. **Utility subscription programs in states without supply choice provides attractive near-term opportunities to improve C&I customer access to renewables.**

   - **Customer Access to RE (percent C&I Customers).** Expanding utility subscription programs provides near-term opportunities to expand customer access up to **60-63 percent.** Additionally, utilities participating in centrally organized wholesale markets can provide options for buyers to hedge energy prices with renewable procurements, such as market-based tariff rates.

[16] Additional benefits and challenges of introducing a centrally organized wholesale market are discussed in Appendix C.

- **RE Capacity (GW).** During our study time period (2020-2030), the utility subscription programs have the potential to expand renewable development by **52 GW** relative to the status quo in 2030 (Table 1) – r oughly twice the capacity installed in the states today. Utilities will need to ensure that the retiring generation capacity is replaced by renewable facilities, and that they are made available for subscription programs.

- **Costs ($).** Renewable energy procurement costs for C&I customers through utility programs often include various administrative charges or premiums above retail rates that do not reflect the costs and savings from new renewable development, such as premiums for renewable credits from existing renewables rather than the net system costs of new renewable development. In our analysis, costs range from **slight cost increases to a five percent savings**. Utilities and regulators should consider competitive procurement to drive down the cost of renewable supply and apply subscription program cost structures that reflect the net system costs and benefits.

- Expanding utility subscription programs may be considered the most effective near-term renewable access pathway to go beyond an RPS because engaging utilities may have a higher likelihood of success than moving markets to full supply choice. Uncertainty around cost premiums and consequent adoption rates for these programs, may present challenges to achieving the full technical potential of this pathway.

  - For states in our sample that are not in a centrally organized wholesale market (AZ, CO, NC, GA), high levels of old, existing fossil generation, which are due to be retired in the coming years, provide utilities the opportunity to develop renewables and create utility renewable subscription programs with no stranded costs.

  - For states already participating in centrally organized wholesale markets but do not have full supply choice (CA, MN, VA), the potential to deploy new renewable energy resources is limited by the relative economics of renewable resources compared to other resources (especially when considering intermittency), utility long-term plans, stranded asset considerations, transmission capacity, and system planning.

- The opportunity to increase utility offerings could be increased even further, if more than the currently planned retirements were replaced by renewables. Technically, utilities have the potential to offer similar amounts of renewable development as do retail providers. However, such behaviors will not be supported by utilities if they face punitive financial consequences from identifying and pursuing savings in their resources from early retirements. Those displaced assets will have to be immunized from stranded cost losses.

3. **In all states, moderate expansion of RPS programs directly "green the grid" for all customers, but do not necessarily increase direct C&I customer procurement options or create opportunities for buyers to go beyond state renewable targets.**

   – **Customer Access to RE (percent C&I Customers).** RPSs mandate increased renewable energy deployment and can move the burden of procurement from C&I customers, who may have limited resources to undergo bilateral contracting, to utilities and/or states. This serves as an effective tool to increase renewable energy **delivery to all customers** but how much renewable energy is provided depends on the ambition of the RPS. In this study, the percent of total C&I demand (in MW, not number of customers) would be served with renewable energy by RPS ranges significantly from 33 percent in states without a centrally organized wholesale market, to 46-59 percent in a centrally organized wholesale market and retail choice states. Importantly, an RPS alone also does not provide a direct mechanism for C&I customers to go beyond RPS goals to procure renewable energy for their own needs.[17] More specifically:

     - In states with a high RPS (CA and MA), new renewable resources to be deployed by utilities or retailers will likely be used to meet their respective shares of the current RPS.

17 The Virginia Clean Economy Act in Virginia does create limited pathways for certain "accelerated renewable energy buyers" to contract directly for RPS-eligible renewable resources and potentially go beyond the RPS. This is a model that could be expanded in other states.

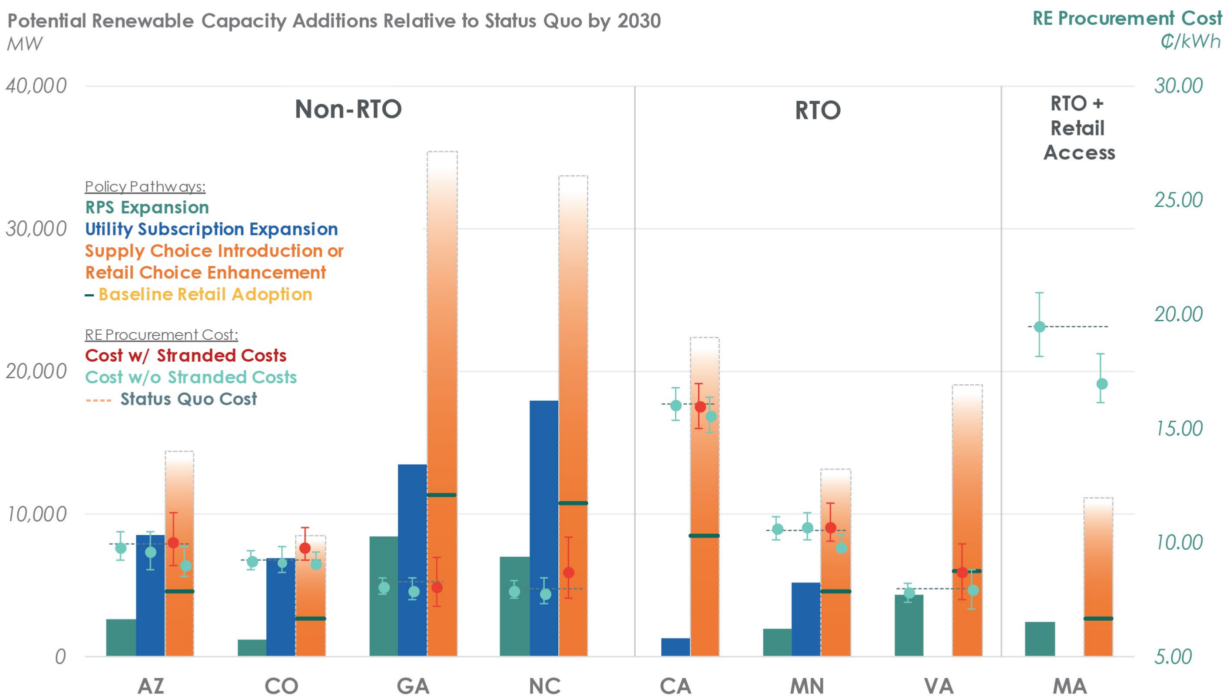
- For states with lower RPS (AZ, NC, GA), there is less need for new renewable capacity without retiring existing fossil capacity, and renewables are spread across the entire customer base, so a proportionately smaller amount is going to C&I customers. In these states, the retirement of old, inefficient fossil generation presents the opportunity to deploy renewable energy resources to replace the energy needs of the state beyond the amount needed to meet the RPS, which could be made available to corporate customers through utility subscription programs.

– **RE Capacity (GW).** The degree by which RPS policies can help quickly deploy significant amounts of renewable energy depends on their ambition. Many C&I buyers have set significant goals (e.g. up to 100 percent renewable energy in the next five to 10 years), which would not be met through an RPS alone. The aggregate results show that moderate increases in currently set RPSs from the eight sample states analyzed generally do not offer as much technical potential (**up to 28 GW** in aggregate) as the utility subscription or supply choice pathways (Table 1). However, an expanded RPS can provide a more secure outcome, whereas the other two pathways would depend on many indeterminate factors to come to fruition. It is important to note that ambitious (more than 50 percent) increases in RPS by 2030 were not studied explicitly in this report.

– **Costs ($).** Expanding RPSs moderately in the eight sample states has limited cost impacts (**ranges -3 to +1 percent** across market structures) relative to the status quo, largely due to increasing the amount of cost-competitive renewable energy generation on the grid.

The most effective policy pathway (taking into account both the deployment potential and the cost) to advance the C&I customer renewable energy procurement varies by state as a result of different starting points in terms of the existing market and regulatory structures, the current portfolio of generation assets, utilities' willingness to support the interests of C&I customers, and the treatment of any potential stranded asset costs (Figure 1).

Figure 1
Potential Capacity Additions Relative to the Status Quo by Policy Pathway and Estimated Procurement Cost



Note: Range in costs reflects uncertainty of future renewable energy levelized costs and customer procurement premiums, with the mid-point representing average forecasts. For the Supply Choice Adoption pathway, a range of stranded costs are added to the procurement costs. The horizontal line for the Supply Choice pathway indicates the 32% historical adoption rate, indicating additional customer adoption beyond the historical adoption rate is possible. Stranded costs are assumed to be spread over the whole rate base (details in Section III). RPS Expansion for CA is not modeled due to their already established high renewable mandates. Utility Subscription Expansion is not modeled for VA due to their need to replace most headroom capacity with renewables to meet their current RPS.

Other Policy Considerations

Decarbonizing the U.S. electric sector is imperative to mitigate the effects of global climate change. Increased access to renewable energy resources for C&I customers is an important component of decarbonization because it is a driver for replacing emitting generations with emission-free renewables to clean up the power grid. One of the more comprehensive policy pathways, not analyzed in this report, to decarbonize the electric sector is to institute a firm national commitment to decarbonization through carbon pricing or setting carbon emissions limits. Having a national policy around carbon emissions would provide the most cost-effective platform for all electricity users on average to purchase renewable energy by taking advantage of the lowest-cost opportunities across the country, rather than limiting opportunities to specific states.[18] Though historically, implementing such policies have had many barriers.

National policies in support of renewable development will provide grid operators visibility necessary to adequately plan for future system needs and societal transitions. Moreover, centrally organized wholesale markets have a large role to play in facilitating the access and cost opportunities identified in this report and can assist in ensuring that reliability of the system is maintained as the transition to renewables occurs. While these more ambitious initiatives are gaining momentum, utilities, policymakers, regulators, and other stakeholders should continue to work on the pathways identified in this study to make progress towards a future with improved access to renewable energy.

Conclusion

Despite varying strategies and levels of opportunity by state, one thing is clear: there is *great potential* to improve the richness of opportunities for C&I customers' procurement of new renewables in the U.S., both near-term and long-term. While our analysis covers eight sample states, there is a great deal of commonality in the results within market types; therefore, the high-level conclusions are largely transferable to other states even if regional opportunities still need to be tailored to local conditions. Potential exists to increase the renewable access options available to customers through both utility offerings as well as centrally organized wholesale markets and competitive retail markets. Utilities that anticipate replacing old fossil generation over the next decade hold the key to unlock much of that potential. Utilities, state utility regulators, C&I customers, and other stakeholders have an important opportunity to collaborate and ensure that replacement capacity is clean while expanding C&I customer programs with cost-effective tariff structures. While broader introduction of centrally organized wholesale and competitive retail markets does have a great potential to lower cost and increase access over the long-term, more work needs to be done state-by-state to properly analyze political will for changes to market structures, its potential to improve renewable access to C&I customers at low costs, and especially its implications for potential stranded costs.

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18 Fowlie, et al. "An economic perspective on the EPA's Clean Power Plan." 2014. Science, 346(6211), pg. 815-816.

I. Existing Renewable Energy Procurement Options

Corporate access for renewable energy procurement depends on a variety of factors, many of which are not under the buyers' direct control. Some of these are the result of the regulatory and policy landscape, such as access to centrally organized wholesale markets and renewable energy policies, or lack thereof, that affect the overall set of options for procurement. These factors also impact system planning and cost recovery processes, which ultimately dictate renewable development and costs of renewables in a state. In addition, there are geographical factors, such as sunlight coverage and wind speeds that impact renewable energy costs. The following factors were considered when developing the framework and analytical approach for the report:

- **Various Market Structures** (vertically-integrated utility structures, centrally organized wholesale markets without supply choice and states that have implemented retail choice)
- **Utility System Planning and Cost Recovery** (treatment of stranded assets)
- **State-level Renewable Energy Policies and Utility Decarbonization Commitments**
- **Local Geography and Renewable Resources**

The factors impacting renewable energy access are explored in greater depth in Appendix A.

Customer options for renewable energy exist for every market structure (Table 2); however, availability of options can be limited by the market structure in the state. For instance, wholesale contracts, such as PPAs, have been tremendously popular among large-scale buyers, but are limited to states with centrally organized wholesale markets. Yet, utilities can provide similar options through utility sleeved-contracts in vertically-integrated states. The details of each option and the various factors impacting C&I procurement options are reviewed in detail in Appendix B.

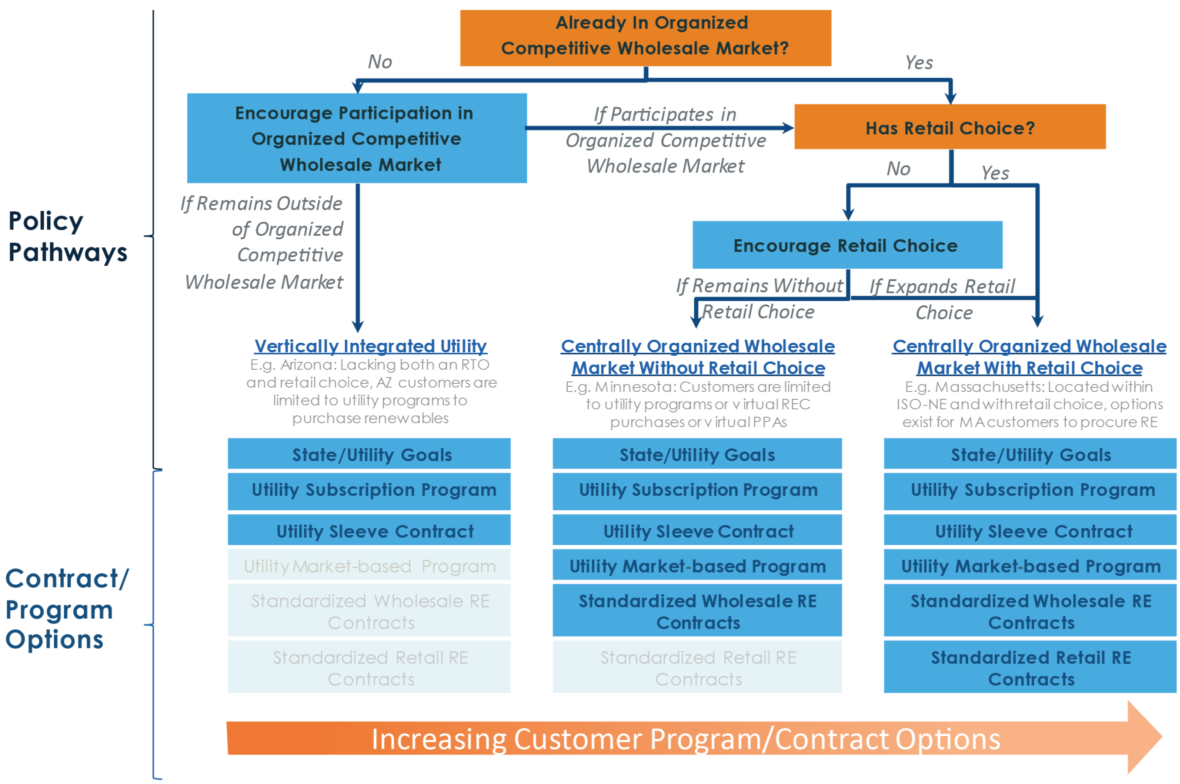
Table 2
Renewable Energy Access Options

Access Option	RE Buyer and Customer Relationship	Price Risk	Common Barriers	Market Structure Needed
State and Utility Goals/Mandates	• Typically, the utility is the counter party (buyer) that procures RE from developers • Customer receive a share of RE through regular utility service	• Short-term price risks are relatively low, as utilities will provide fixed electricity rates. • Long-term prices are dependent on future utility procurements.	Alone, state and utility goals lack customer empowerment/choice	None
Utility Subscription Program	• Typically, the utility is the counter party (buyer) that procures RE, planned via IRP. • Customers subscribe to RE through a utility program.	• Price risks depends on the program rate. • Fixed rates provides certainty while variable rates do not.	Often, programs are limited in total MW (or MWh) available and have costly premiums and other inhibitive fees.	
Utility Sleeve Contract	• The utility is the counterparty (buyer) to renewable owner and "sleeves" RE through to customer.	• Price risks can be low as sleeve contracts provide fixed charges.	High effort and knowledge needed which excludes smaller buyers.	
Utility Market-rate based Program	• Utility buys renewable wholesale energy at market-based prices and customers buy at same price.	• Variable market prices cause price risks for customers, unless paired with a PPA.	Buyers are exposed to centrally organized wholesale market electricity price uncertainties, unless paired with a PPA.	Centrally organized wholesale market
Standardized Wholesale RE Contracts*	• The customer is the counterparty (buyer) of a PPA from developer.	• Low price risk as the PPA provides an energy price hedge in the local market.	High effort and knowledge requirements mean that it may not scale easily. Though third-party PPAs exist and can ease procurement effort.	
Standardized Retail RE Contracts	• A retail supplier is the counterparty (buyer) of PPA or procures RECs through markets and sells aggregated RECs to the customer.	• Price risks depend on the contract rate. • Fixed rates provide certainty while variable rates do not.	If not designed properly, contracts may lack transparency or standardization, resulting in buyers being unsure of the best offering.	With supply choice and organized wholesale market

II. Policy Pathways

Policy pathways are strategic approaches that could be used to expand renewable energy procurement for commercial and industrial (C&I) customers. As discussed in previous sections, barriers to procuring renewable energy vary state-by-state, primarily determined by the electricity market structure. The policy pathway taken by a state impacts the renewable energy procurement options available to customers (outlined in Section I), especially if it alters the market structure of the state. Introducing a centrally organized wholesale market introduces the most options by allowing developers to access transmission and allows PPAs and procurement options derived from underlying PPAs. Figure 2 presents a flow diagram that illustrates the procurement options that arise from alternative policy pathways.

Figure 2
Policy Pathways Impact on Renewable Energy Procurement Options Available



Notes: Some states without centrally organized wholesale markets organized by Regional Transmission Operators might allow for third-party PPAs, but such deals are often not standardized and require engagement of the utility to provide such an offering.

The policy pathways analyzed in this study encompass a collection of strategies aimed to address many market structures with varying degrees of reform, ranging from providing more renewable procurement options through subscription programs to major structural changes to the electricity market (Table 3). Ultimately, each is aimed at addressing current barriers limiting the ability of C&I customers to procure renewables. These include:

- **Insufficient Supply of Renewable Energy:** In some states, limited renewable energy is available for contracting for C&I customers. This is most likely in states without centrally organized wholesale markets, where the incumbent utility controls much of the development of new resources and may not develop much, if any, new renewables.

- **Limited Access to Renewable Energy:** Even if renewables are developing, its availability for customers may also be limited by the utility. This includes capping the amount of renewables eligible for subscription programs or categorizing renewables for certain retail classes or customers, effectively limiting their availability.

- **Difficulty of Procuring Available Renewables:** While renewable energy development might not be limited by market structures, such as in states with centrally organized wholesale markets, the ease of which a customer can procure these resources varies. Absent a subscription program, bilateral contracts, which require a large amount of effort and knowledge to procure, might be the only option available. This could effectively limit the opportunities to large-scale buyers.

- **Cost of Renewable Procurement:** Lastly, the structure of renewable energy procurement options can impact the cost of the procurement. Subscriptions with high premiums, high upfront administrative costs, and long contract lengths in states where the underlying renewable energy might be relatively cost-effective, limits the customers who can participate in such a program, especially small-scale buyers.

Table 3
Policy Pathways and Their Applicable Market Structure

Policy Pathways
1) **Advancing state policies (i.e. renewable portfolio standards) that would expand mandated renewable energy purchases for jurisdictions,** either for an entire utility service territory or for an entire state. This will increase the grid average renewable electricity delivery to the customer.
2) **Creating or expanding utility subscription programs** allow customers to subscribe to a portion of the electricity of a renewable project through a utility tariff. In these programs, the utility is the counterparty (buyer) of the renewable generation through a power purchasing agreement (PPA), and the customer subscribes to a portion of the PPA. This pathway was not modeled for states with existing access to retail choice (MA).
3) **Introducing supply choice** (and by default centrally organized wholesale markets for currently non-wholesale market states) allows customers to engage with retail suppliers and wholesale electricity providers using a standardized tariff rate, which can increase the renewable energy procurement options and retail competition.
Additional Policies to Consider (Not analyzed in this report): • **Forward Clean Energy Market** allows customers to purchase renewable and clean attributes in a centralized forward market that aggregates demand and supply.[19] • **Carbon Pricing** introduces a price on GHG, which shifts the economics of energy generation away from emission emitting resources towards renewable energy resources. • **Federal Clean Energy Standard** mandates a level of renewable development across the country, but allows for geographical differences in renewable quality to influence where renewable development occurs

In Appendix C, we discuss the details of the policy pathways that are used in the subsequent analysis of policy reforms relevant for the selected states, which are (1) creating or expanding state policies that would mandate additional renewables for its jurisdictions, such as RPSs, (2) creating or expanding utility subscription programs, and (3) introducing supply choice for C&I customers (and by default, centrally organized wholesale markets for currently non-wholesale market states). Additional policy reform pathways are also discussed for completeness but will not be featured in the subsequent analysis. For the purpose of this report, under the Supply Choice pathway, we use the term "supply choice" to represent the desire for C&I customers to be able to choose their supply resources. We recognize that a full implementation of retail choice would involve significant and important political processes in every state, which is not addressed in this report. Thus, while we intend to analyze the potential impact of allowing C&I customers the ability to procure renewable

[19] Kathleen Spees, Samuel A. Newell, Walter Graf, and Emily Shorin, "How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals," The Brattle Group for NRG, September 2019.

energy as they desire (including a simple estimate of the potential range of stranded costs), we do not analyze the full suite of issues associated with retail choice, such as detailed estimate and specific treatment of stranded costs; the identity and arrangement of the providers of last resort; the pricing of default services; and the competitiveness of the retail businesses in this report. To emphasize that we have not comprehensively analyzed the potential impact of introducing retail choice in states that do not have it, we use the term Supply Choice for C&I Customers to represent only the narrow component of allowing C&I customers to choose from a specific portfolio of supply resources.

III. Policy Pathways Analysis Methods

To evaluate various pathways to increase renewable energy access for C&I customers in the eight sample states, a framework was developed to evaluate the potential of each pathway. This framework includes selecting three pathways that represent different approaches to achieve the goal of increased access and evaluating these pathways according to several metrics. The analytical framework allows policymakers to identify the *technically achievable potential* to develop renewables for C&I customers under each pathway according to each states' structural opportunities. The choice to evaluate *technically achievable potential*, rather than forecasting *adoption*, allows for the identification of opportunities without the inherent uncertainty of modeling adoption for which very little data exists. Potential development of renewables and costs in our analysis allows for policymakers to weigh tradeoffs between pathways, and ultimately provides a "menu" of options that policymakers can evaluate when deciding on near- and long-term strategies to increase renewable access.

The three pathways that are evaluated are (1) advancing state policies that would mandate additional renewables for its jurisdictions (i.e. state RPS), (2) expanding utility subscription programs, and (3) allowing for supply choice for C&I customers. In the utility subscription expansion pathway, we estimate the potential for utilities based on assumed future retirements to expand their offerings without incurring stranded costs. But for select states where assumed retiring fossil generation did not present opportunities to expand utility programs, a second utility subscription expansion pathway named "Utility Subscription Expansion 2" was developed to expand offerings and spread the stranded costs only on the C&I customers. Table 4 provides an overview of the assumptions and questions being answered under each pathway. The introduction of centrally organized wholesale markets, carbon pricing, or federal climate policies are not examined to focus on state-level opportunities that are irrespective of nationwide policies, which might be subject to much policy uncertainty in the near future. In addition, we do not model expansion of RPS beyond 50 percent, as an accurate representation of such high renewable penetration scenarios would require modeling beyond the scope of this study. For the purposes of this report, we assume the load buys renewable resources in its respective state, and do not model the transition or estimate costs of a centrally organized wholesale market introduction beyond estimating a range of stranded asset costs. However, introducing supply choice for states without a centrally organized wholesale market does implicitly assume introduction of a centrally organized wholesale market. In addition, adoption of retail products is not modeled due to data unavailability. Historical adoption rates are used, but competitive renewable products could result in much higher adoption. Pathways are evaluated for 2030, a timeframe that allows for both near- and long-term strategies.

Table 4
Pathways Analyzed in Quantitative Analysis

Pathways Analyzed	Assumptions	Questions being answered
Status Quo	• Currently announced RPS is met • Utility subscription programs remain unchanged	• How much renewable energy development is expected given policies and programs already developed?
Utility Subscription Expansion	• Utility subscription programs are expanded with renewable development • RE amount for program expansion estimated using likely fossil fuel retirement (by age) beyond the new RE needed for current RPS	• How much potential retiring generation could the utility replace with renewable energy that would be eligible to incorporate into a C&I subscription program?
RPS Expansion	• RPS is expanded • Utility subscription programs remain unchanged	• How much renewable energy development could a realistic RPS expansion yield?
Provide Supply Options for C&I Customers	• Supply choice is introduced for C&I customers • Average historical adoption of retail choice assumed, based on U.S. retail adoption data • RE supply provided by new renewables • Assumes perfect procurement of RE to meet customer load (no storage or backup generation costs) • Stranded assets are considered	• If renewable energy adoption rate is similar to historical retail choice adoption rate, how much renewable development could we expect? • What are the costs of a renewable energy product priced at only the levelized costs? • What is the range of stranded asset costs that could arise for states who need to deregulate?
Utility Subscription Expansion 2	• Utility expands subscription programs beyond previous expansion to satisfy C&I demand. • Utility develops more RE than necessary for RPS or to replace retiring fossil • Amount of RE provided is equal to the amount assumed in the supply choice pathway • Stranded assets are considered	• If the utility developed a similar C&I renewable energy program that mirrored retail products in the previous pathway, how would the stranded asset costs spread over the C&I customers?

Finally, for each state, the results of the pathways analysis are mapped into two scenarios: a **"moderate reform scenario"** to present near-term opportunities and a **"structural reform scenario"** to present long-term opportunities through 2030. In addition to these two scenarios, we also report a state's expected renewable energy deployment under the **"status quo"**. These labels are simply to provide context for tradeoffs between current opportunities and policy reforms. Generally, the moderate reform scenario reflects near-term opportunities that require either cooperation from state governments or utilities, but not major regulatory framework overhauls. In contrast, the structural reform scenario results in major reforms that will likely require consensus between many stakeholders to result in major structural policy reforms. We define these scenarios in Table 5.

Table 5
Scenario Descriptions

Scenarios	Description
Status Quo	Reflects the business-as-usual amount of renewable energy development as informed by announced procurements and renewable procurement mandates.
Moderate Reform Scenario	Reflects the potential impact of expanding utility subscription programs or state renewable procurement mandates, without major structural changes to the electricity market.
Structural Reform Scenario	Reflects the potential impact of major structural policy reforms, such as introducing supply choices for C&I customers.

These scenarios are then evaluated with the following metrics:

- <u>**Capacity of new renewable energy to meet potential:**</u> Quantifies the amount of renewable capacity that could potentially be developed in gigawatts (GW).
- <u>**Percent of C&I customer demand**</u> with access to 100 percent renewable energy supply in 2030.[20]
- <u>**Cost of renewable energy procurement:**</u> The cost of renewable energy procurement for a customer including the cost of energy, utility transmission and distribution charges (T&D), and premium for renewable procurement (as applicable), in (c/kWh).

An estimate of GHG reductions that would result from the development of renewable capacity to meet all customers with access to renewables was also evaluated for each of the sample states.

To evaluate the pathways, scenarios and metrics were evaluated by first estimating the amount of potential new renewable energy generation available to customers through 2030. To do this, first the amount of fossil fuel capacity expected to retire (in excess of the capacity already to be replaced in the status quo scenario) is estimated by assuming fossil plants with ages beyond 45 years retire. If assumed retirements are in excess of what needs to be replaced in the status quo (i.e. to meet an RPS), this provides an opportunity to increase renewable energy deployment without stranding fossil plants. At high penetrations of renewables, system reliability investments will likely be needed to accompany further renewable development; this is not considered in this analysis. In

[20] 2030 demand is assumed to be equal to 2018 demand given uncertainties remain about state-level electrification and efficiency.

jurisdictions where a large amount of existing generation capacity is retiring (in excess of the capacity already to be replaced with renewables as of 2030), *an assumption was made that this replacement capacity could be developed into a C&I subscription program*. For expanded state mandates, additional renewable development was accounted in order for the state to meet an expanded target, usually 10-15 percentage points higher than the current target. Lastly, for the supply choice pathway, the potential to develop renewable energy is unbounded and could theoretically serve all C&I customers. In our analysis, we use the historical retail adoption rate of C&I customers, 32 percent, when analyzing the impact of C&I customers in the state are provided with supply choices to guide the potential development.[21]

Costs presented for each state are the costs to procure renewable energy and are calculated based on the resource development of each pathway. *For status quo*, utility subscription expansion and expanded state mandates, costs of renewable procurement are assumed to be structured similarly to current utility subscription programs: the summation of average retail electricity costs and a premium for renewable energy procurement. Average retail electricity costs are adjusted based on estimated changes to the electricity mix under each scenario, and additional charges such as transmission and distributions are assumed to remain constant. Given the uncertainty of future renewable energy costs, both the cost component of average energy and the renewable procurement premium are evaluated as ranges. The range of levelized costs of renewable energy are set by the National Renewable Energy Laboratory (NREL) Annual Technology Baseline study, with costs adjusted for local state capacity factors.[22] As more renewables are added in status quo, utility subscription expansion, and expanded state mandate scenarios, the average grid electricity costs decline. For the procurement premiums, states where the forecasted average levelized renewable energy costs are lower than estimated energy costs, are assumed to have a premium that ranges from zero to the current premium. For states where this is not the case, premiums range from the current premium to twice the current premium. Details of the cost modeling are discussed in Appendix B.

For the supply choice pathway, costs are a summation of the levelized costs of renewable energy, an assumed 10 percent retailer premium on energy cost, estimated non-energy costs (transmission, distribution, etc.), and stranded costs. Stranded costs are calculated by assuming a range of 25-75

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21 Data from EIA (Form EIA-861).

22 "Annual Technology Baseline," National Renewable Energy Laboratory, 2019, accessed January 21, 2020.

percent of the current net-asset value in a state is socialized across all customer classes over 15 years. We recognize that a full implementation of retail choice would require significant cost analysis, which is not addressed in this report. The range of stranded costs, rather, presents a simple estimate of the likely range of costs that could be incurred for introducing Supply Choice for C&I Customers. For the "Utility Subscription Expansion 2" pathway, the portion of the stranded asset range that is only attributable to the utility program is socialized over subscribing C&I customers, also over 15 years.

The use of wide ranges for levelized renewable energy costs, renewable procurement premiums, and stranded costs reflects the inherent uncertainty of estimating future costs. Future costs are highly dependent on future state/regulatory, system operator, and federal policy decisions. These include policies to promote or integrate renewables (or lack thereof), mandates, technology evolution, etc. This is especially true for utilities that provide supply choice for their customers, with costs that are dependent on how state legislatures and commissions allow utilities to realize regulated returns or transfer the costs of regulated assets.

Data sources that informed the quantitative analysis in this study are from the Energy Information Agency (EIA),[23] SNL Energy (SNL),[24] Environmental Protection Agency (EPA),[25] National Renewable Energy Laboratory,[26] FERC Form 1 fillings, REBA's Deal Tracker, and various utility filings with local commissions. Below, Table 6 summarizes specific data sources.

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23 "State Electricity Profiles," U.S Energy Information Administration, December 31, 2019, accessed January 21, 2020.

24 S&P Global Market Intelligence Database.

25 "Emissions & Generation Resource Integrated Database (eGRID)," U.S. Environmental Protection Agency, accessed January 22, 2020.

26 "Annual Technology Baseline," National Renewable Energy Laboratory, accessed January 22, 2020.

Table 6: Raw Data Sources

Data	Raw Data Source
Historical generation of existing power generation by technology	EIA and SNL
Individual power plant generation, age, and emissions	EPA
Planned plant additions by state and technology	EIA, SNL, state commission filings and documents
Technical renewable potential by state	NREL
Historical energy power prices	EIA, utility filings, SNL
Historical electricity sale data by customer class	EIA
Historical C&I customer costs by customer class by cost type (wholesale energy, and transmission and distribution)	EIA and state commission filings and documents
Historical retail sales in the U.S. by customer class	EIA
Current corporate PPAs and green tariff subscriptions	REBA Deal Tracker
Performance of new renewables (capacity factors) by technology based on each state's natural renewable resources	EIA
Cost projections of new renewable energy resources up until 2030	NREL
Summarized state profiles, including announced RPSs, relevant policy news, and utility news	Multiple
Capacity and generation data for renewable power plants currently contracted to provide generation to existing utility subscription programs	Utility tariff filings
Net book value of utility generation assets	FERC Form 1 filings
Historical retail sales in the U.S. by customer class	EIA
Current corporate PPAs and green tariff subscriptions	REBA Deal Tracker
Performance of new renewables (capacity factors) by technology based on each state's natural renewable resources	EIA
Cost projections of new renewable energy resources up until 2030	NREL
Summarized state profiles, including announced RPSs, relevant policy news, and utility news	Multiple

IV. State Policy Pathways

This section evaluates various policy pathways and scenarios for the eight sample states: Arizona, California, Colorado, Georgia, Massachusetts, Minnesota, North Carolina, and Virginia. While the analysis presented here is state-specific, high-level findings about the viability of different pathways are largely transferable to other states not analyzed in this study with similar structural features.

A. Arizona

STATE PROFILE

With no centrally organized wholesale market and no supply choice in Arizona, incumbent utilities Arizona Public Service (APS), Tucson Electric Power (TEP), and Salt River Project control most energy procurement for Arizona customers. Table 7 presents a state profile of Arizona highlighting market structure, existing approaches to procure renewable energy for customers, current policy landscape, and a list of the barriers for customers to procure renewable energy.

Table 7
Arizona: State Profile

Structural Features	**RTO Participation:** No (Arizona Public Service and Salt River Project part of CAISO Energy Imbalance Market)
	Supply Choice: No
	State/Utility Goals: • **Mandatory:** RPS of 15 percent by 2025.[27] • **Voluntary:** Arizona Public Service (APS) has announced several goals about adding new renewable energy, including issuing several RFPs.[28]
Existing RE Procurement Approach	• Enter into bilateral contracts through one-off utility sleeve contracts. • Procure RE through APS corporate green subscription program.[29]
Current Policy Landscape	Without an organized wholesale market and no supply choice, customers' only options to procure renewable energy are through utility programs and one-off sleeve contracts. Arizona Public Service (APS) has two corporate Green Power plans; both offer relatively cost-effective renewable energy. Arizona is currently considering supply choice and increasing its RPS requirements.[30]
Barriers	**Supply of RE:** Lack of centrally organized wholesale market limits supply to utility IRP procurements and PURPA facilities.
	Availability of RE Products/Contracts: Limited to utility programs, which are dictated by the utility procurements.
	Ease of Procuring RE Products/Contracts: Aside from limited APS programs, high effort and information requirement to procure sleeve contracts through utility.
	Cost of RE Products/Contracts: APS programs relatively low cost, but still charges a premium for renewable electricity.

Currently, APS participates in the Western Energy Imbalance Market ("EIM"), a real-time only energy market, operated by the California Independent System Operator (CAISO). While some interstate wholesale electricity transactions occur, incumbent utilities still generate over 80 percent of the state's electricity. More than half of Arizona's generation mix is provided by fossil generation, while a significant amount of nuclear generation along with renewables make up the

27 "Renewable Energy Standard & Tariff," Arizona Corporation Commission, accessed January 21, 2020.

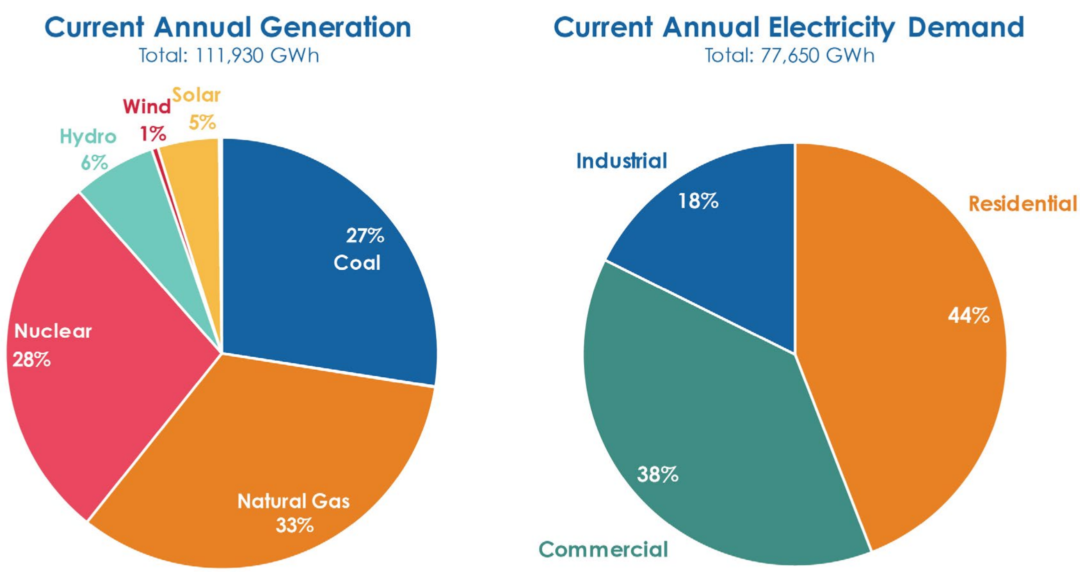
28 "APS moving forward to bring new clean-energy projects online for new customers," Arizona Public Service, April 3, 2019, accessed January 21, 2020.

29 "Rate Rider GPS-1," Arizona Public Service, July 1, 2017, accessed January 21, 2020.

30 Ryan Randazzo, "Choose your own electric company in Arizona? 7 things to know about deregulation," AZCentral, August 6, 2019.

rest (Figure 3).[31] Arizona's current RPS, 15 percent RE by 2025, is much lower compared to other states.[32, 33] In 2018, voters rejected a 50 percent renewable energy mandate despite the state's strong solar resources with nearly 70 percent of the vote.[34, 35]

Figure 3
Arizona: 2018 Annual in-State Electricity Generation and Demand



Notes: Source: EIA (2018). Transportation demand accounts for <0.01% of total electricity demand, and therefore excluded in this figure.

In Arizona, customer options to procure renewable energy are limited to utility offerings. APS has two corporate green power plans.[36] Both offer relatively cost-effective RE in comparison to utility programs elsewhere in the country, but still charge premiums in excess of standard service rates

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31 5,000 MW of renewable energy (including hydropower) was installed by 2018. The weighted average C&I retail cost was 9.4¢ per kWh ($94/MWh) in 2018.

32 Randazzo, 2019.

33 Bret Jaspers, "Arizona could make major changes to renewable-energy mandate," Cronkite News, August 2, 2019.

34 Gavin Blade, ""Ballot initiative flops masks strong election for clean energy," Utility Dive, November 7, 2018.

35 The forecasted average levelized cost ranges from $17 to $27 per MWh of solar energy and from $54 to $76 per MWh for wind in the 2020 to 2030 timeframe.

36 The renewable energy procurement premium in Arizona is modeled based on the APS Green Choice program, with a premium 1.02¢ per kilowatt-hour (kWh) and assumed to remain the same for the utility subscription expansion and the RPS expansion.

and require a yearly commitment. TEP has similar programs, but it covers far fewer customers. APS has also provided sleeved contracts for a few select customers,[37] but does not have a large-scale sleeve program for most customers.

Notably, Arizona's stakeholders are currently considering deregulation.[38] On August 17, 2018, the Arizona Corporation Commission opened a new docket (Docket No. RU-00000A-18-0284) to explore a wide range of energy rules including retail deregulation.[39]

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37 Herman K. Trabish, "The other death spiral utilities are beginning to deal with," Utility Dive, August 6, 2015.

38 Randazzo, 2019.

39 A recent report by the Arizona Energy Policy Group supported deregulation, citing the potential to decrease rates and increase customer satisfaction. However, the report also cites that historical examples of deregulation have not always resulted in price decreases. See: Lisa M. Quilici al., "Retail Competition in Electricity," Concentric Energy Advisors, July 23, 2019, accessed January 22, 2020.

POLICY PATHWAYS

Policy pathways analyzed in Arizona are provided in Table 8. These include Utility Subscription Expansion, RPS Expansion to 30 percent, and Introduction of supply choice for C&I Customers.

Table 8
Arizona: Pathway Assumptions and Takeaways

Pathways for 2030	Assumptions	Takeaways for RE Buyer
Status Quo	• Current 15% RPS is met • Utility subscription programs remain unchanged*	• A portion of grid electricity is provided by renewable energy • Options for buyers seeking additional renewable energy remain limited to utility subscription programs and PPAs
Utility Subscription Expansion	• Utility subscription programs are expanded with renewable development • RE amount for program expansion estimated using likely fossil fuel retirement (by age) beyond the new RE needed for current RPS	• Expanded utility program provide incremental options for buyers • Option remain limited to utility subscription programs and sleeved PPAs
RPS Expansion	• Expanded 30% RPS is met • Utility subscription programs remain unchanged	• A larger share of average grid electricity is provided by renewable energy • Options for buyers remain limited to utility subscription programs and sleeved PPAs
Supply Choice for C&I Customers	• Supply choice for C&I customers is introduced • Average historical adoption of retail choice assumed, based on U.S. retail adoption data • RE supply provided by new renewables • Assumes perfect procurement of RE to meet customer load (no storage or backup generation costs) • Stranded assets are considered	• Options for buyers seeking additional renewable energy expand to competitive retail providers • Stranded assets add costs • Scalable to all C&I customers

Note: Utility Subscription Expansion 2 not considered given the amount of retiring generation that opens up RE deployment for a utility subscription expansion is larger than the amount needed to provide supply choice for C&I customers. *APS subscription program information is limited; capacity or subscription data could not be found in public resources.

Applying the three policy pathways to Arizona, Figures 4 and 5 present the clean energy generation potential, capacity, and costs for each pathway. Results indicate that, in 2030:

- **Status Quo** will result in 17 percent of C&I customer demand with access to 100 percent clean energy and 1,045 MW of new renewable capacity to meet C&I customer demand for renewables, primarily through grid average clean energy deliveries by the current RPS. The cost of 100 percent energy procurement through the current utility subscription program (subject to availability) is estimated to be 9.36¢ to 10.45¢ per kWh, which includes the subscription premium.[40]

- **RPS Expansion** increases the share of C&I customer demand that can be met with 100 percent clean energy to 32 percent, providing up to 3,661 MW of new renewable capacity to meet C&I customer demand for renewables. This reduces subscription procurement costs to 9.20¢ to 10.46¢ per kWh indirectly, as the energy cost in the standard retail rate declines as more renewables are added to the grid.

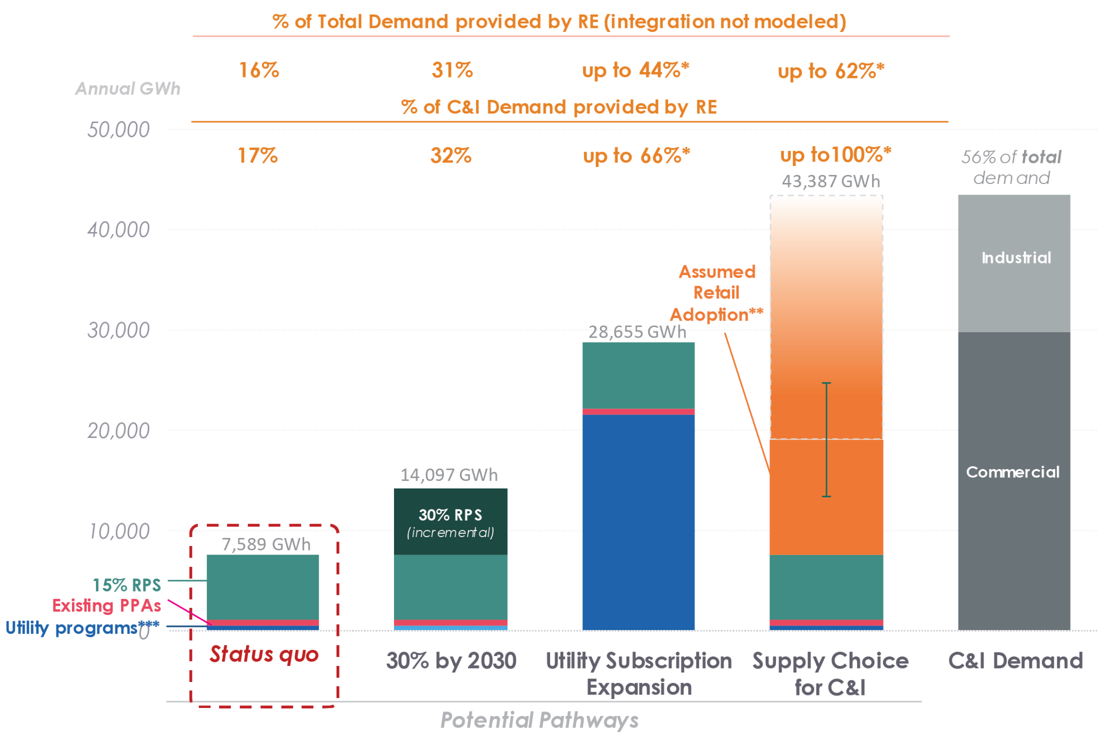
- **Utility Subscription Expansion** pathway implies a large renewable potential in Arizona, due to the size of fossil generation capacity likely to retire by 2030. Along with the current RPS, the Utility Subscription Expansion pathway has the potential to cover up to 66 percent of C&I customer demand and increase new state renewable energy capacity to 9,513 MW to meet demand for renewables. This pathway reduces subscription procurement costs to 8.82¢ to 10.47¢ per kWh indirectly, as the energy cost in the standard retail rate declines further as more renewables are added to the grid.

- **Providing Supply Choice for C&I Customers**, as in many other states, has a theoretical potential to supply all C&I customer demand. However, in reality, it is dependent both on the retail offerings and customer demand. Without accounting for additional stranded costs, the costs of delivery for a renewable retail product is estimated to be 8.51¢ to 9.79¢ per kWh, lower than those estimated under other pathways. However, accounting for the potential amount of stranded costs that may materialize when new supply choice displace additional conventional generation, the costs may increase by 0.50¢ to 1.50¢ per

[40] The renewable energy procurement premium in Arizona is modeled based on the APS Green Choice program with a premium 1.02¢ per kWh.

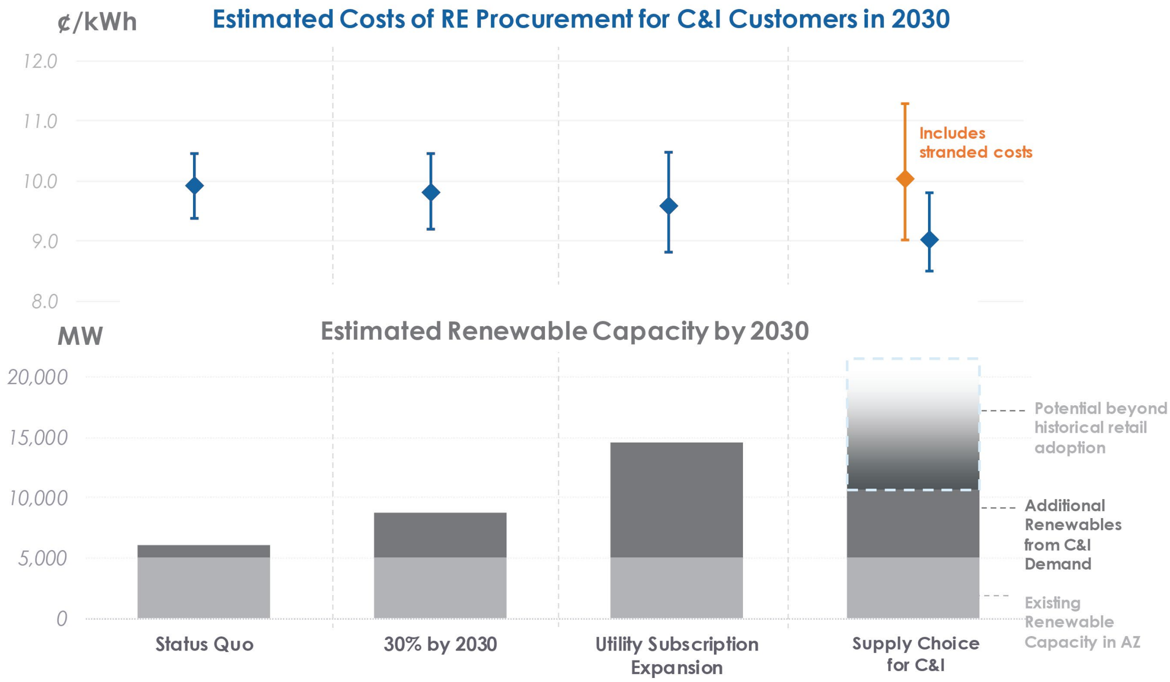
kWh, which could reduce the immediate financial value of introducing supply choice to customers.

Figure 4
Arizona: Potential Policy Pathways to Increase C&I Access to Renewable Energy by 2030



Note: While the solid orange bar shows historical adoption, providing supply choice has the potential to cover all C&I customer demand. Utility programs exclude APS subscription program due to lack of generation data. % of Total Demand and % of C&I Demand provided by RE estimates the percentage of total load and C&I load met by renewable energy, respectively. *Subject to customer adoption. **Based on historical C&I adoption rate of 32% (excluding Texas). Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents. ***Excludes APS subscription program.

Figure 5
Arizona: Policy Pathway Estimated Capacity and Cost Effects



Note: Cost bounds reflect range of projected renewable energy costs and range of possible stranded assets (as applicable). Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

RECAP

Distilling the pathways into reform scenarios, the Utility Subscription Expansion is selected as the moderate reform scenario and Supply Choice for C&I Customers is chosen as the structural reform scenario (Table 9). Given the large amount of potential replacement capacity that could be utilized for expanded C&I subscription programs, the Utility Subscription Expansion provides a near-term opportunity for increasing procurement options without requiring market structure overhauls. This would require working with the Arizona utilities to approve new renewable procurements and tariffs to expand subscription programs. In the long term, providing supply choice to C&I customers has an opportunity to reduce procurement costs given the levelized costs of renewables with additional transmission charges are estimated to be below current rates (Figure 5). However, stranded costs from introducing supply choice present a risk that might increase costs by 0.50¢ to 1.50¢ per kWh, which could significantly reduce the financial value of providing supply choice to customers. Despite the technical potential to significantly increase C&I access to renewables through the moderate reform and structural reform scenarios, the true adoption potential remains a key uncertainty in this state.

Table 9
Arizona: Progress under Moderate and Structural Policy Pathways

Metrics	Scenarios		
	Status-Quo 15% Clean Energy Goal is accomplished	**Moderate Reform Scenario** Utility subscription program capacity is expanded	**Structural Reform Scenario** Supply Choice for C&I is introduced and historical adoption rate occurs
Additional capacity relative to status-quo	1,050 MW	up to 9,510 MW	5,650 MW to 15,430 MW
Percentage of overall C&I demand with access to RE	17%	up to 66%	44% to 100%
Number of C&I customers with access to RE*	57,500	up to 217,100	144,200 to 328,700
Number of C&I customers with access to 100% RE procurement option**	8,200	up to 167,800	94,900 to 328,700
Estimated Cost of RE Procurement for C&I***	9.36 to 10.45 ¢/kWh	8.82 to 10.47 ¢/kWh	9.01 to 11.29 ¢/kWh
Estimated greenhouse gas reduction from electricity generation	6%	up to 51%	30% to 80%

Note: *Calculation includes RE generation from RPS, utility subscription, and retail providers. **Calculation only includes RE generation from utility subscription and for providing supply choice to C&I customers and excludes generation from RPS. *** Includes stranded assets.

B. California

STATE PROFILE

California has a centrally organized wholesale market operated by the CAISO and has seen much development of renewable energy through corporate power purchasing agreements (PPAs) already. Table 10 presents a state profile of California highlighting market structure, existing approaches to procure renewable energy for customers, current policy landscape, and a list of the barriers for customers to procure renewable energy.

Table 10
California: State Profile

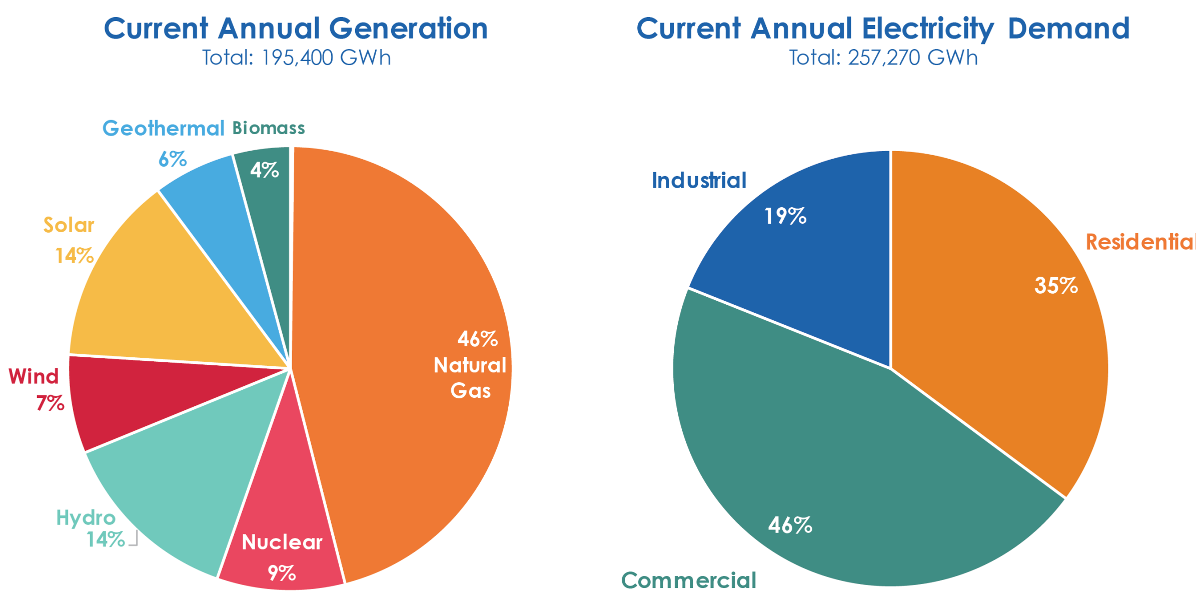
Structural Features	**RTO Participation:** CAISO
	Supply Choice: Limited access to Green Tariff/Shared Renewables Program (GTSR) members and limited Direct Access participants
	State/Utility Goals: • **Mandatory:** State renewable portfolio standard of 50% RE by 2025, 60% RE by 2030, and 100% clean energy by 2045 • **Voluntary:** Three investor-owned utilities (PG&E, SCE, and SDG&E) have exceeded state RPS goals.[41]
Existing RE Procurement Approach	• Procure RE through utility GTSR programs[42] • Procure RE through PPA • Procure RE through Direct Access provider (limited)
Current Policy Landscape	California has seen much development of renewable energy through corporate PPAs as a result of their access to CAISO and good renewable resources. In addition, the state has set aggressive RE goals that will result in much RE development over the next few decades. However, customer options to procure RE on their own remain limited to PPAs and the GTSR. Currently, California is considering expanding the GTSR and Direct Access programs.
Barriers	**Supply of RE:** With a centrally organized wholesale market, RE supply barriers are low (limited to economics of market).
	Availability of RE Products/Contracts: The limited GTSR program leaves most customers limited to PPAs.
	Ease of Procuring RE Products/Contracts: Aside from the GTSR program, high effort and information requirement for PPA.
	Cost of RE Products/Contracts: Without a transparent centralized REC market to drive prices down, prices will remain determined by PPA deals.

41 Amanda Singh, "2018 California Renewables Portfolio Standard," California Public Utilities Commission, November 2018, accessed January 21, 2020.

42 "Green Tariff/Shared Renewables Program (GTSR)," California Public Utilities Commission (CUPC), accessed January 21, 2020.

California generates over half of their in-state generation with emission-free resources (Figure 6).[43] The state's goals of 60 percent renewable energy by 2030 and 100 percent clean energy by 2045 are some of the most ambitious clean energy goals in the U.S., and will encourage substantial renewable development.[44] However, while power sector emissions have declined in California as they continue to be on track for their renewable portfolio standards (RPSs), growth in transportation, building, and industrial sectors have resulted in California to be far behind on their overall emission goals.[45]

Figure 6
California: 2018 Annual in-State Electricity Generation and Demand



Note: Source: EIA (2018). Transportation demand accounts for <0.4% of total electricity demand, and therefore excluded in this figure.

Options for customers to procure renewable energy products on their own remain limited to corporate PPAs, the Green Tariff Shared Renewables (GTSR) program, and the Direct Access program. The former is often reserved for large-scale buyers with resources to negotiate PPAs. The GTSR program is limited in scope, capped at 600 MW distributed among the three main utilities

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43 28,000 MW of renewable energy (including hydropower) was installed in Arizona by 2018. The weighted average C&I retail cost was 15.6¢ per kWh ($156/MWh) in 2018.

44 "Renewables Portfolio Standard (RPS) Program," CUPC, accessed January 4, 2020.

45 Herman K. Trabish, "California may be a climate leader, but it could be a century behind on its carbon goals: study," Utility Dive, October 29, 2019.

in the state.[46] Direct Access service is retail electric service where customers purchase electricity from a competitive provider called an Electric Service Provider (ESP), instead of from a regulated electric utility. However, the program limits the amount of electric load that ESPs may serve, based on a Commission-adopted three to five-year phase in schedule until the historical maximum is reached in each utility territory. In 2018, the California Public Utilities Commission (CPUC) expanded Direct Access to 4,000 GWh, 1.5 percent of 2018 load.[47] Effectively, these programs provide few options for corporate customers. Customer choice aggregation (CCA) has also become a popular option for aggregated loads (such as municipalities) due to relatively cost-competitive renewables.[48] However, much debate remains about the treatment of CCAs, such as the formulation of exit fees to compensate local utilities with diminishing load customers.[49, 50]

POLICY PATHWAYS

Policy pathways analyzed in California are presented in Table 11. These include Utility Subscription Expansion, Introducing Supply Choice to C&I Customers, and Utility Subscription Expansion 2.

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46 CUPC, "Green Tariff/Shared Renewable Program (GTSR)."

47 "An act to amend Section 365.1 of the Public Utilities Code, relating to electricity," California Senate Bill No. 237, Chapter 600. Approved September 20, 2019.

48 The forecasted average levelized costs from 2020 to 2030 of solar ranges $17 to $28 per MWh, and $51 to $71 per MWh for wind.

49 Trabish, Herman K., "Does C-C-A spell the end of the regulated electric utility in California?" Utility Dive, November 17, 2017.

50 Jeff St. John, "California to Hike Fees for Community Choice Aggregators, Direct Access Providers," Greentech Media, October 11, 2018.

Table 11
California: Pathway Assumptions and Takeaways

Pathways for 2030	Assumptions	Takeaways for RE Buyer
Status Quo	• Current 60% RPS is met • Utility subscription programs remain unchanged	• A portion of grid electricity is provided by renewable energy • Options for buyers seeking additional renewable energy remain limited to utility subscription programs and PPAs
Utility Subscription Expansion	• Fossil fuel retirement (by age) is not large to drive new RE deployment • Utility subscription program expansion is limited when RPS is already high • Even so, assume utility subscription programs will triple due to customer demand.	• Expanded utility program provide incremental options for buyers • Option remain limited to utility subscription programs and PPAs
Supply Choice for C&I Customers	• Supply choice for C&I customers is introduced • Average historical adoption of retail choice assumed, based on U.S. retail adoption data • RE supply provided by new renewables • Assumes perfect procurement of RE to meet customer load (no storage or backup generation costs) • Stranded assets are considered	• Options for buyers seeking additional renewable energy expand to competitive retail providers • Stranded assets add costs • Scalable to all C&I customers
Utility Subscription Expansion 2	• Utility expands subscription programs beyond previous expansion to satisfy C&I demand. • Amount of RE provided is equal to the amount assumed in the retail choice pathway • Stranded assets are considered	• Utility program expands to satisfy more C&I demand • Stranded assets add costs

Note: RPS Expansion is not considered given California's current RPS targets are already very ambitious.

Applying the three policy pathways to California, Figures 7 and 8 present the renewable energy generation potential, capacity, and costs for each pathway. Results indicate that, in 2030:

- **Status Quo** will result in 62 percent of C&I customer demand with access to clean energy and 12,488 MW of new renewable capacity to meet C&I customer demand for renewables, primarily through grid average clean energy deliveries by the current RPS. The cost of 100 percent energy procurement through the current utility subscription program (subject to availability) is estimated to be 15.36¢ to 16.74¢ per kWh, which includes the subscription premium.[51]

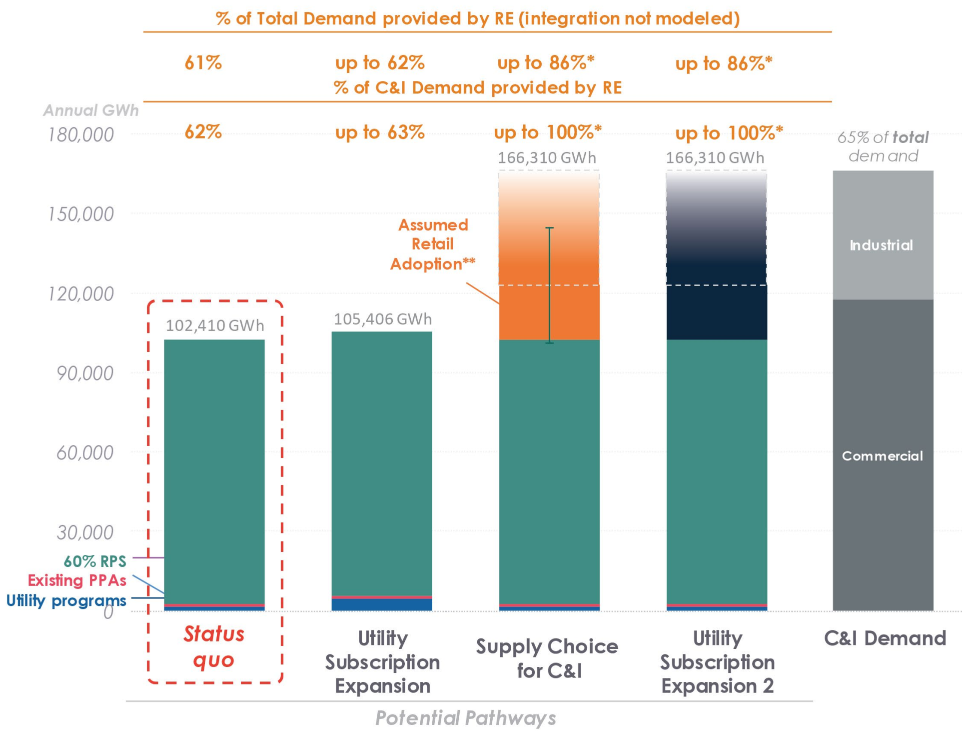
[51] The renewable energy premium is modeled based on the GTSR program offerings for each utility, with an average premium of 1.25¢ per kWh.

- **Utility Subscription Expansion** pathway is treated differently in California than other states, as most of the fossil generation capacity likely to retire by 2030 will already be replaced by renewables to meet their aggressive RPS. Therefore, we assume a tripling of the GTSR program for the Utility Subscription Expansion pathway. Along with the current RPS, the Utility Subscription Expansion pathway has the potential to cover up to 63 percent of C&I customer demand and increase new state renewable energy capacity to 13,731 MW to meet C&I customer demand for renewables. This pathway's procurement costs are 15.35¢ to 16.75¢ per kWh indirectly, effectively the same cost as the status quo.

- **Providing Supply Choice for C&I Customers**, as in many other states, has a theoretical potential to supply all C&I customer demand. However, in reality, it is dependent both on the retail offerings and customer demand. Without considering any potential stranded costs, the costs of delivery for a renewable retail product is estimated to be 14.80¢ to 16.35¢ per kWh, lower than those estimated under other pathways. However, potential level of stranded costs presents a risk that might increase costs by 0.21¢ to ¢0.64 per kWh, which could reduce the cost advantage of obtaining choice for C&I customers.

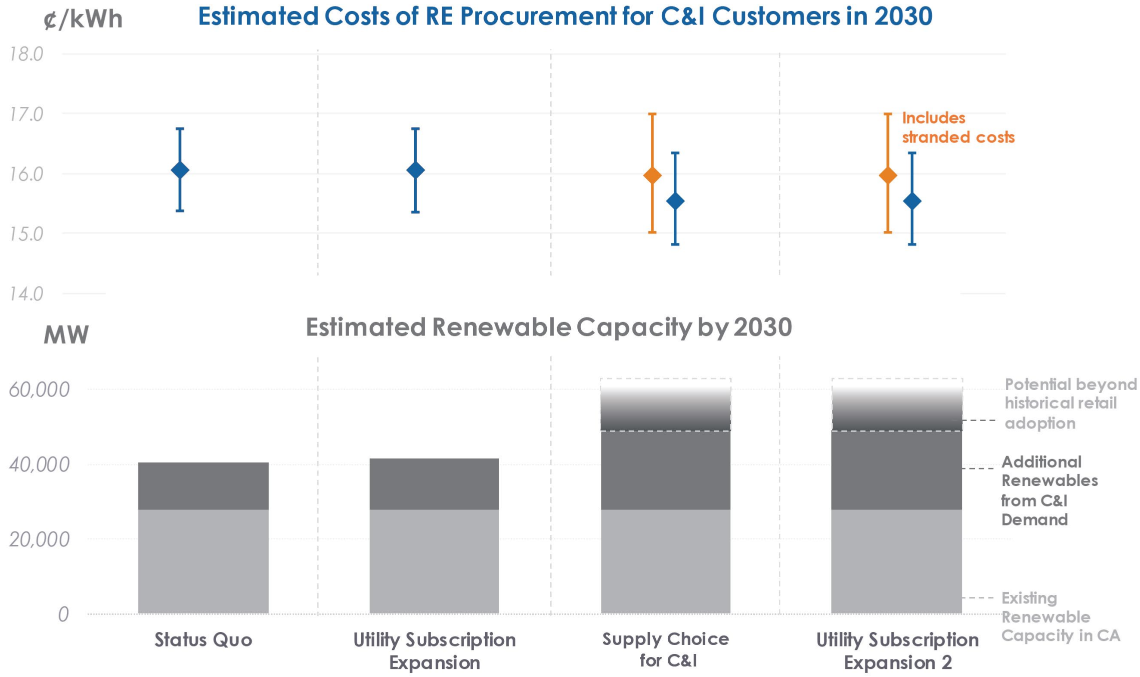
- **Utility Subscription Expansion 2** pathway expands the GTSR program to meet all of C&I demand, allowing similar access to renewables as the Supply Choice pathway but with the renewables provided by the utility. This spreads the stranded costs over a smaller customer base. Ultimately, cost estimates for the Utility Subscription Expansion 2 pathway are similar to Supply Choice pathway given the analysis' framework.

Figure 7
California: Potential Policy Pathways to Increase C&I Access to Renewable Energy by 2030



Note: While the solid orange bar shows historical adoption, providing supply choice to C&I customers has the potential to cover all C&I customer demand. % of Total Demand and % of C&I Demand provided by RE estimates the percentage of total load and C&I load met by renewable energy, respectively. *Subject to customer adoption. **Based on historical C&I adoption rate of 32% (excluding Texas). Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

Figure 8
California: Policy Pathway Estimated Effects



Note: Cost bounds reflect range of projected RE costs and range of possible stranded assets (as applicable). Costs between Supply Choice and Expansion 2 are similar because less stranded costs get spread over a smaller customer base. Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

RECAP

In California, all pathways result in a high percentage of C&I load met by renewable energy due to existing aggressive renewable mandates. However, individual procurement options for C&I customers wanting to go beyond state goals remain limited. Distilling the pathways into reform scenarios, the Utility Subscription Expansion is selected as the moderate reform scenario and Supply Choice for C&I Customers is chosen as the structural reform scenario (Table 12). The Utility Subscription Expansion provides a near-term opportunity for increasing procurement options without requiring market structure overhauls. This would require working with California regulators to expand the GTSR. In the long term, providing supply choice for C&I customers has an opportunity to reduce procurement costs given the levelized costs of renewables with additional transmission charges are estimated to be below current rates (Figure 8). However, any additional can present a risk that might increase costs by 0.21¢ to 0.64¢ per kWh, which could remove the financial value of providing choice to customers.

Table 12
California: Progress under Moderate and Structural Policy Pathways

Metrics	Scenarios		
	Status-Quo 60% Clean Energy Goal is accomplished	Moderate Reform Scenario Utility subscription program capacity is tripled	Structural Reform Scenario Supply Choice for C&I is introduced and historical adoption rate occurs
Additional capacity relative to status-quo	12,590 MW	up to 13,730 MW	20,970 MW to 26,900 MW
Percentage of overall C&I demand with access to RE	62%	up to 63%	74% to 100%
Number of C&I customers with access to RE*	1,135,400	up to 1,168,600	1,362,000 to 1,843,800
Number of C&I customers with access to 100% RE procurement option**	29,100	up to 62,300	255,600 to 1,843,800
Estimated Cost of RE Procurement for C&I***	15.36 to 16.74 ¢/kWh	15.35 to 16.75 ¢/kWh	15.02 to 16.98 ¢/kWh
Estimated greenhouse gas reduction from electricity generation	16%	up to 18%	27% to 55%

*Calculation includes RE generation from RPS, utility subscription, and retail providers.
Calculation only includes RE generation from utility subscription and supply choice and excludes generation from RPS. * Includes estimated stranded costs.

C. Colorado

STATE PROFILE

Colorado's lack of a centrally organized wholesale market and supply choice limit renewable development and procurement options for customers to those programs offered by utilities and cooperatives. Table 13 presents a state profile of Colorado highlighting market structure, existing approaches to procuring renewable energy for customers, current policy landscape, and a list of the barriers for customers to procure renewable energy.

Table 13
Colorado: State Profile

Structural Features	**RTO Participation:** No
	Supply Choice: No
	State/Utility Goals: • **Mandatory:** State goal of 30% clean energy by 2020.[52] • **Voluntary:** Xcel energy has a goal of 100% carbon-free energy by 2050.[53] The state has aspirational goal of 90% economy-wide emission reductions by 2050, and the governor recently unveiled a roadmap of the state's path to 100% renewable energy by 2040.[54]

Existing RE Procurement Approach	• Procure RE through Xcel subscription programs
	  ○ Windsource
	  ○ Renewable*Connect

Current Policy Landscape	Colorado's lack of an organized wholesale market and supply choice limits renewable energy products for customers to the programs offered by their utilities and cooperatives. Since 2017, Colorado utilities, including Xcel, have discussed whether to join an RTO. In December 2019, four Colorado utilities, Xcel Energy, Black Hills Colorado Electric, Colorado Springs Utilities, and Platte River Power Authority announced that they plan to join the Western Energy Imbalance Market (WEIM), operated by the CAISO.
Barriers	**Supply of RE:** Without a centrally organized wholesale market, RE supply is limited to utilities plans, PURPA facilities, and co-op procurement.
	Availability of RE Products/Contracts: Xcel programs are readily available; however, there are limited offerings in co-op regions.
	Ease of Procuring RE Products/Contracts: Xcel programs have a high ease of procurement.
	Cost of RE Products/Contracts: Xcel programs offer relatively low rates, but the lack of a transparent REC market prevents market forces from driving down REC prices.

52 "Renewable Energy Standard," Colorado Energy Office, accessed January 21, 2020.

53 "Your Clean Energy Future," Xcel Energy.

54 Ryan Osborne, "How Gov. Polis plans to get Colorado using 100% renewable energy by 2040," The Denver Channel, May 30, 2019.

Since 2017, Colorado utilities including Xcel have discussed whether to join an RTO, either SPP or Western EIM. Governor Jared Polis signed Senate Bill 19-236 in May 2019, which among other provisions, directed the PUC to analyze the potential benefits to joining an RTO.[55] In December 2019, four Colorado utilities announced that they will be joining California's Western EIM. [56]

Fossil fuels still dominate Colorado's generation mix, making up more than half of in-state generation (Figure 9).[57] Wind's favorable capacity factor has led to much development in recent years and both wind and solar resources are available in the state.[58] The state's renewable energy standard calls for at least 30 percent of electrical generation to come from renewable sources by 2020, and in May 2019, Governor Polis has set an aspirational goal of decarbonizing the state's economy 90 percent below 2005 levels by 2040.[59]

55 "An Act concerning the continuation of the public utilities commission, and, in connection therewith, implementing the recommendations contained in the 2018 sunset report by the Department of Regulatory Agencies and making an appropriation," Colorado Senate Bill 19-236. Approved May 30, 2019.

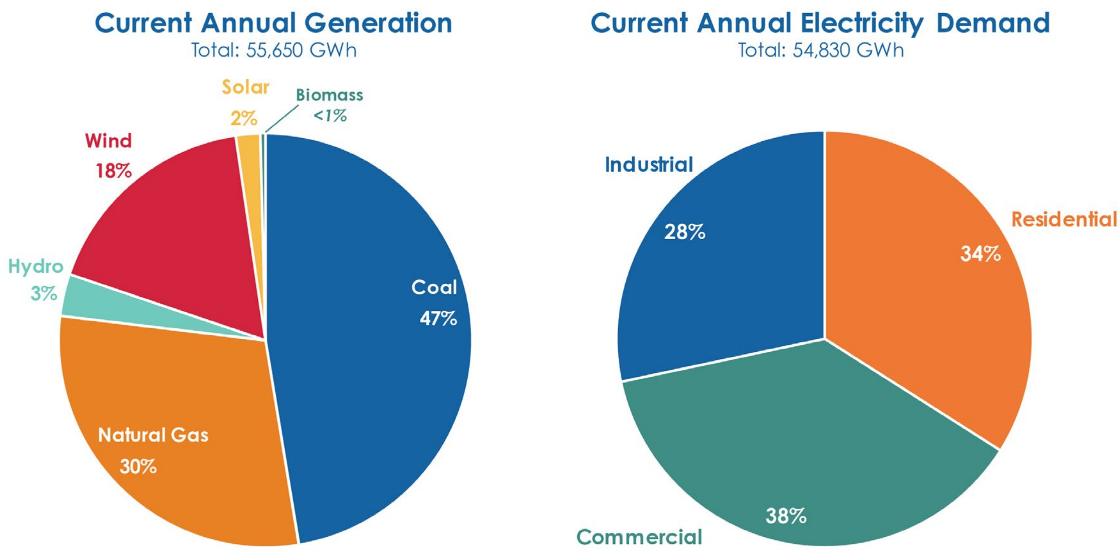
56 Catherine Morehouse, "Colorado Gov Polis unveils roadmap to 100% renewables by 2040, signs 11 clean energy bills," Utility Dive, June 3, 2019.

57 4,900 MW of renewable energy (including hydropower) was installed in Arizona by 2018. The weighted average C&I retail cost was 8.9¢ per kWh ($88/MWh) in 2018.

58 The forecasted average levelized costs for renewable energy from 2020 to 2030 of solar ranges from $19 to $31 per MWh, and from $29 to $35 per MWh for wind.

59 Morehouse, 2019.

Figure 9
Colorado: 2018 Annual in-State Electricity Generation and Demand



Note: Source: EIA (2018). Transportation demand accounts for <0.2% of total electricity demand, and therefore excluded in this figure.

Xcel Colorado currently has two renewable subscription programs. Xcel Renewable*Connect offered generation from a specific renewable project and was quickly fully subscribed. Xcel Windsource continues to provide wind power from utility procurements on month-to-month contracts and charges a modest premium. [60]

POLICY PATHWAYS

Policy pathways analyzed in Colorado are provided in Table 14. These include Utility Subscription Expansion, RPS Expansion to 40 percent, and Introducing Supply Choice to C&I Customers.

60 Xcel Energy, "Renewable*Connect," accessed January 21, 2020.

Table 14
Colorado: Pathway Assumptions and Takeaways

Pathways for 2030	Assumptions	Takeaways for RE Buyer
Status Quo	• Current 30% RPS is met • Utility subscription programs remain unchanged*	• A portion of grid electricity is provided by renewable energy • Options for buyers seeking additional renewable energy remain limited to utility subscription programs and PPAs
Utility Subscription Expansion	• Utility subscription programs are expanded with renewable development • RE amount for program expansion estimated using likely fossil fuel retirement (by age) beyond the new RE needed for current RPS	• Expanded utility program provide incremental options for buyers • Option remain limited to utility subscription programs and PPAs
RPS Expansion	• Expanded 40% RPS is met • Utility subscription programs remain unchanged	• A larger share of average grid electricity is provided by renewable energy • Options for buyers remain limited to utility subscription programs and PPAs
Supply Choice for C&I Customers	• Supply choice for C&I customers is introduced • Average historical adoption of retail choice assumed, based on U.S. retail adoption data • RE supply provided by new renewables • Assumes perfect procurement of RE to meet customer load (no storage or backup generation costs) • Stranded assets are considered	• Options for buyers seeking additional renewable energy expand to competitive retail providers • Stranded assets add costs • Scalable to all C&I customers

Note: Utility Subscription Expansion 2 is not considered given the amount of assumed generation that would retire to allow for a utility subscription expansion is larger than the amount assumed to provide supply choice to C&I customers. *Xcel Colorado Windsource program information not available, generation for this program not included in results.

Applying the three policy pathways to Colorado, Figures 10 and 11 presents the clean energy generation potential, capacity, and costs for each pathway. Results indicate that, in 2030:

- **Status Quo** will result in 31 percent of C&I customer demand with access to clean energy and 930 MW of new renewable capacity to meet C&I customer demand for renewables, primarily through grid average clean energy deliveries by the current RPS. The cost of 100 percent energy procurement through the current utility subscription program (subject to availability) is estimated to be 8.86¢ to 9.61¢ per kWh, which includes the subscription premium.[61]

- **Expanded RPS** increases the share of C&I customer demand with access to clean energy to 41 percent providing up to 2,144 MW of new renewable capacity to meet C&I customer demand for renewables. This reduces subscription procurement costs to 8.83¢

[61] The renewable energy premium is modeled based on the monthly Xcel Renewable*Connect premium, with a premium of 0.70¢ per kWh.

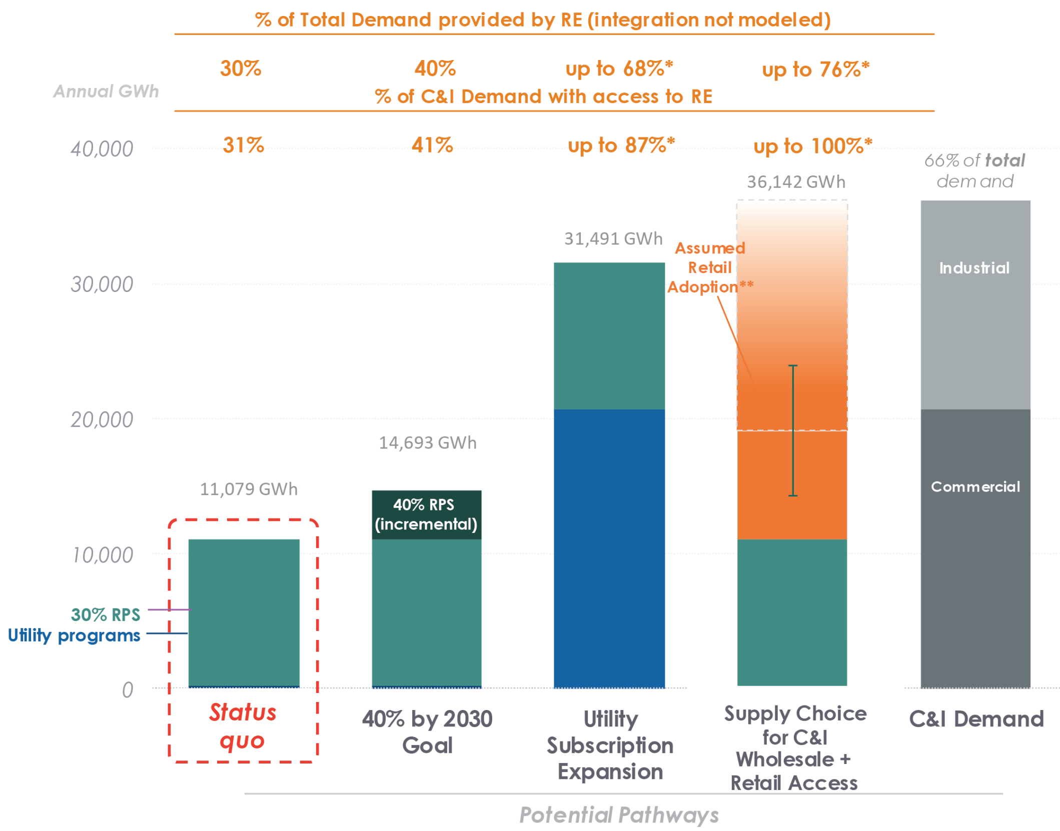
[61] Xcel Energy, "Renewable*Connect."

to 9.65¢ per kWh indirectly, as the energy cost in the standard retail rate declines as more renewables are added to the grid.

- **Utility Subscription Expansion** pathway implies a large renewable potential in Colorado, due to the sheer size of fossil generation capacity likely to retire by 2030. Along with the current RPS, the Utility Subscription Expansion pathway has the potential to cover up to 87 percent of C&I customer demand and increase new state renewable energy capacity to 7,786 MW to meet C&I customer demand for renewables. This pathway reduces subscription procurement costs to 8.68¢ to 9.81¢ per kWh indirectly, as the energy cost in the standard retail rate declines further as more renewables are added to the grid.

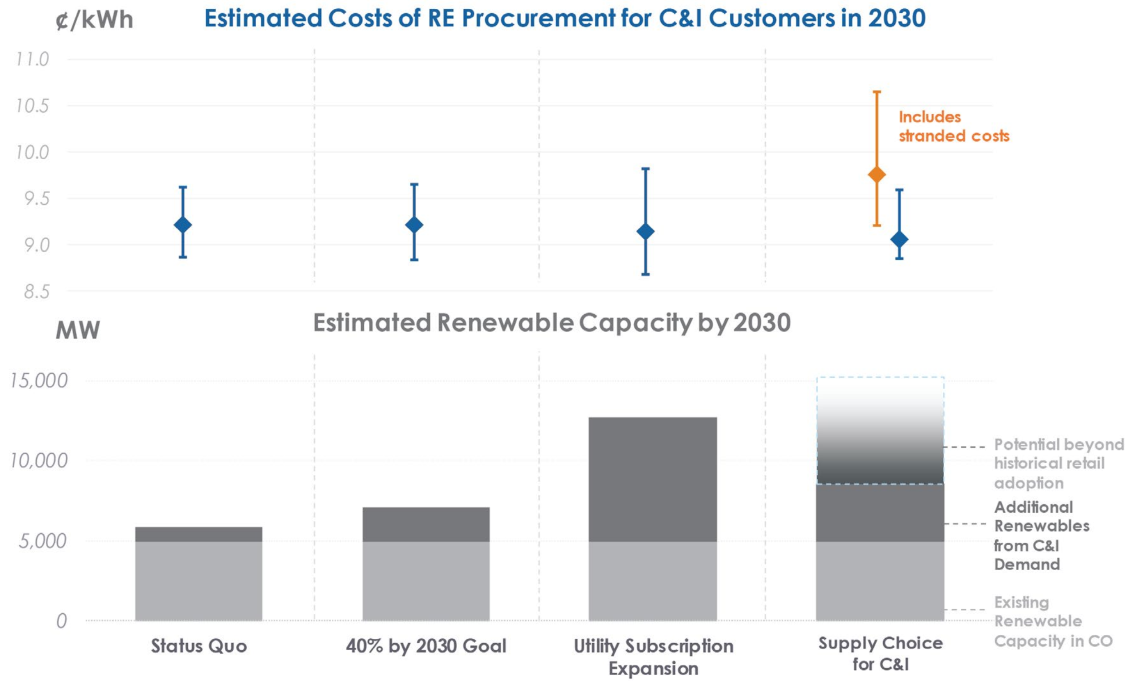
- **Supply Choice to C&I Customers**, as in many other states, has a theoretical potential to supply all C&I customer demand. However, it is dependent both on the retail offerings and customer demand. Without considering stranded costs, the costs of delivery for a renewable retail product is estimated to be 9.20¢ to 10.64¢ per kWh, lower than those estimated under other pathways. However, potential level of stranded costs presents a risk that might increase costs by 0.35¢ to 1.06¢ per kWh, which could reduce the financial value to customers.

Figure 10
Colorado: Potential Policy Pathways to Increase C&I Access to Renewable Energy by 2030



Note: While the solid orange bar shows historical adoption, providing supply choice to C&I customers has the potential to cover all C&I customer demand. % of Total Demand and % of C&I Demand provided by RE estimates the percentage of total load and C&I load met by renewable energy, respectively. *Subject to customer adoption. **Based on historical C&I adoption rate of 32% (excluding Texas). Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

Figure 11
Colorado: Policy Pathway Estimated Effects



Note: Cost bounds reflect range of projected renewable energy costs and range of possible stranded assets (as applicable). Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

RECAP

Distilling the pathways into reform scenarios, the Utility Subscription Expansion is selected as the moderate reform scenario and introducing Supply Choice to C&I Customers is chosen as the structural reform scenario (Table 15). Given the large amount of potential replacement capacity that could be utilized for expanded C&I subscription programs, the Utility Subscription Expansion provides a near-term opportunity for increasing procurement options without requiring market structure overhauls. This would require working with the Colorado utilities to approve new renewable procurements and tariffs to expand subscription programs. In the long term, providing supply choice to C&I Customers has an opportunity to lower procurement costs given the levelized costs of renewables with additional transmission charges are estimated to be below current rates. However, potential stranded costs present a risk that might increase costs by 0.35¢ to 1.06¢ per kWh, which could remove the financial value to customers. The adoption potential under this scenario also remains a key uncertainty given the constraint of using historical adoptions rates.

Table 15
Colorado: Progress under Moderate and Structural Policy Pathways

Metrics	Scenarios		
	Status-Quo 30% Clean Energy Goal is accomplished	**Moderate Reform Scenario** Utility subscription program capacity is expanded	**Structural Reform Scenario** Supply Choice for C&I is introduced
Additional capacity relative to status-quo	930 MW	up to 7,780 MW	3,620 MW to 9,350 MW
Percentage of overall C&I demand with access to RE	31%	up to 87%	53% to 100%
Number of C&I customers with access to RE*	118,600	up to 337,100	204,400 to 386,900
Number of C&I customers with access to 100% RE procurement option**	2,530	up to 221,000	88,300 to 386,900
Estimated Cost of RE Procurement for C&I***	8.86 to 9.61 ¢/kWh	8.68 to 9.81 ¢/kWh	9.01 to 11.36 ¢/kWh
Estimated greenhouse gas reduction from electricity generation	7%	up to 59%	28% to 71%

*Calculation includes RE generation from RPS, utility subscription, and retail providers. **Calculation only includes RE generation from utility subscription and supply choice for C&I customers and excludes generation from RPS. ***Includes stranded assets.

D. Georgia

STATE PROFILE

Georgia is not a member of a centrally organized wholesale market and currently has no statewide renewable mandate, although Atlanta has a citywide goal of 100 percent clean electricity by 2035. Table 16 presents a state profile of Georgia highlighting market structure, existing approaches to procure renewable energy for customers, current policy landscape, and a list of the barriers for customers to procure renewable energy.

Table 16
Georgia: State Profile

Structural Features	**RTO Participation:** No
	Supply Choice: Limited to loads over 0.9 MW, but little uptake due to one-time opportunity structure
	State/Utility Goals: • **Mandatory:** None • **Voluntary:** Georgia Power plans to have 22% of capacity met by renewables by the end of 2024,[62] and an aspirational 100% clean 2050 goal as part of Southern Company. City of Atlanta has a 100% clean electricity by 2035 goal.[63]
Existing RE Procurement Approach	Existing Georgia Power's C&I REDI program is fully subscribed, but recently approved IRP proposes to expand the program to the Customer Renewable Supply Procurement (CRSP) program.[64]
Current Policy Landscape	Customers in Georgia are limited to using utility programs and rely on utilities to increase the use of renewable energy supply subject to state commission approvals. Georgia Power developed the Commercial & Industrial Renewable Energy Development Initiative (C&I REDI) in April 2018, which is fully subscribed. Georgia Power has committed to new solar plants in recent fillings that have been approved by the state commission. In its 2019 integrated resource plan, Georgia Power has committed to expanding the C&I REDI program.[65]
Barriers	**Supply of RE:** Lack of centrally organized wholesale market limits RE supply to utility plans and PURPA facilities.
	Availability of RE Products/Contracts: No utility tariff or program available for new customers, but recent IRP includes expansion of C&I REDI program by nearly 1 GW.
	Ease of Procuring RE Products/Contracts: The expanded C&I REDI program will likely include similar barriers to previous program, such as application fees and large procurements. Program details are yet to be published.
	Cost of RE Products/Contracts: Fees raising the price of RE to beyond its market-based prices, rates remain subject to negotiations.

Georgia's power system is largely planned and operated by the vertically-integrated utility Georgia Power. While Georgia does allow for *limited* retail choice, the law's immediate entry into retail choice for new customers is restrictive. Fossil fuels dominate Georgia's generation mix, currently

62 "Georgia Power files 20-year plan to meet Georgia's future energy needs," Georgia Power, January 31, 2019, accessed January 21, 2020.

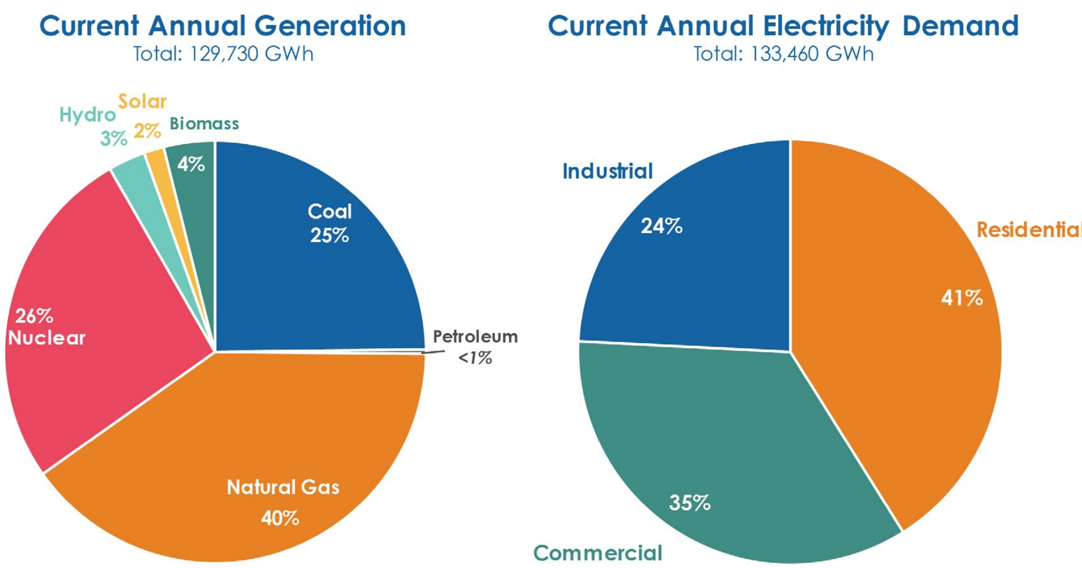
63 Jason Margolis, "How Atlanta plans to get to 100% green energy by 2035," Public Radio International, April 15, 2019, accessed January 21, 2020.

64 "2019 Integrated Resource Plan," Georgia Power, 2019, accessed January 21, 2020.

65 *Ibid.*

generating two-thirds of electricity (Figure 12).[66, 67] The remainder is made up mostly of nuclear generation with very low amounts of renewable energy. While there is no state renewable energy mandate, Georgia Power plans to have 22 percent of capacity met by renewables by the end of 2024 and has aspirational 100 percent clean 2050 goal as part of Southern Company.[68, 69] In its recent integrated resource plan, Georgia Power proposed adding up to 1,000 MW of renewables to increase its total renewable energy capacity to 18 percent by 2024.[70]

Figure 12
Georgia: 2018 Annual in-State Electricity Generation and Demand



Notes: Source: EIA (2018). Transportation demand accounts for <0.2% of total electricity demand, and therefore excluded in this figure.

66 3,000 MW of renewable energy (including hydropower) was installed in Arizona by 2018. The weighted average C&I retail cost was 8.1¢ per kWh ($81/MWh) in 2018.

67 The forecasted average levelized costs for renewable energy from 2020 to 2030 of solar ranges between $21 and $34 per MWh. Wind was not considered in Georgia.

68 "Planning for a low-carbon future," Southern Company, April 2018, accessed January 22, 2020.

69 Robert Walton, "Regulators unanimously approve Georgia Power plan, adding 80 MW storage," Utility Dive, July 17, 2019.

70 Georgia Power, January 31, 2019.

Georgia Power developed the Commercial & Industrial Renewable Energy Development Initiative (C&I REDI) in April 2018, which was met with much enthusiasm. The program is now fully subscribed with Google, Johnson & Johnson, Target and Walmart as customers.[71] As part of Georgia Power's most recent IRP, they have proposed a new Customer Renewable Supply Procurement (CRSP) program, modeled after the C&I REDI program, which will procure 950 MW of utility scale renewable resources available for subscription to new and existing customers.[72]

POLICY PATHWAYS

Policy pathways analyzed in Georgia are provided in Table 17. These include Utility Subscription Expansion, RPS Expansion to 30 percent, and introducing Supply Choice to C&I Customers.

Table 17
Georgia: Pathway Assumptions and Takeaways

Pathways for 2030	Assumptions	Takeaways for RE Buyer
Status Quo	• Current Georgia Power goal of 22% RE capacity is met • Utility subscription programs include recently announced C&I REDI expansion	• A portion of grid electricity is provided by renewable energy • Options for buyers seeking additional renewable energy remain limited to utility subscription programs and PPAs
Utility Subscription Expansion	• Utility subscription programs are expanded with renewable development • RE amount for program expansion estimated using likely fossil fuel retirement (by age) beyond the new RE needed for current RPS	• Expanded utility program provide incremental options for buyers • Option remain limited to utility subscription programs and PPAs
RPS Expansion	• Georgia adopts 25% RPS • Utility subscription programs remain unchanged	• A larger share of average grid electricity is provided by renewable energy • Options for buyers remain limited to utility subscription programs and PPAs
Supply Choice for C&I Customers	• Supply choice for C&I customers is introduced • Average historical adoption of retail choice assumed, based on U.S. retail adoption data • RE supply provided by new renewables • Assumes perfect procurement of RE to meet customer load (no storage or backup generation costs) • Stranded assets are considered	• Options for buyers seeking additional renewable energy expand to competitive retail providers • Stranded assets add costs • Scalable to all C&I customers

Note: Utility Subscription Expansion 2 not considered given the assumed amount of generation that would retire to make renewable resources available for a utility subscription expansion is larger than the amount needed to provide supply choice for C&I customers.

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71 Georgia Power, "Georgia Power to add 177 MW of solar resources for C&I REDI program," PR Newswire, April 9, 2018.

72 "2019 Integrated Resource Plan," Georgia Power.

Applying the three policy pathways to Georgia, Figure 13 and Figure 14 present the clean energy generation potential, capacity, and costs for each pathway. Results indicate that, in 2030:

- **Status Quo** will result in eight percent of C&I customer demand with access to clean energy and 1,263 MW of new renewable capacity to meet C&I customer demand for renewables. The cost of 100 percent energy procurement through the current utility subscription program (subject to availability) is estimated to be 8.03¢ to 8.5¢ per kWh, which includes the subscription premium.[73]

- **Expanded RPS** instates a state clean energy mandate of 25 percent (of total consumption, not just capacity), providing up to 9,633 MW of new renewable capacity to meet 29 percent C&I customer demand for renewables. This reduces subscription procurement costs to 7.71¢ to 8.46¢ per kWh indirectly, as the energy cost in the standard retail rate declines as more renewables are added to the grid.

- **Utility Subscription Expansion** pathway implies a large renewable potential in Georgia, due to the sheer size of fossil generation capacity likely to retire by 2030. Along with the current RPS, the Utility Subscription Expansion pathway has the potential to cover up to 43 percent of C&I customer demand and increase new state renewable energy capacity to 14,732 MW to meet C&I customer demand for renewables. This pathway reduces subscription procurement costs to 7.51¢ to 8.44¢ per kWh indirectly, as the energy cost in the standard retail rate declines further as more renewables are added to the grid.

- **Providing Supply Choice to C&I Customers**, as in many other states, has a theoretical potential to supply all C&I customer demand. However, it is dependent both on the retail offerings and customer demand. Without considering stranded costs, the costs of delivery for a renewable retail product is estimated to be 7.17¢ to 8.26¢ per kWh, significantly lower than those estimated under other pathways. However, stranded costs present a risk that might increase costs by 0.37¢ to 1.11¢ per kWh, which could reduce the financial value to customers.

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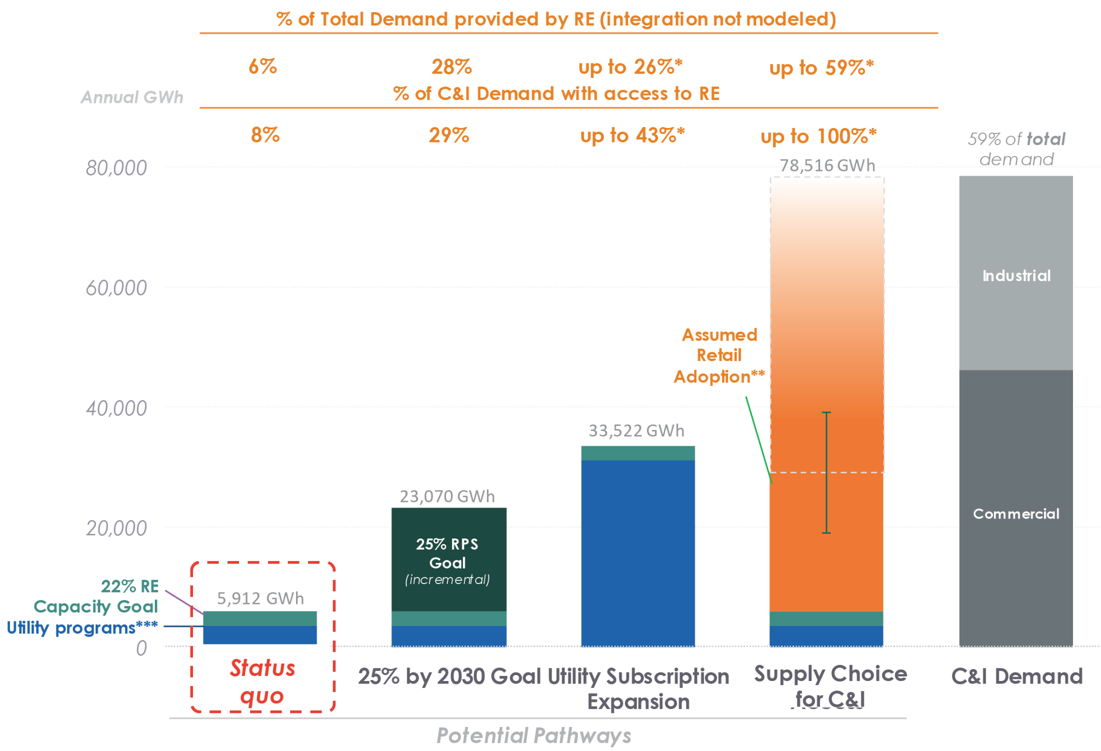
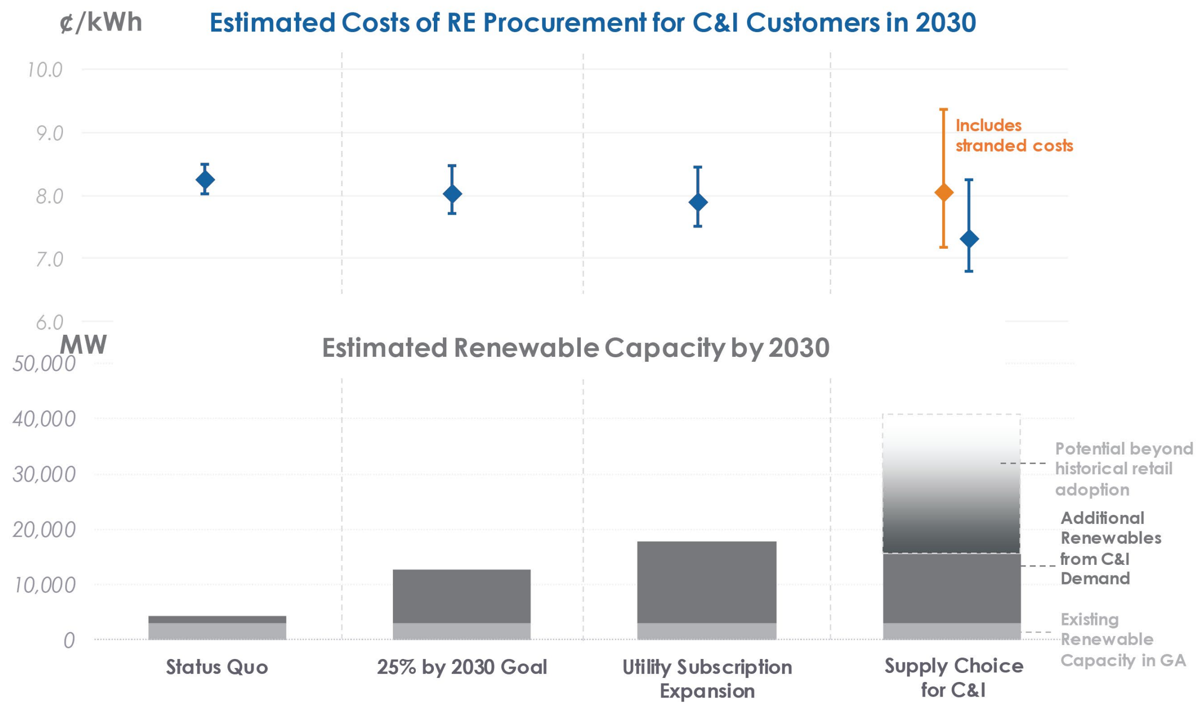
73 Information about resulting pricing from past REDI program procurements is not publicly available. As such, the renewable energy premium is modeled based on known REC prices in the eastern United States. This results in a premium of 0.42¢ per kWh based on REC prices in Virginia.

Figure 13
Georgia: Potential Policy Pathways to Increase C&I Access to Renewable Energy by 2030



Note: While solid orange bar assumes historical adoption, providing supply choice to C&I customers has potential to cover all C&I customer demand. % of Total Demand and % of C&I Demand provided by RE estimates the percentage of total load and C&I load met by renewable energy, respectively. *Subject to customer adoption. **Based on historical C&I adoption rate of 32% (excluding Texas). Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

Figure 14
Georgia: Policy Pathway Estimated Effects



Note: Cost bounds reflect range of projected renewable energy costs and range of possible stranded assets (as applicable). Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

RECAP

Distilling the pathways into reform scenarios, the utility subscription expansion is chosen as the moderate reform scenario and providing supply choice to C&I customers is chosen as the structural reform scenario (Table 18). Given the large amount of potential replacement capacity that could be utilized for expanded C&I subscription programs, the utility subscription expansion provides a near-term opportunity for increasing procurement options without requiring market structure overhauls. This would require working with Georgia Power and state regulators to approve new renewable procurements and tariffs to expand subscription programs. Historically, Georgia Power has provided opportunities to meet C&I demand with the creation of their REDI and CRSP programs. In the long term, supply choice has an opportunity to lower procurement costs given the levelized costs of renewables with additional transmission charges estimated to be below current rates. However, stranded costs present a significant risk that might increase costs by 0.37¢ to 1.11¢ per kWh, which could reduce the value to customers. The adoption potential under this scenario also remains a key uncertainty given the constraint of using historical adoptions rates.

Table 18
Georgia: Progress under Moderate and Structural Policy Pathways

Metrics	Scenarios: Status-Quo 30% Clean Energy Goal is accomplished	Scenarios: Moderate Reform Scenario Utility subscription program capacity is expanded	Scenarios: Structural Reform Scenario Supply Choice is introduced
Additional capacity relative to status-quo	1,260 MW	up to 14,730 MW	12,980 MW to 36,680 MW
Percentage of overall C&I demand with access to RE	8%	up to 43%	37% to 100%
Number of C&I customers with access to RE*	44,800	up to 254,400	221,100 to 595,900
Number of C&I customers with access to 100% RE procurement option**	26,100	up to 235,700	202,300 to 595,900
Estimated Cost of RE Procurement for C&I***	8.03 to 8.50 ¢/kWh	7.51 to 8.44 ¢/kWh	7.17 to 9.36 ¢/kWh
Estimated greenhouse gas reduction from electricity generation	3%	up to 34%	30% to 85%

*Calculation includes RE generation from RPS, utility subscription, and retail providers. **Calculation only includes RE generation from utility subscription and supply choice and excludes generation from RPS. ***Includes stranded assets.

E. Massachusetts

STATE PROFILE

With strong climate policy and full deregulation, Massachusetts already has substantial policies to access and advance the use of renewable energy. Table 19 presents a state profile of Massachusetts highlighting market structure, existing approaches to procure renewable energy for customers, current policy landscape, and a list of the barriers for customers to procure renewable energy.

Table 19
Massachusetts: State Profile

Structural Features	**RTO Participation:** ISO-New England
	Supply Choice: Yes
	State/Utility Goals: • **Mandatory:** State clean energy standard of 40% clean energy by 2030, rising to 80% clean energy by 2050.[74] • **Voluntary:** National Grid's goal is 67% RE by 2030 and 80% RE by 2050.[75] Eversource's goal is 100% by 2030.[76]
Existing RE Procurement Approach	• Procure RE via retailers • Enter into bilateral contracts with renewable suppliers for bundled or unbundled products
Current Policy Landscape	Costs of renewables are high in New England and most long-term contracts for renewables are procured through distribution utilities under state mandates. The state prefers hydro imports and offshore wind resources, with 1.6 GW of offshore wind in development by 2030 and 9.55 TWh of procured hydro imports from Canada. Transmission plans for integrating renewables do not exist, which creates difficulties in producing onshore wind resources that require incremental transmission capabilities. Short-term RECs markets have not been effective in providing revenue certainty to suppliers, despite use of markets by retailers. Utilities options are limited, National Grid's Green Up program provides "green pricing" option.
Barriers	**Supply of RE:** With a centrally organized wholesale market, RE supply barriers are low (limited to economics of market). However, short-term REC prices are volatile, which often does not provide RE suppliers' adequate revenue certainty to build new resources. Short-term state policies focus on resource type-specific procurement, which may not be the most cost-effective way to decarbonize.
	Availability of RE Products/Contracts: Options are available through retailers or bilateral contracts.
	Ease of Procuring RE Products/Contracts: Bilateral contracts remain limited to customers with large resources to negotiate contracts. For retailers, various offering without very clear standardized contracts makes content of retail products unclear and comparison between retail offerings difficult.
	Cost of RE Products/Contracts: RE resources are relatively expensive in New England.

74 "Massachusetts Comprehensive Energy Plan," Massachusetts Department of Energy Resources, December 12, 2018, accessed January 21, 2020.

75 "Northeast 80x50 Pathway," National Grid, June 2018, accessed January 21, 2020.

76 "Eversource's Commitment to Environmental Sustainability and Carbon Neutrality," Eversource, accessed January 21, 2020.

In 2008, Massachusetts enacted the Global Warming Solutions Act (GWSA), which set a statutory goal to reduce emissions by 80 percent below 1990 levels by 2050.[77] In response to the GWSA, the Department of Environmental Protection (DEP) passed the Clean Energy Standard (CES). Beginning in 2018, the CES sets a minimum percentage of electricity sales that utilities and competitive retail suppliers must procure from clean energy sources. The minimum percentage begins at 16 percent in 2018 and increases two percent annually to 80 percent in 2050.[78]

A third of Massachusetts' in-state generation is provided by natural gas (Figure 15).[79] In addition, the region imports a significant amount of hydropower from Québec and recently signed a contract for 9.55 TWh per year of imports from Hydro-Québec, equivalent to roughly a fifth of state demand.[80] To meet its emission and energy targets, Massachusetts plans to procure 3,200 MW of offshore wind by 2035.[81]

77 "Global Warming Solutions Act Background," Massachusetts State Government, accessed January 7, 2020.

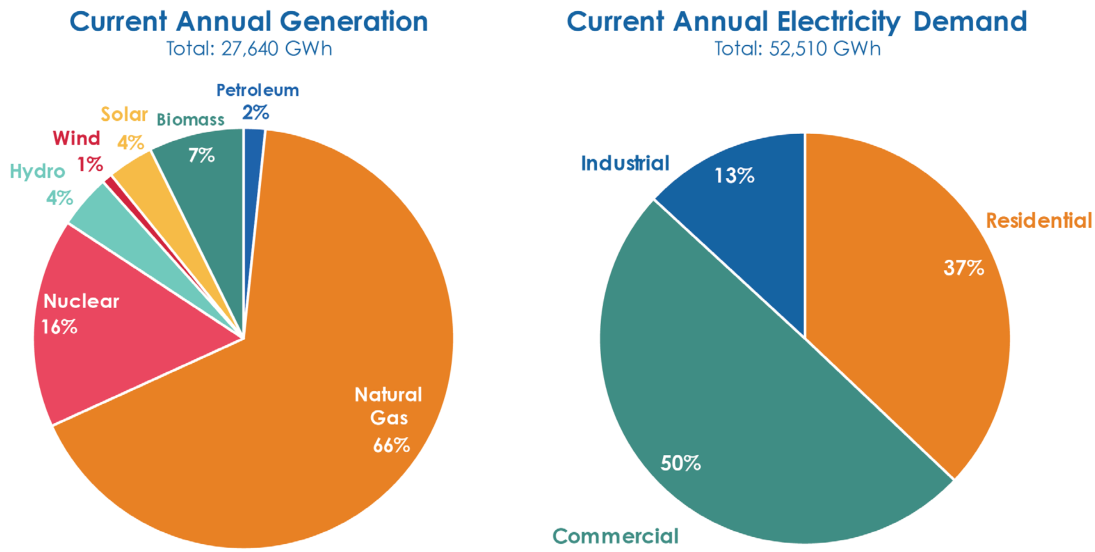
78 "Program Summaries," Massachusetts State Government, accessed January 7, 2020.

79 1,100 MW of renewable energy was installed in Massachusetts by 2018. New England imported 13.9 TWh of hydro from Quebec in 2018, part of which was delivered into Massachusetts. The weighted average C&I retail cost was 16.3¢ per kWh ($163/MWh) in 2018.

80 "Petitions for Approval of Proposed Long-Term Contracts for Renewable Resources Pursuant to Section 83D of Chapter 188 of the Acts of 2016, DPU 18-64, 18-65, 18-66." Department of Energy Resources. July 23, 2018.

81 "Mass. to double offshore wind procurements" – CommonWealth. May 31, 2019.

Figure 15
Massachusetts: 2018 Annual in-State Electricity Generation and Demand



Note: Source: EIA (2018). Transportation demand accounts for <0.7% of total electricity demand, and therefore excluded in this figure. New England imported 13.9 TWh of hydro from Quebec in 2018, not included in this figure.

Massachusetts is a fully deregulated state and participates in an organized wholesale market with full retail choice. C&I customers may procure long-term contracts for renewables both through PPAs and through retail suppliers. However, natural renewable resources in Massachusetts are lower quality than many states except for offshore wind with high, yet declining capital costs.[82] Many retail renewable programs exist; however, little is publicly available about the adoption rates and the pricing components of retail products.

POLICY PATHWAYS

Policy pathways analyzed in Massachusetts are provided in Table 20. These include RPS Expansion to 50 percent and Enhanced Retail Choice for C&I Customers. The latter is a new pathway and only used in Massachusetts. Its purpose is to investigate a scenario where retailers offered renewable contracts priced at the levelized costs of new renewable energy, rather than the average retail rate plus a REC premium.

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82 The forecasted average levelized cost ranges from $31 to $50 per MWh of solar energy, and from $46 to $64 per MWh for offshore wind in the 2020 to 2030 timeframe.

Table 20
Massachusetts Pathway Assumptions and Takeaways

Pathways for 2030	Assumptions	Takeaways for RE Buyer
Status Quo	• Current 40% clean energy standard is met • Utility subscription programs limited given retail choice options in state • Retail adoption is based on state C&I adoption and assumption that 30% of retail sales are for renewable energy • Retail renewable energy provided by procuring RECs	• A portion of grid electricity is provided by renewable energy • Options for buyers seeking additional renewable energy are PPAs and retail provider options • Retail providers renewable procurement based on REC procurement
RPS Expansion	• Clean energy standard expanded to 50% by 2030 • Utility subscription programs remain unchanged	• A larger share of average grid electricity is provided by renewable energy • Options for buyers remain limited to utility subscription programs and PPAs
Enhanced Retail Choice	• Retail providers price the energy component of a contract at the levelized cost of new renewable energy, rather the retail rate plus a REC procurement • Assumption that now 50% of retail sales are for renewable energy • Assumes perfect procurement of RE to meet customer load (no storage or backup generation costs)	• Retail providers procure renewables, not only RECs, to provide low-cost renewable option to customers • Large portion of renewable energy still provided by grid

Note: Utility Subscription Expansion is not considered given that the state already has retail choice.

Applying the three policy pathways to Massachusetts, Figure 16 and Figure 17 present the clean energy generation potential, capacity, and costs for each pathway. Results indicate that, in 2030:

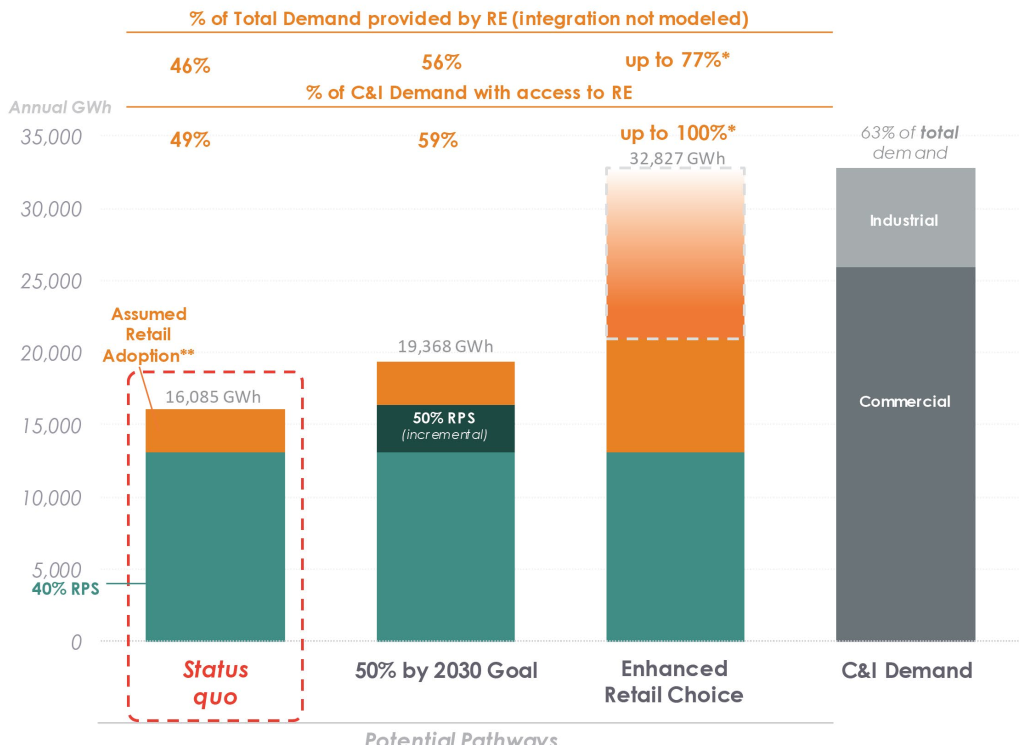
- **Status Quo** will result in 49 percent of C&I customer demand with access to clean energy and 6,634 MW of new renewable capacity to meet C&I customer demand for renewables, primarily through grid average clean energy deliveries by the current RPS. The cost of 100 percent energy procurement through the current utility subscription program (subject to availability) is estimated to be 18.21¢ to 20.92¢ per kWh, which includes the subscription premium.[83]

[83] The renewable energy procurement premium is modeled on Massachusetts resulting in a premium of 2.0¢ per kWh based on average values of Class I RECs.

- **Expanded RPS** increases the share of C&I customer demand with access to clean energy to 59 percent, providing up to 9,006 MW of new renewable capacity to meet C&I customer demand for renewables. This reduces subscription procurement costs to 18.16¢ to 20.92¢ per kWh indirectly, as the energy cost in the standard retail rate declines as more renewables are added to the grid.

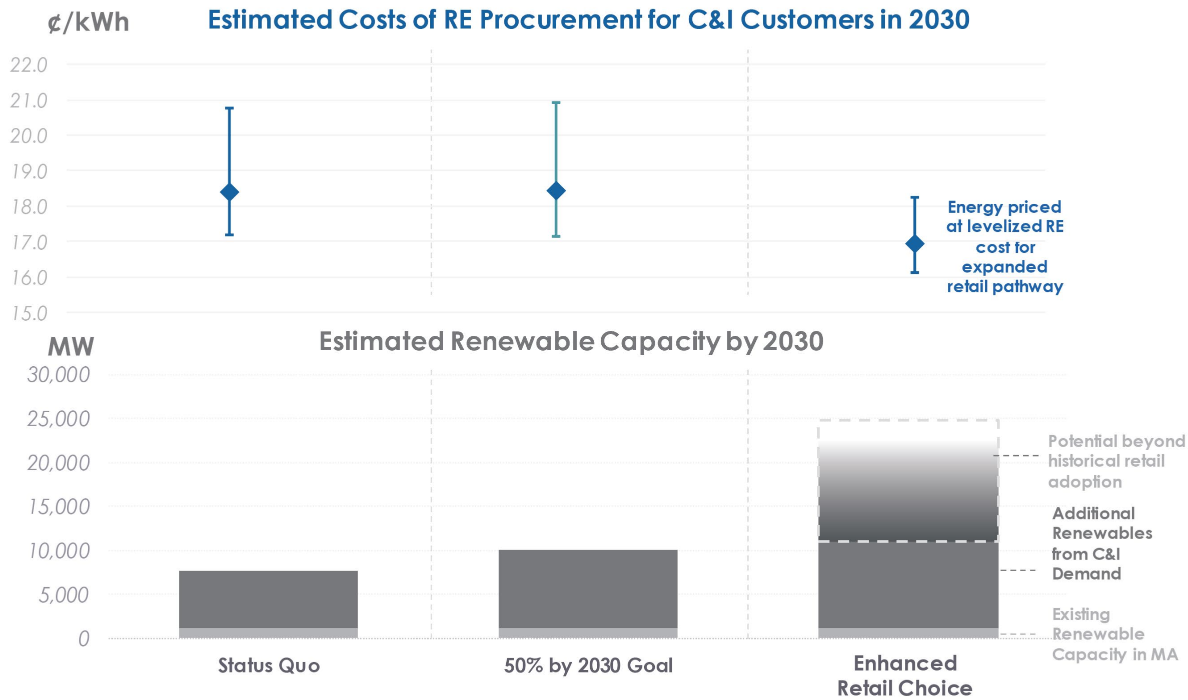
- **Enhanced Retail Choice** provides a pathway where retail products are priced at the levelized cost of renewable energy, plus a retailer premium and the standard utility transmission and distribution charges. As in many other states, supply choice has a theoretical potential to supply all C&I customers. However, it is dependent both on the retail offerings and customer demand. The costs of delivery for such a renewable retail product is estimated to be 16.13¢ to 18.28¢ per kWh, significantly lower than those estimated under other pathways. Since the state has been deregulated fully and all of the generation are subject to the forces of competitive wholesale market, we do not consider any potential stranded costs for Massachusetts. The adoption potential under this scenario also remains a key uncertainty given the constraint of using historical adoptions rates.

Figure 16
Massachusetts: Potential Policy Pathways to Increase C&I Access to Renewable Energy by 2030



Note: While the solid orange bar shows historical adoption, enhanced retail choice has the potential to cover all C&I customer demand. % of Total Demand and % of C&I Demand provided by RE estimates the percentage of total load and C&I load met by renewable energy, respectively. *Subject to customer adoption. **Based on historical C&I adoption rate of 50%, assuming 60% of this is for renewable products. Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

Figure 17
Massachusetts: Policy Pathway Estimated Effects



Note: Cost bounds reflect range of projected RE costs. Capacity additions include capacity of hydro imports from 83D procurement. Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents. Existing renewable capacity does not include any renewable capacity from retailers. Status quo includes C&I capacity share of 1,600 MW OSW procurement.

RECAP

Given Massachusetts strong climate policies and being a deregulated state, most C&I customers will have clean energy supply in the future by default, but options for C&I customers in the state are generally costly and do not promote significant C&I procurement. Distilling the pathways into reform scenarios, the Expanded RPS is selected as the moderate reform scenario and Enhanced Retail Choice is chosen to represent increasing supply options for C&I customers with lower costs under the current structure – no structural change (Table 21). The most promising pathway in Massachusetts would be to work with retail providers to lower procurement costs given the levelized costs of renewables with additional transmission charges are estimated to be below current rates. These efforts should also include the creation of volume-firming agreements (discussed in Appendix B), which could provide around the clock renewable supply at long-term procurement costs.

Table 21
Massachusetts: Progress under Moderate and Structural Policy Pathways

Metrics	Scenarios		
	Status-Quo 40% Clean Energy Goal is accomplished	**Moderate Reform Scenario** Expanded 50% Energy Goal is accomplished	**Moderate Reform Scenario 2** Retail offering price reduced and adoption increases
Additional capacity relative to status-quo	6,630 MW	9,000 MW	9,900 MW to 17,700 MW
Percentage of overall C&I demand with access to RE	49%	59%	64% to 100%
Number of C&I customers with access to RE*	205,800	247,800	256,200 to 420,000
Number of C&I customers with access to 100% RE procurement option**	37,800	37,800	88,200 to 420,000
Estimated Cost of RE Procurement for C&I***	18.21 to 20.78 ¢/kWh	18.16 to 20.92 ¢/kWh	16.13 to 18.28 ¢/kWh
Estimated greenhouse gas reduction from electricity generation	21%	29%	33% to 60%

*Calculation includes RE generation from RPS, utility subscription, and retail providers. **Calculation only includes RE generation from utility subscription and increasing supply choice for C&I customers and excludes generation from RPS. ***Includes stranded assets.

F. Minnesota

STATE PROFILE

Minnesota is part of the MISO wholesale market but lacks supply choice, limiting customer procurement options to PPAs and offerings of their utilities and cooperatives. Table 22 presents a state-profile of Minnesota highlighting the current market structure, existing approaches to procure renewable energy for customers, the current policy landscape, and a list of the barriers for customers to procure renewable energy.

Table 22
Minnesota State Profile

Structural Features	**RTO Participation:** MidContinent Independent System Operator (MISO)
	Supply Choice: No
	State/Utility Goals: • **Mandatory:** 31.5% by 2020 for Excel Energy, 26.5% by 2025 for all other IOUs, 25% by 2025 for all other utilities.[84] *(Averaged to 27% for analysis).* • **Voluntary:** Xcel energy has a goal of 100% carbon free energy by 2050.[85] State aspirational goal set by the governor of 100% clean electricity by 2050.[86]
Existing RE Procurement Approach	• Procure RE through Xcel green power program • Procure RE through PPA • Unbundled REC products
Current Policy Landscape	Minnesota customer RE procurement options include utility and co-op offerings and corporate VPPAs within MISO. Xcel has offered a couple of RE products to commercial customers through their Windsource and Renewable Connect programs, the latter of which is fully subscribed. In August 2019, the utility received approval to expand Renewable Connect beyond its pilot phase and merge Windsource into one central green subscription program.[87]. Recently, the governor unveiled a roadmap of the state's path to clean electricity by 2050.
Barriers	**Supply of RE:** With the centrally organized wholesale market, RE supply barriers are low (limited to economics of market).
	Availability of RE Products/Contracts: In Xcel territory, the Renewable Connect program is relatively available for all customers but is limited to Xcel RE purchases.
	Ease of Procuring RE Products/Contracts: Xcel Renewable Connect has a relatively high ease of procurement.
	Cost of RE Products/Contracts: Xcel's Renewable Connect has a relatively low price, but lack of transparency and a REC market likely prevents driving down REC costs further. As of now, some C&I customers have not found the cost of this program to be competitive.

84 "Minnesota Renewable Energy Update," Minnesota Commerce Department, November 2018, accessed January 21, 2020.

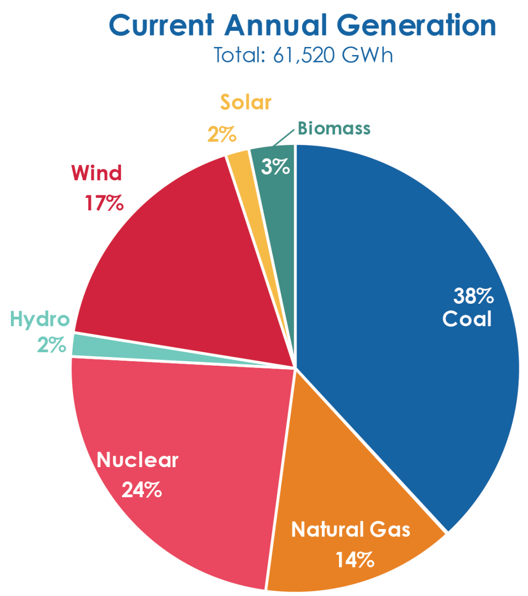
85 "Your Clean Energy Future," Xcel Energy.

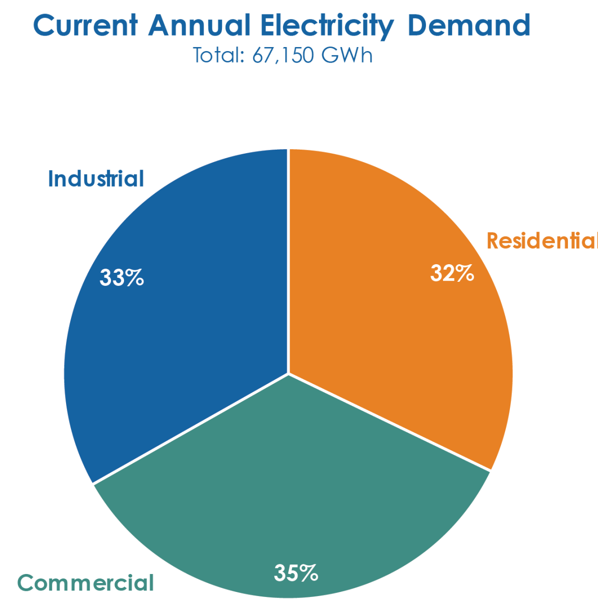
86 "Walz, Flanagan propose plan to achieve 100 percent clean energy in Minnesota by 2050," Minnesota Commerce Department, March 4, 2019, accessed January 21, 2020.

87 "Order Approving Petition with Modifications," Minnesota Public Utilities Commission. August 12, 2019.

Roughly a quarter of all electricity generated in Minnesota is from renewable resources (Figure 18).[88] Minnesota's RPS has requirements of 31.5 percent by 2020 for Xcel Energy; 26.5 percent by 2025 for investor-owned utilities (IOUs); and 25 percent by 2025 for other utilities.[89] In March 2019, Governor Tim Walz unveiled a roadmap to go beyond the RPS for the state to achieve 100 percent renewable electricity by 2050.[90] Xcel Energy, the state's largest utility, has a goal of 100 percent clean energy by 2050 and plans to produce 40 percent of its electricity from renewable resources by 2030.[91, 92]

Figure 18
Minnesota: 2018 Annual in-State Electricity Generation and Demand





Note: Source: EIA (2018). Transportation demand accounts for <0.4% of total electricity demand, and therefore excluded in this figure.

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88 4,700 MW of renewable energy, including hydropower, was installed in Minnesota by 2018. The weighted average C&I retail cost was 9.1¢ per kWh ($91/MWh) in 2018.

89 "Solar Research: Minnesota," National Renewable Energy Laboratory, accessed January 7, 2020.

90 Nick Visser, "Minnesota Governor Wants State Electricity Grid To Go 100 Percent Renewable By 2050," Huffington Post, March 5, 2019.

91 Minnesota Commerce Department, 2018.

92 The forecasted average levelized cost ranges from $27 to $44 per MWh of solar energy, and $29 to $35 per MWh for wind in the 2020 to 2030 time frame.

In Minnesota, customer options to procure renewable energy are limited to corporate PPAs and utility offerings. Xcel Minnesota currently has two renewable subscription programs. Xcel Renewable*Connect offers generation from a specific renewable project and the first resource tranche was fully subscribed. Xcel Windsource continues to provide wind power from utility procurements on month-to-month contracts and charges a modest premium.[93] In 2021, existing Windsource customers will be transitioned into the Renewable Connect program.[94] Xcel Minnesota has also catered to large C&I customer new load needs in the past by offering one-off contracts, such as the recent deal to supply a Google data center with wind energy.[95]

Xcel also offers the Certified Renewable Percentage which allows customers to count the renewable portion of electricity delivered to the customers through Xcel's regular energy mix towards the customer's corporate goals.[96]

POLICY PATHWAYS

Policy pathways analyzed in Minnesota are provided in Table 23. These include Utility Subscription Expansion, RPS Expansion to 40 percent, and Introduction of Supply Choice for C&I Customers.

93 "Windsource for Businesses - Pricing Terms and Conditions," Xcel Energy, accessed January 7, 2020.

94 See August 2019 PUC Order in Docket 19-33.

95 Mark Reilly, "Google, Xcel get Minnesota OK for wind-powered data center," Minneapolis Business Journal, May 15, 2019.

96 Certified Renewable Percentage, Xcel Energy.

Table 23
Minnesota: Pathway Assumptions and Takeaways

Pathways for 2030	Assumptions	Takeaways for RE Buyer
Status Quo	• Current 27% RPS is met. • Utility subscription programs reflects Xcel Windsource subscription data	• A portion of grid electricity is provided by renewable energy • Options for buyers seeking additional renewable energy remain limited to utility subscription programs and PPAs
Utility Subscription Expansion	• Utility subscription programs are expanded with renewable development • RE amount for program expansion estimated using likely fossil fuel retirement (by age) beyond the new RE needed for current RPS	• Expanded utility program provide incremental options for buyers • Option remain limited to utility subscription programs and PPAs
RPS Expansion	• Minnesota increases RPS to 40% • Utility subscription programs remain unchanged	• A larger share of average grid electricity is provided by renewable energy • Options for buyers remain limited to utility subscription programs and PPAs
Supply Choice for C&I Customers	• Supply choice for C&I customers is introduced • Average historical adoption of retail choice assumed, based on U.S. retail adoption data • RE supply provided by new renewables • Assumes perfect procurement of RE to meet customer load (no storage or backup generation costs) • Stranded assets are considered	• Options for buyers seeking additional renewable energy expand to competitive retail providers • Stranded assets add costs • Scalable to all C&I customers

Note: Utility Subscription Expansion 2 is not considered given the amount of assumed generation that would retire to allow for a utility subscription expansion is larger than the amount assumed to provide supply choice to C&I customers.

Applying the three policy pathways to Minnesota, Figure 19 and Figure 20 present the clean energy generation potential, capacity, and costs for each pathway. Results indicate that, in 2030:

- **Status Quo** will result in 30 percent of C&I customer demand with access to clean energy and 1,053 MW of new renewable capacity to meet C&I customer demand for renewables, primarily through grid average clean energy deliveries by the current RPS. The cost of 100 percent energy procurement through the current utility subscription program (subject to availability) is estimated to be 10.30¢ to 11.5¢ per kWh, which includes the subscription premium.[97, 98]

[97] "Renewable*Connect," Xcel Energy.

[98] The renewable energy premium is modeled based on the monthly Xcel Renewable*Connect premium, with a premium of 1.2¢ per kWh.

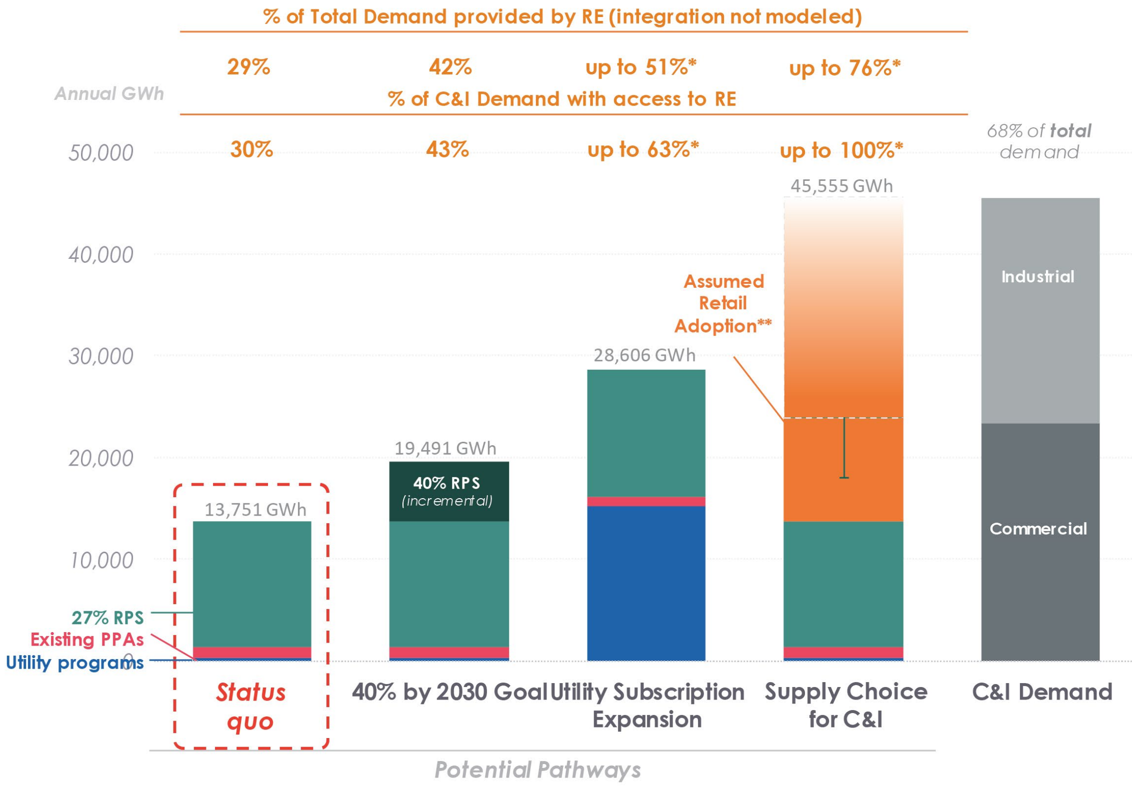
- **Expanded RPS** increases the share of C&I customer demand with access to clean energy to 43 percent, providing up to 3,035 MW of new renewable capacity to meet C&I customer demand for renewables. This reduces subscription procurement costs to ¢10.32 to 11.61¢ per kWh indirectly, as the energy cost in the standard retail rate declines as more renewables are added to the grid.

- **Utility Subscription Expansion** pathway implies a large renewable potential in Minnesota, due to the sheer size of fossil generation capacity likely to retire by 2030. Along with the current RPS, this pathway has the potential to cover up to 63 percent of C&I customer demand and increase new state renewable energy capacity to 6,184 MW to meet C&I customer demand for renewables. This pathway reduces subscription procurement costs to 10.35¢ to 11.78¢ per kWh indirectly, as the energy cost in the standard retail rate declines further as more renewables are added to the grid.

- **Providing Supply Choice to C&I Customers**, as in many other states, has a theoretical potential to supply all C&I customer demand. However, it is dependent both on the retail offerings and customer demand. Without stranded costs, the costs of delivery for a renewable retail product is estimated to be 9.59¢ to 10.37¢ per kWh, lower than those estimated under other pathways. However, stranded costs present a risk that might increase costs by 0.44¢ to 1.32¢ per kWh, which could reduce the financial value to customers.

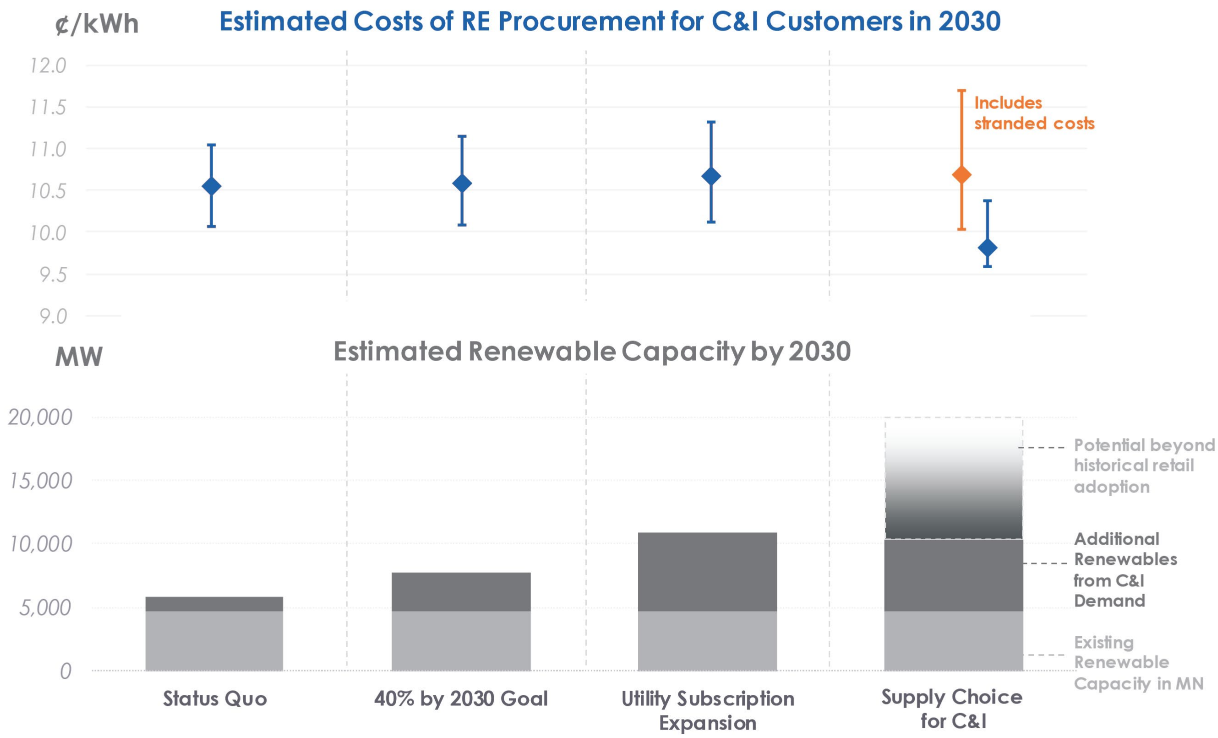
Figure 19

Minnesota: Potential Policy Pathways to Increase C&I Access to Renewable Energy by 2030



Note: While the solid orange bar shows historical adoption, providing supply choice to C&I customers has the potential to cover all C&I customer demand. % of Total Demand and % of C&I Demand provided by RE estimates the percentage of total load and C&I load met by renewable energy, respectively. *Subject to customer adoption. **Based on historical C&I adoption rate of 32% (excluding Texas). Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

Figure 20
Minnesota: Policy Pathway Estimated Effects



Note: Cost bounds reflect range of projected renewable energy costs and range of possible stranded assets (as applicable). Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

RECAP

Distilling the pathways into reform scenarios, the utility subscription expansion is chosen as the moderate reform scenario and providing supply choice to C&I customers is chosen as the structural reform scenario (Table 24). Given the large amount of potential replacement capacity that could be utilized for expanded C&I subscription programs, the utility subscription expansion provides a near-term opportunity for increasing procurement options without requiring market structure overhauls. This would require working with Xcel and state regulators to approve new renewable procurements and tariffs to expand subscription programs. In the long term, providing supply choice to C&I customers has an opportunity to lower procurement costs given the levelized costs of renewables, with additional transmission charges, are estimated to be below current rates. However, stranded costs present a significant risk that might increase costs by 0.44¢ to 1.32¢ per kWh, which could reduce the financial value to customers.

Table 24
Minnesota: Progress under Moderate and Structural Policy Pathways

	Scenarios		
	Status-Quo	**Moderate Reform Scenario**	**Structural Reform Scenario**
Metrics	27% Clean Energy Goal is accomplished	Utility subscription program capacity is expanded	Supply Choice for C&I is introduced
Additional capacity relative to status-quo	910 MW	up to 6,250 MW	5,380 MW and 14,140 MW
Percentage of overall C&I demand with access to RE	29%	up to 63%	52% to 100%
Number of C&I customers with access to RE*	91,100	up to 189,500	158,500 to 301,800
Number of C&I customers with access to 100% RE procurement option**	8,400	up to 106,800	75,800 to 301,800
Estimated Cost of RE Procurement for C&I***	10.07 to 11.04 ¢/kWh	10.12 to 11.32 ¢/kWh	9.84 to 12.41 ¢/kWh
Estimated greenhouse gas reduction from electricity generation	5%	up to 37%	32% to 84%

*Calculation includes RE generation from RPS, utility subscription, and retail providers. **Calculation only includes RE generation from utility subscription and supply choice and excludes generation from RPS. ***Includes stranded assets.

G. North Carolina

STATE PROFILE

With no centrally organized wholesale market and no supply choice in North Carolina, incumbent utility Duke Energy controls the current energy procurement for customers. Table 25 presents a state profile of North Carolina highlighting market structure, existing approaches to procure renewable energy for customers, the current policy landscape, and a list of the barriers for customers to procure renewable energy.

Table 25
North Carolina: State Profile

<table>
<tr><td rowspan="3">Structural Features</td><td>RTO Participation: No (small portion in PJM)</td></tr>
<tr><td>Supply Choice: No</td></tr>
<tr><td>State/Utility Goals:
• Mandatory: State RPS Requirement is 12.5% RE by 2021 for IOUs.[99]
• Voluntary: Aspirational state clean energy plan to reduce emissions to 70% below 2005 levels by 2030.[100] Duke Energy goal of net zero carbon emissions by 2050.[101]</td></tr>
<tr><td>Existing RE Procurement Approach</td><td>• Procure RE through corporate PPAs (in small PJM territory)
• Procure RE through Duke Energy sleeve contracts (Green Source Advantage Program) or shared solar program</td></tr>
<tr><td>Current Policy Landscape</td><td>The lack of RTO participation in most of the state and absence of supply choice limits most North Carolina customers to utility RE programs. North Carolina also lacks any mechanism to procure RE except for the utility IRP process and PURPA. While Duke Energy does offer some RE programs, such as the Green Source Advantage Program, they require substantial investments of time and effort to negotiate contracts with developers.</td></tr>
<tr><td rowspan="4">Barriers</td><td>Supply of RE: Lack of organized wholesale market limits RE supply to utility IRP and PURPA facilities.</td></tr>
<tr><td>Availability of RE Products/Contracts: RE is limited to utility sleeve contracts, which are also limited to 250 MW in total.</td></tr>
<tr><td>Ease of Procuring RE Products/Contracts: The current utility program requires significant effort and information requirements.</td></tr>
<tr><td>Cost of RE Products/Contracts: Without a transparent centralized REC market to drive prices down, prices will remain determined by negotiations in sleeve contracts. In addition, Duke sleeve contracts have additional administrative fees that could be prohibitive.</td></tr>
</table>

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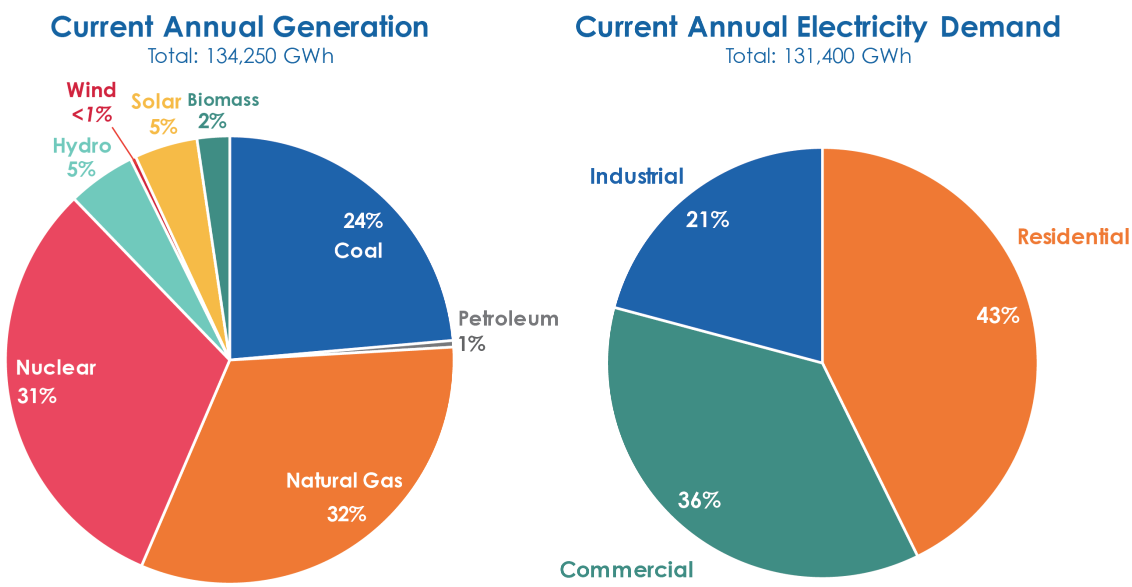
99 "Renewable Energy and Energy Efficiency Portfolio Standard (REPS)," North Carolina Utilities Commission (NCUC), accessed January 21, 2020.

100 "North Carolina Clean Energy Plan," North Carolina Department of Environmental Quality (NCDEQ), October 2019, accessed January 21, 2020.

101 "Duke Energy aims to achieve net-zero carbon emissions by 2050," Duke Energy, September 17, 2019, accessed January 21, 2020.

Over half of North Carolina's energy is generated from fossil resources, and nuclear makes up the majority of the rest (Figure 21).[102, 103] In 2007, North Carolina passed its current RPS is 12.5 percent by 2021, which it has already met. In addition, the state has an aspirational goal of reducing emissions to 70 percent below 2005 levels as part of its 2019 Clean Energy Plan.[104] Duke Energy also has an aspirational corporate goal of net zero carbon emissions by 2050. In 2019, the state's electricity commission accepted Duke's integrated resource plan but also ordered the utility to consider coal retirement, large emission reductions, and battery storage in its upcoming post-2020 planning.[105]

Figure 21
North Carolina: 2018 Annual in-State Electricity Generation and Demand



Notes: Source: EIA (2018). Transportation demand accounts for <0.1% of total electricity demand, and therefore excluded in this figure.

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102 6,100 MW of renewable energy, including hydropower, was installed in North Carolina by 2018. The weighted average C&I retail cost was 7.8¢ per kWh ($78/MWh) in 2018.

103 The forecasted average levelized cost ranges from $22 to $36 per MWh of solar energy, and from $51 to $71 per MWh for wind in the 2020 to 2030 timeframe.

104 NCDEQ, 2019.

105 Christian Roselund, "North Carolina regulators reject the dirty assumptions in Duke's latest plan," PV Magazine, August 29, 2019.

Offerings of electric supply in the state are limited to Duke's utility offerings. In 2017, the state passed the Competitive Energy Solutions Law, which mandated the creation of a Green Source Rider Program that allows large utility customers to offset their electricity usage with renewable energy.[106] In response, Duke Energy Progress developed its Green Source Advantage (GSA) program, a sleeve program for customers with a demand greater than 1 MW (or 5 MW aggregated) limited to 250 MW for C&I customers.[107] This program remains limited to very large-scale buyers with a sufficiently large load and the resources to pay the application and administrative fees.

POLICY PATHWAYS

The policy pathways analyzed for North Carolina are provided in Table 26. These include Utility Subscription Expansion, RPS Expansion to 30 percent, and Introduction of Supply Choice to C&I Customers.

Table 26
North Carolina: Pathway Assumptions and Takeaways

Pathways for 2030	Assumptions	Takeaways for RE Buyer
Status Quo	• Current 12.5% RPS is met. • Utility subscription programs reflects Duke Green Source Advantage program capacity	• A portion of grid electricity is provided by renewable energy • Options for buyers seeking additional renewable energy remain limited to utility subscription programs and PPAs
Utility Subscription Expansion	• Utility subscription programs are expanded with renewable development • RE amount for program expansion estimated using likely fossil fuel retirement (by age) beyond the new RE needed for current RPS	• Expanded utility program provide incremental options for buyers • Option remain limited to utility subscription programs and PPAs
RPS Expansion	• North Carolina increases RPS to 30% • Utility subscription programs remain unchanged	• A larger share of average grid electricity is provided by renewable energy • Options for buyers remain limited to utility subscription programs and PPAs
Supply Choice for C&I Customers	• Supply choice for C&I customers is introduced • Average historical adoption of retail choice assumed, based on U.S. retail adoption data • RE supply provided by new renewables • Assumes perfect procurement of RE to meet customer load (no storage or backup generation costs) • Stranded assets are considered	• Options for buyers seeking additional renewable energy expand to competitive retail providers • Stranded assets add costs • Scalable to all C&I customers

Note: Utility Subscription Expansion 2 is not considered given the amount of assumed generation that would retire to allow for a utility subscription expansion is larger than the amount assumed to provide supply choice to C&I customers.

106 Jeffery R. Atkin, "N.C. Governor Signs H.B. 589," Foley, August 4, 2017.

107 "Green Source Advantage," Duke Energy Progress, accessed January 10, 2020.

Applying the three policy pathways to North Carolina, Figure 22 and Figure 23 present the clean energy generation potential, capacity, and costs for each pathway. Results indicate that, in 2030:

- **Status Quo** will result in 16 percent of C&I customer demand with access to clean energy and 1,482 MW of new renewable capacity to meet C&I customer demand for renewables, primarily through grid average clean energy deliveries by the current RPS. The cost of 100 percent energy procurement through the current utility subscription program (subject to availability) is estimated to be 7.76¢ to 8.23¢ per kWh, which includes the subscription premium.[108]

- **Expanded RPS** increases the share of C&I customer demand with access to clean energy to 33 percent, providing up to 8,473 MW of new renewable capacity to meet C&I customer demand for renewables. This reduces subscription procurement costs to 7.57¢ to 8.31¢ per kWh indirectly, as the energy cost in the standard retail rate declines as more renewables are added to the grid.

- **Utility Subscription Expansion** pathway implies a large renewable potential in North Carolina, due to the sheer size of fossil generation capacity likely to retire by 2030. Along with the current RPS, the USE pathway has the potential to cover up to 60 percent of C&I customer demand and increase new state renewable energy capacity to 19,377 MW to meet C&I customer demand for renewables. This pathway reduces subscription procurement costs to 7.29¢ to 8.43¢ per kWh indirectly, as the energy cost in the standard retail rate declines further as more renewables are added to the grid.

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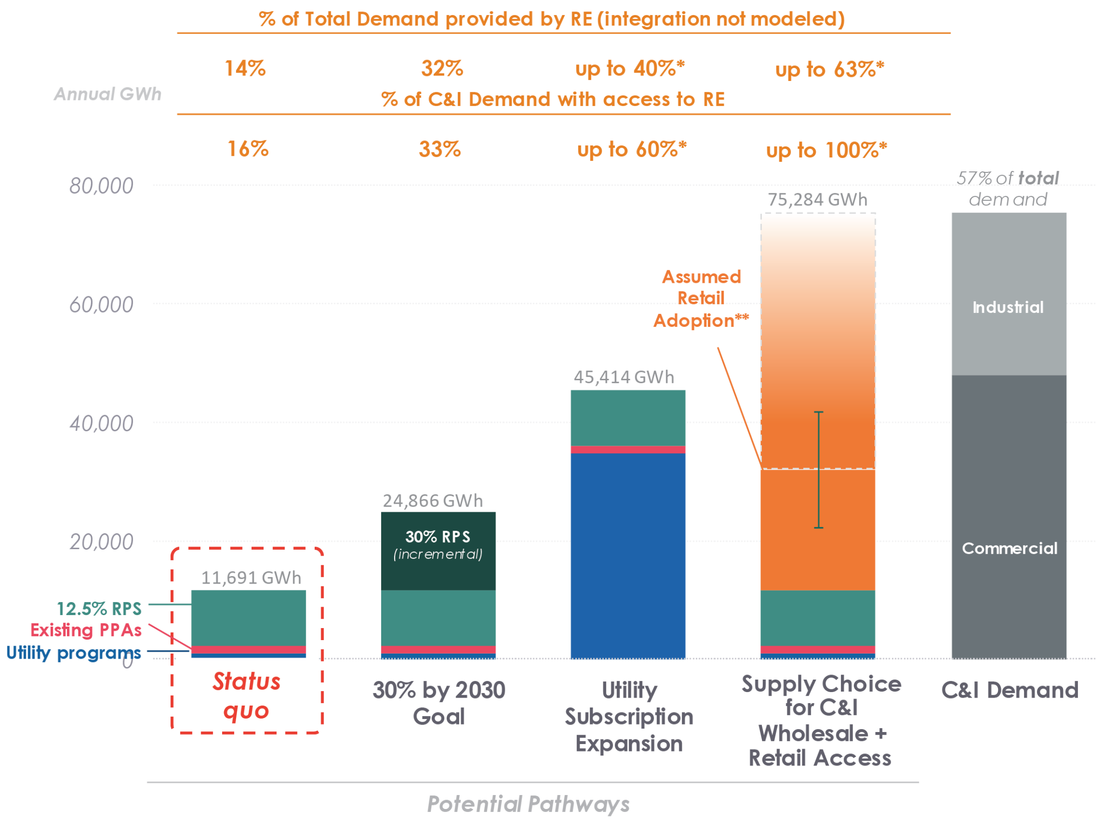
108 Information about resulting pricing from the GSA program are not publicly available. As such, the renewable energy premium is modeled based on known REC prices in the eastern United States, resulting in a premium of 0.42¢ per kilowatt-hour (kWh) based on REC prices in Virginia.

- **Introducing Supply Choice to C&I Customers**, as in many other states, has a theoretical potential to supply all C&I customer demand. However, it is dependent both on the retail offerings and customer demand. Without stranded costs, the costs of delivery for a renewable retail product is estimated to be 7.00¢ to 8.62¢ per kWh, lower than those estimated under other pathways. However, stranded costs present a risk that might increase costs by 0.55¢ to 1.64¢ per kWh, which could remove the financial value to customers.

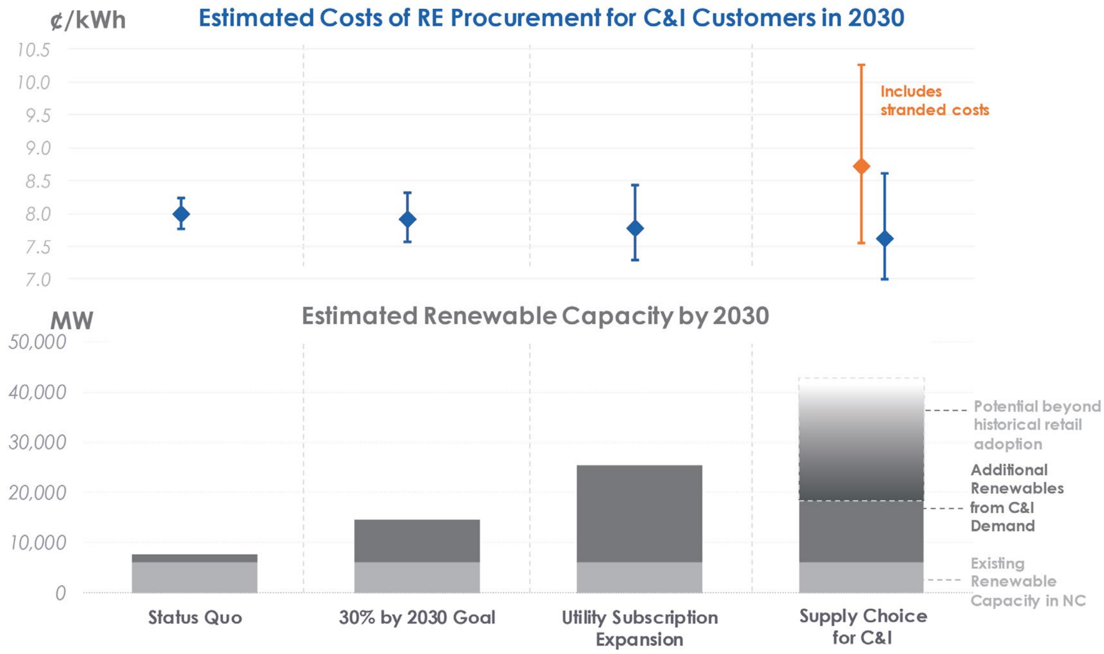
Figure 22

North Carolina: Potential Policy Pathways to Increase C&I Access to Renewable Energy by 2030



Note: While the solid orange bar shows historical adoption, providing C&I customers with supply choice has the potential to cover all of C&I customer demand. % of Total Demand and % of C&I Demand provided by RE estimates the percentage of total load and C&I load met by renewable energy, respectively. *Subject to customer adoption. **Based on historical C&I adoption rate of 32% (excluding Texas). Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

Figure 23
North Carolina: Policy Pathway Estimated Effects



Note: Cost bounds reflect range of projected RE costs and range of possible stranded assets (as applicable). Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

RECAP

With significant amounts of fossil retirements and good solar resources, the expansion of utility subscription programs is selected as the moderate reform scenario and providing supply choice to C&I customers is chosen as the structural reform scenario (Table 27). Given the large amount of potential replacement capacity that could be utilized for expanded C&I subscription programs, that option provides a near-term opportunity for increasing procurement options without requiring market structure overhauls. This would require working with the North Carolina utilities to approve new renewable procurements and tariffs to expand subscription programs. The state's policymakers have indicated a greater need to take into account climate considerations in resource planning, thus, we anticipate that the utilities will increase their engagement in serving C&I customer needs. In the long term, providing supply choice to C&I customers has an opportunity to lower procurement costs given the levelized costs of renewables with additional transmission charges are estimated to be below current rates (Figure 23). However, stranded costs present a risk that would increase costs by 0.55¢ to 1.64¢ per kWh, which could decrease the financial value to customers.

Table 27
North Carolina: Progress under Moderate and Structural Policy Pathways

	Scenarios		
Metrics	**Status-Quo** 12.5% Clean Energy Goal is accomplished	**Moderate Reform Scenario** Utility subscription program capacity is expanded	**Structural Reform Scenario** Supply Choice for C&I is introduced
Additional capacity relative to status-quo	1,480 MW	up to 19,370 MW	12,270 MW and 35,220 MW
Percentage of overall C&I demand with access to RE	16%	up to 60%	43% to 100%
Number of C&I customers with access to RE*	107,300	up to 416,800	294,000 to 691,000
Number of C&I customers with access to 100% RE procurement option**	21,000	up to 330,500	207,600
Estimated Cost of RE Procurement for C&I***	7.76 to 8.23 ¢/kWh	7.57 to 8.31 ¢/kWh	7.55 to 10.26 ¢/kWh
Estimated greenhouse gas reduction from electricity generation	3%	up to 45%	29% to 82%

*Calculation includes RE generation from RPS, utility subscription, and retail providers. **Calculation only includes RE generation from utility subscription and supply choice and excludes generation from RPS. ***Includes stranded assets.

H. Virginia

STATE PROFILE

Virginia is a member of the PJM wholesale market and has partial supply choice for loads greater than 5 MW, although it typically does not allow aggregation to reach this threshold. This leaves customers with corporate PPAs and utility offerings as their main procurement options.

Table 28 presents a state profile of Virginia highlighting market structure, the current approaches to procure renewable energy for customers, the current policy landscape, and a list of the barriers for customers to procure renewable energy.

Table 28
Virginia: State Profile

Structural Features	**RTO Participation:** PJM
	Supply Choice: Partial (loads over 5 MW, minimal aggregation)[109]
	State/Utility Goals: • **Mandatory:** Recent executive order by Governor sets 30% clean electricity target by 2030, and 100% by 2050.[110] • **Voluntary:** Renewable portfolio standard of 15% by 2025. ApCo, as part of AEP, has a 100% by 2050 goal.[111]
Existing Approach Available to Customers	• Enter into bilateral contracts with renewable suppliers for bundled or unbundled products • Procure RE through ApCO utility program (and pending Dominion green tariff)
Current Policy Landscape	Under current Virginia law, retail suppliers can sell 100% renewable power directly to customers if the customer's incumbent utility does not offer a separate 100% renewable tariff or if demand exceeds 5 MW. Aggregation of load to meet this threshold has been very limited. To date, ApCo, has a green tariff and Dominion has one pending. If the latter is approved, retail suppliers will not be allowed to sell similar options in the state. Moreover, the Dominion tariff has received negative feedback from corporate buyers for significant flaws. Outside of utility programs, access to PJM's wholesale market allows customers procure RECs through voluntary purchases. Bilateral voluntary REC purchases are not scalable for suppliers to build new renewable resources.
Barriers	**Supply of RE:** No large barriers, supply is limited to economic development in market
	Availability of RE Products/Contracts: Limited to utility offerings for customers below 5 MW load
	Ease of Procuring RE Products/Contracts: ApCo utility tariff relatively high ease to procure
	Cost of RE Products/Contracts: In the ApCo territory, ApCo's Green Pricing Program premium is relatively high compared to other utility offerings (ApCo). Dominion's tariff design has similar costs.[112]

109 Catherine Morehouse, "Dominion's 100% renewables tariff could kill Virginia's retail choice ambitions," Utility Dive, August 5, 2019.

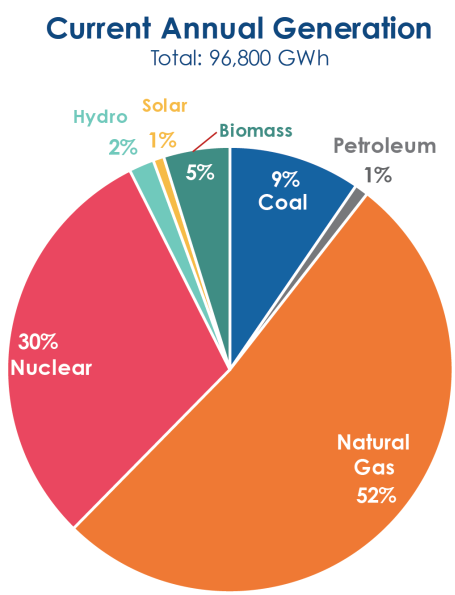
110 "Expanding Access to Clean Energy and Growing the Clean Energy Jobs of the Future," Commonwealth of Virginia Executive Order Number Forty-Three (2019). Issued September 16, 2019.

111 "AEP Accelerates Carbon Dioxide Emissions Reduction Target," American Electric Power, September 10, 2019, accessed January 21, 2020.

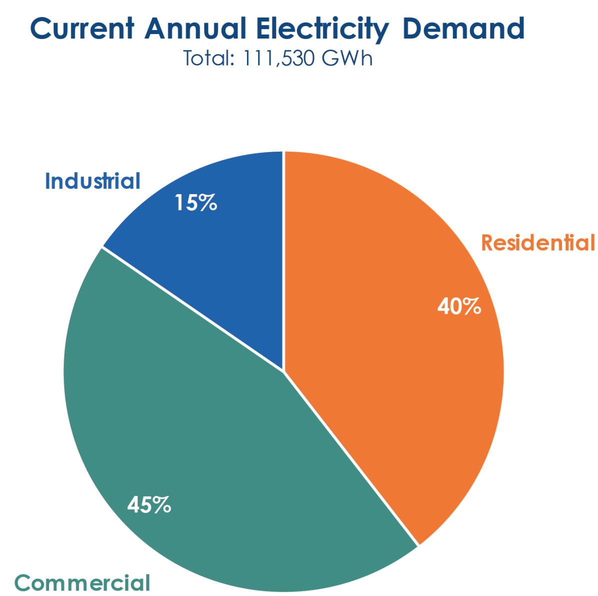
112 "Application of Virginia Electric and Power Company for approval of a 100 percent renewable energy tariff," case number PUR-2019-00094. Filed May 31, 2019.

Over half of in-state generation in Virginia is from fossil, and another third is from nuclear power (Figure 24).[113] In 2010, Virginia passed a 15 percent renewable portfolio standard by 2025. More recently, in September 2019, Governor Northam signed an executive order committing the state to 100 percent clean energy by 2050. Additionally, Appalachian Power Company (ApCo), as part of American Electric Power, is committed to 100 percent clean energy by 2050 and Dominion has announced it will procure 2,600 MW of offshore wind by 2026 off the coast of Virginia. [114, 115]

Figure 24
Virginia: 2018 Annual in-State Electricity Generation and Demand



Source: EIA (2018). Note: Half of current utility green subscription programs are provided by out-of-state resources located in PJM.



Source: EIA (2018). Note: Transportation demand accounts for <0.2% of total electricity demand, and therefore excluded in this figure.

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113 1,280 MW of renewable energy, including hydropower, was installed in Virginia by 2018. The weighted average C&I retail cost was 8.0¢ per kWh ($80/MWh) in 2018.

114 The forecasted average levelized cost ranges from $20 to $31 per MWh of solar energy, and from $61 to $115 per MWh for offshore wind in the 2020 to 2030 timeframe.

115 "Dominion Energy Announces Largest Offshore Wind Project in US," Dominion Energy, September 19, 2019, accessed January 22, 2020.

Distribution in Virginia is largely controlled by the state's two main utilities: ApCo and Dominion. Under current Virginia law, competitive retail suppliers can sell 100 percent renewable power directly to customers if the customer's incumbent utility does not offer a separate 100 percent renewable tariff or if demand for RE exceeds the state's 5 MW supply choice threshold. However, ApCo and Dominion have recently created green tariffs that have reduced the ability of retailers to provide renewable energy to customers. Both tariffs have received negative feedback from corporate buyers for this limitation and other potential areas for debate, such as the costs associated with older renewable resources and the classification of certain power generation facilities that use biomass and coal.

POLICY PATHWAYS

Policy pathways analyzed in Virginia are provided in Table 29. These include RPS Expansion to 30 percent, Introduction of Supply Choice to C&I Customers, and Utility Subscription Expansion.

Table 29
Virginia: Pathway Assumptions and Takeaways

Pathways for 2030	Assumptions	Takeaways for RE Buyer
Status Quo	• Current 15% RPS is met • Utility subscription programs remain unchanged	• A portion of grid electricity is provided by renewable energy • Options for buyers seeking additional renewable energy remain limited to utility subscription programs and PPAs
RPS Expansion	• Expanded 30% RPS is met • Utility subscription programs remain unchanged	• A larger share of average grid electricity is provided by renewable energy • Options for buyers remain limited to utility subscription programs and PPAs
Supply Choice for C&I Customers	• Supply choice for C&I customers is introduced • Average historical adoption of retail choice assumed, based on U.S. retail adoption data • RE supply provided by new renewables • Stranded assets are considered	• Options for buyers seeking additional renewable energy expand to competitive retail providers • Stranded assets add costs • Scalable to all C&I customers
Utility Subscription Expansion 2	• Utility expands subscription programs beyond previous expansion to satisfy C&I demand. • Utility develops more RE than necessary for RPS or to replace retiring fossil • Amount of RE provided is equal to the amount assumed in the supply choice pathway • Stranded assets are considered	• Utility program expands to satisfy more C&I demand • Stranded assets add costs

Note: Utility Subscription Expansion is not considered because the amount of assumed resources for retirement to provide renewable options for C&I customers is less than the necessary buildout of RE to meet the state's clean energy standard. Thus, fulfilling the RPS will provide more RE to customers than if we were to assume that the amount of incremental RE buildout is dependent on candidate fossil generation retirements.

Applying the three policy pathways to Virginia, Figure 25 and Figure 26 present the clean energy generation potential, capacity, and costs for each pathway. Results indicate that, in 2030:

- **Status Quo** will result in 33 percent of C&I customer demand with access to clean energy and 6,950 MW of new renewable capacity (2,600 MW offshore wind) to meet C&I customer demand for renewables, primarily through grid average clean energy deliveries by the current RPS. The cost of 100 percent energy procurement through the current utility subscription program (subject to availability) is estimated to be 7.69¢ to 8.51¢ per kWh, which includes the subscription premium.[116]

- **Expanded RPS** increases the share of C&I customer demand with access to clean energy to 48 percent, providing up to 11,254 MW of new renewable capacity to meet C&I customer demand for renewables. This reduces subscription procurement costs to 7.52¢ to 8.57¢ per kWh indirectly, as the energy cost in the standard retail rate declines as more renewables are added to the grid.

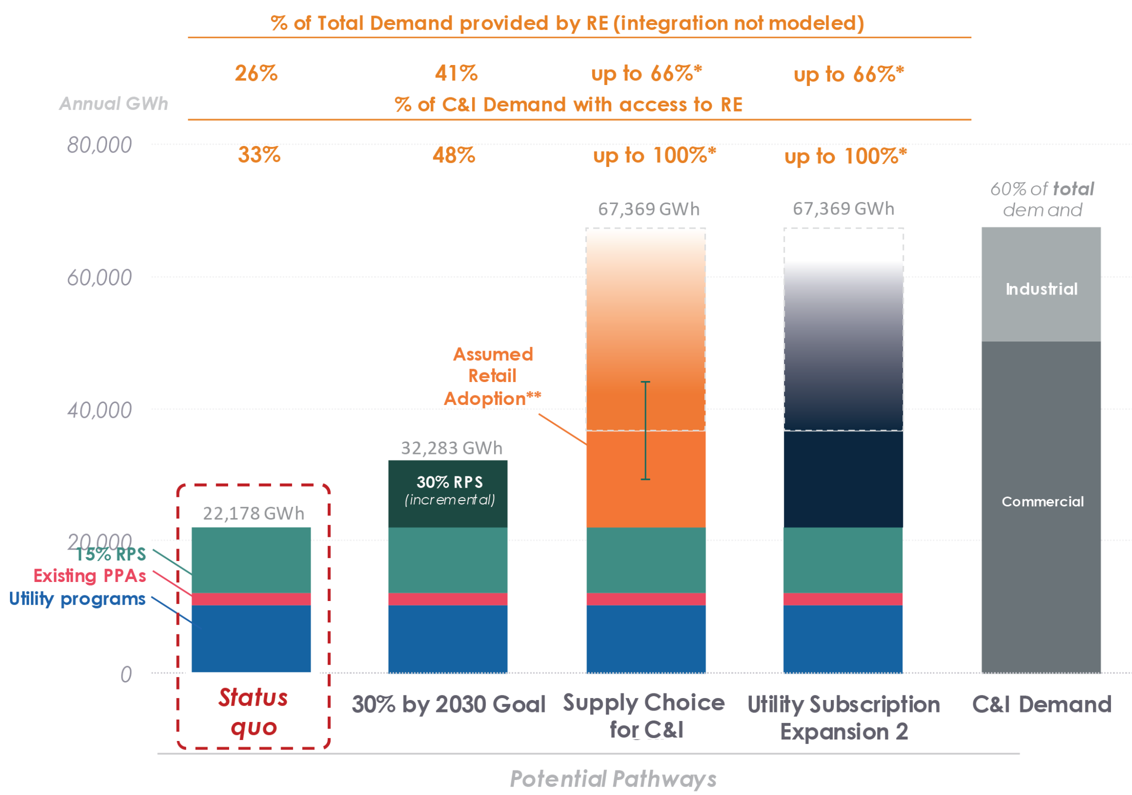
- **Introducing Supply Choice for C&I Customers**, as in many other states, has a theoretical potential to supply all C&I customer demand. However, it is dependent both on the retail offerings and customer demand. Without stranded costs, the costs of delivery for a renewable retail product is estimated to be 7.47¢ to 8.78¢ per kWh, lower than those estimated under other pathways. However, stranded costs present a risk that might increase costs by 0.38¢ to 1.14¢ per kWh, which could reduce the financial value to customers.

116 The renewable energy procurement premium in Virginia is modeled based on the ApcCo and Dominion programs, with an average premium 0.423¢ per kWh and assumed to remain the same for the utility subscription expansion and the RPS expansion.

- **Utility Subscription Expansion 2** pathway expands utility subscription programs to meet all of C&I customer demand, allowing similar access to renewables as the Supply Choice pathway but with the renewables provided by the utility. We assume that only generation to supply subscribing C&I customer demand will be stranded under this pathway, therefore the estimated stranded asset costs are lower under this pathway than under Supply Choice for C&I Customers. However, under this pathway, we assume that the stranded costs would be spread over subscribing C&I customers only. Ultimately, we estimate that the prices for the Utility Subscription Expansion 2 pathway are similar to those under providing supply choice to C&I customers.

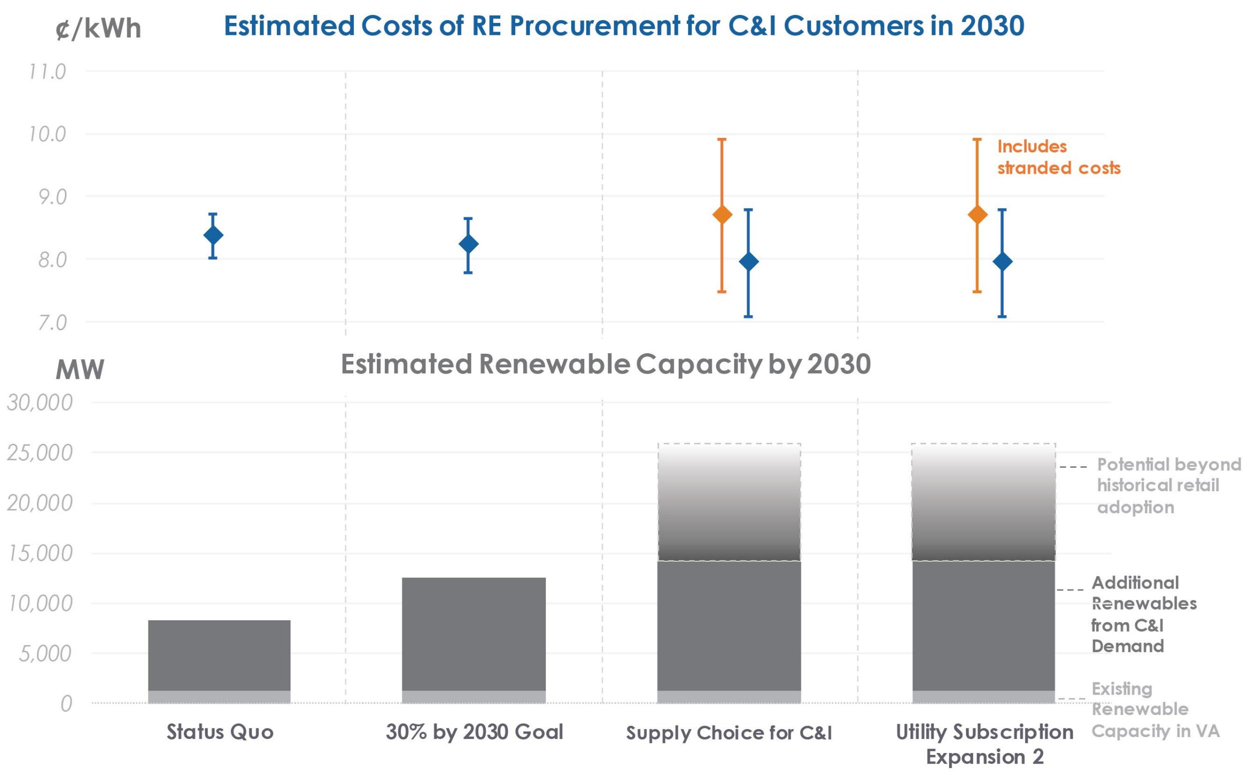
Figure 25

Virginia: Potential Policy Pathways to Increase C&I Access to Renewable Energy by 2030



Note: While the solid orange bar shows historical adoption, providing supply choice to C&I customers has the potential to cover all C&I customer demand. % of Total Demand and % of C&I Demand provided by RE estimates the percentage of total load and C&I load met by renewable energy, respectively. *Subject to customer adoption. **Based on historical C&I adoption rate of 32% (excluding Texas). Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

Figure 26
Virginia: Policy Pathway Estimated Effects



Note: Cost bounds reflect range of projected renewable energy costs and range of possible stranded assets (as applicable). Costs between Supply Choice and Expansion 2 are similar because less stranded costs get spread over a smaller customer base. Source: Brattle analysis of data from EIA, utility tariffs, and state policy documents.

Distilling the pathways into reform scenarios, the Expanded RPS is chosen as the moderate reform scenario and providing supply choice to C&I customers is chosen as the structural reform scenario (Table 30). In the short-term, the moderate reform strategy ensures that the Executive Order signed by the state governor is not overturned by another governor or is passed into law by the state legislation. In the long term, providing supply choice to C&I customers has an opportunity to lower procurement costs given the levelized costs of renewables with additional transmission charges are estimated to be below current rates. However, stranded costs present a risk that might increase costs by 0.38¢ to 1.14¢ per kWh, which could reduce the financial value to customers.

Table 30
Virginia: Progress under Moderate and Structural Policy Pathways

	Scenarios		
Metrics	**Status-Quo** 15% Clean Energy Goal is accomplished	**Moderate Reform Scenario** 30% Clean Energy goal is accomplished	**Structural Reform Scenario** Supply Choice for C&I is introduced
Additional capacity relative to status-quo	6,950 MW	11,250 MW	12,900 MW to 26,000 MW
Percentage of overall C&I demand with access to RE	33%	48%	53% to 100%
Number of C&I customers with access to RE*	140,200	204,100	231,600 to 426,000
Number of C&I customers with access to 100% RE procurement option**	76,300	76,300	167,700 to 426,000
Estimated Cost of RE Procurement for C&I***	7.69 to 8.51 ¢/kWh	7.47 to 8.57 ¢/kWh	7.47 to 9.91 ¢/kWh
Estimated greenhouse gas reduction from electricity generation	24%	38%	44% to 91%

*Calculation includes RE generation from RPS, utility subscription, and retail providers.
**Calculation only includes RE generation from utility subscription and supply choice and excludes generation from RPS. ***Includes stranded assets.

Appendix A: Factors Impacting Renewable Energy Access

Corporate access for renewable energy procurement depends on a variety of factors, many of which are not under the buyer's direct control. Some of these are the result of regulatory and policy landscape, such as the design of the electricity markets and renewable energy policies, or lack thereof, that affect the overall set of options for procurement. These factors also impact system planning and cost recovery processes, which ultimately dictate renewable development and costs of renewables in a state. In addition, there are geographical factors, such as sunlight coverage and wind speeds that impact renewable energy costs. The following section reviews the various factors impacting renewable energy access for commercial and industrial (C&I) customers.

A. Market Structure

Electricity market structures can heavily influence both the development of renewable energy and the access to renewable energy for customers. Market structures are defined as the set of policies that dictates how electricity is developed, dispatched, and distributed to customers. Market structures vary from state-to-state, but can be summarized by three primary types found in the U.S.:

1. <u>**Vertically-integrated Utilities without Participation in Organized Wholesale Markets:**</u> Incumbent utilities own electricity generation, transmission, and distribution. Electricity resources are developed through utility integrated resources planning and incumbent utility is customers' only option for buying electricity.
2. <u>**Participating in an Organized Wholesale Market without Retail Choice to C&I Customers**</u>: Incumbent utilities own transmission and distribution, but electricity generation is provided by competing generator companies within a market operated by an independent organization. Electricity resources can be developed by any developer based on economic market conditions and incumbent utility is still customers' only option for buying electricity, although the source of the electricity is the wholesale market.
3. <u>**Participating in an Organized Wholesale Market with Retail Choice for Customers:**</u> Similar to #2, except that customers have other options than their incumbent utility to

buy electricity. Retail suppliers can sell electricity directly to customers. Retailers procure electricity themselves, either through long-term contracts or market purchases, and deliver electricity through the utility transmission and distribution grid for a fee paid to the utility.

The following section reviews the differences between these market structures and their effect on renewable energy development and customer renewable access.

1. The Role of the Vertically-integrated Utilities without Participating in Centrally Organized Wholesale Markets

In regions without centrally organized wholesale markets, utilities own and operate generation, transmission, and the distribution of assets. In the U.S., these regions serve roughly one-third of electricity demand and are typically states that have not undergone deregulation or allow third parties to provide supply to their retail customers. In these regions, the development of new generation resources is often limited to the incumbent utilities' integrated resource planning (IRP) processes, where the utilities develop their own resources or procures resources from third-party developers via long-term contracts. In these regions, the incumbent utility is customers' sole supplier for electricity. Therefore, customers' access to renewable energy is limited to the utility offerings, which may be limited. Moreover, customers have little direct influence on how much new renewable resources would be developed, as the utility and the state regulators control the supply development process. In the absence of a specific state or federal policy setting a renewable energy target, utilities will procure the generation mix that optimally procures the lowest cost of electricity. Historically, renewable energy resources have not been heavily featured in utility IRP procurements without additional clean energy policy, such as RPSs. However, the procurements in the past two years have started including more renewables, such as Georgia Power's recent IRP that plans to procure 2.2 GW of solar by 2024 due to renewable energy cost declines.[117]

Nevertheless, this overall market structure can be restrictive for C&I customers seeking to procure renewable energy and presents several challenges:

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[117] Kelly Pickerel, "Georgia Power will add 2.2 GW of renewable power, 80 MW of energy storage by 2024," *Solar Power World*, July 16, 2019, accessed January 21, 2020.

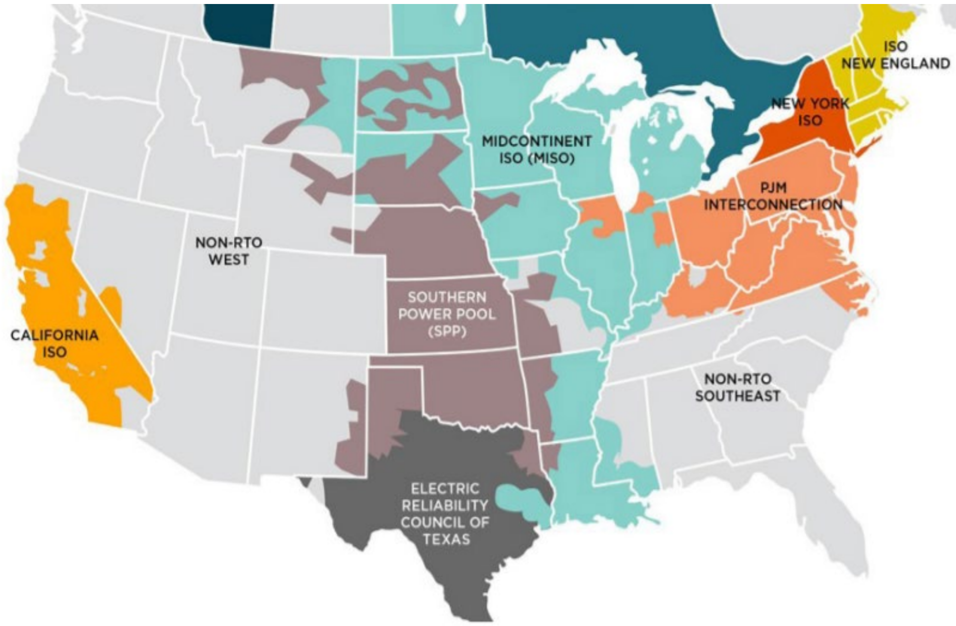
- C&I customers depend on the utility for renewable development and renewable procurement options.
- Procurement options are often based on subscriptions-based programs, which do not necessarily reflect customer preferences for the terms and the type of the resource.
- Additional administrative costs and/or other generation-related costs may hinder/slow down the rate of offerings.

Without market structure reform or state policy, C&I customers in states without centrally organized wholesale markets will need to work with utilities to both develop renewables and provide access to C&I customers.

2. The Role of Centrally Organized Wholesale Markets

In the late 1990s and early 2000s, centrally organized wholesale energy markets were adopted in several regions of the U.S. in an effort to efficiently manage the supply resources. In centrally organized wholesale markets, developers can develop generation projects and these generation assets can be competitively dispatched by an independent system operators (ISO) or regional transmission organizations (RTOs). ISOs/RTOs operate markets to dispatch the cheapest mix of supply (and demand) resources based on their marginal costs of electricity production while ensuring that electricity is reliably delivered to customers. Utility generation that is dispatched by the ISOs/RTOs receive price signals from the wholesale market. All utilities continue to own the transmission and distribution, but the ISOs/RTOs plan and operate the transmission assets. Without retail choice, which will be discussed in the next section, the incumbent utility is still customers' sole option for buying electricity. Today, roughly two-thirds of U.S. demand resides in regions with centrally organized wholesale energy markets (Figure 27).

Figure 27
Map of North American ISOs and RTOs



Source: The Brattle Group.

An important aspect of centrally organized wholesale markets is that it allows open access for any developers to sell into the energy market. This removes the limitation of relying on local incumbent utilities for renewable purchases, as with the case in regions without organized wholesale markets. If anticipated organized wholesale energy market revenues are sufficient, or if a load-serving entity or customer would be willing to enter into a PPA with a renewable energy project developer/owner, the developer can develop the project and readily interconnect it to the organized power market. Moreover, resource dispatch is based on marginal costs of production of the generation mix. This is especially advantageous for renewable energy where the marginal costs of zero and outcompete fossil's marginal costs. Analysis of states with similar renewable resource quality has shown that regions with centrally organized wholesale markets experience significantly more renewable development.[118]

More broadly, it is widely accepted that well-designed centrally organized wholesale power markets can provide many benefits through facilitating a diverse generation mix, pooled dispatch, marginal cost pricing, and coordinated transmission planning.[119] While the magnitude of benefits

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118 Sanem Sergici, "The Status of Restructuring: Whole and Retail Markets," presented to the National Conference of State Legislatures, June 26, 2019.

119 *Ibid.*

will be region specific, the leading benefits of centrally organized wholesale markets can be summarized as follows:

- Lower cost of power production: Markets are set up so that generation resources compete to produce the power needed to serve customers. Competition means that the region's lowest-cost resources will produce power more frequently, substituting production from the higher-cost generators, and delivering savings to electricity consumers. Savings originate from three sources: (1) utilities purchase less fuel and spend less on variable operation and maintenance (O&M) for the higher-cost power plants that operate less after the competition is introduced, (2) utilities are able to buy power from the market to serve customers at a lower cost than producing it themselves, and (3) utilities with low-cost generation can make more sales into the market and earn higher revenues, which are used to offset other costs charged to customers. Retrospective analyses have calculated benefits of billions per year.[120, 121]

- Efficient investment decisions: Regional markets can help participating utilities avoid or defer investments in transmission and generation resources, creating savings for electricity customers. The large regional market, where access to transmission is open to all participants, requires fewer generation facilities to reliably operate the system. The market provides a clear price signal to developers about which types of resources and at what locations provide the best return on investment, which results in more efficient generation investment and retirement decisions over the long term.

- Integration of wind and solar: Production from wind and solar resources is intermittent, which can create costly operational challenges for the electric power system. Participating in a centrally organized wholesale market reduces these challenges as the risk associated with variable output from renewable energy is diversified over a larger region.

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120 "2018 MISO Value Proposition," Midcontinent ISO, February 2019, accessed January 21, 2020.

121 "PJM Value Proposition," PJM Interconnection, 2019, accessed January 21, 2020.

- **Improved reliability:** The regional scheduling and dispatch of the transmission and generation allows the RTO or ISO to improve transmission availability and better manage unexpected facility failures on the system.

In the absence of retail choice, customers in regions with centrally organized wholesale market are still required to buy their power from their local utility. However, operating in a centrally organized wholesale market, utilities have greater access to renewable resources (to procure energy and/or renewable energy credits, or both), and therefore customer access to renewable energy also potentially improves. One option that does present itself upon the participation in a centrally organized wholesale market for large-scale customers, is the procurement of renewables through PPAs directly from the market, which we will discuss more in detail below. Further, as described above, it is more cost effective for the system to integrate large-scale renewables within a large wholesale system that includes a diversity of resources including renewable resources, and other generation and storage resources. Markets will be even better equipped to integrate renewables with anticipated market rule changes facilitated by FERC Order 841 to better incorporate battery storage.[122] These elements ultimately reduce customer costs of procuring renewables, whether it be through utility programs or PPAs.

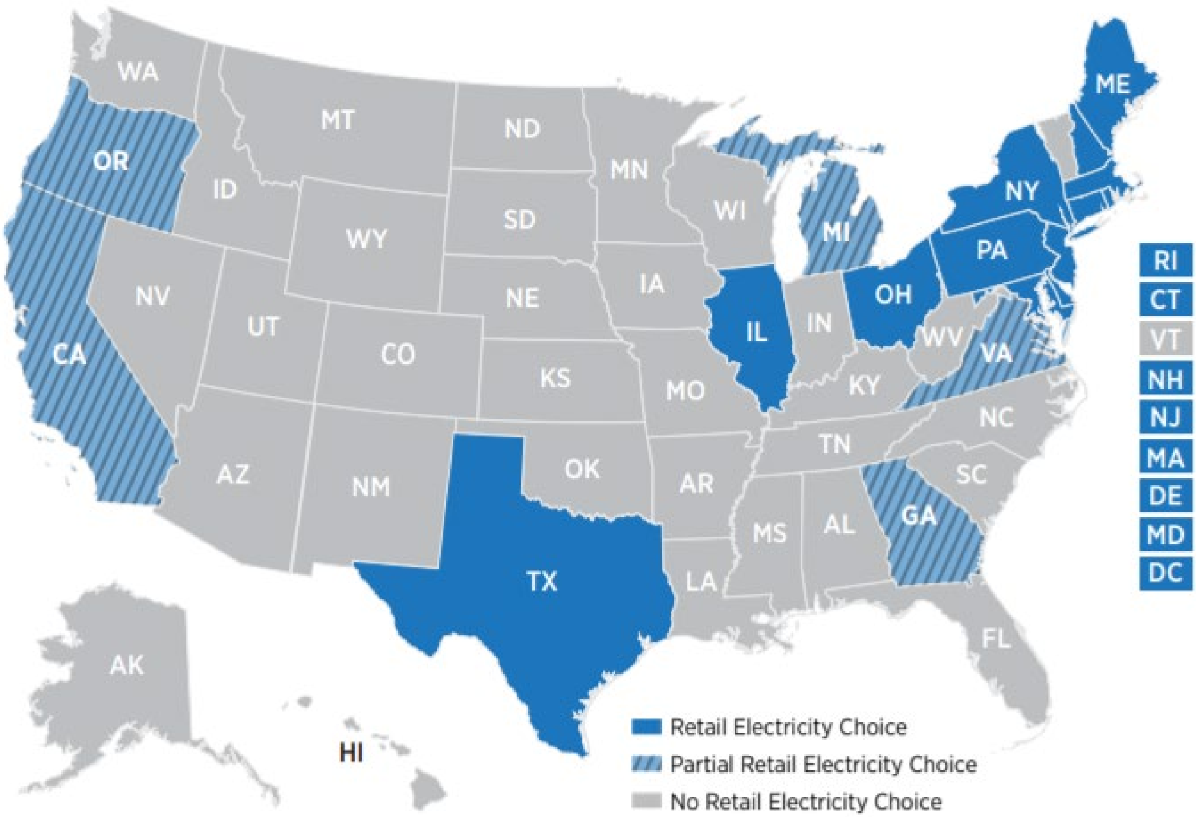
3. The Role of Retail Choice

Alongside the introduction of centrally organized wholesale markets, retail choice was also introduced to several states in the 1990s and 2000s. Retail choice opens up access for retail electricity suppliers ("REPs" or "retailers") other than the incumbent utility to provide electricity to customers. Under this market structure, customers will continue to buy transmission and distribution services from their incumbent utility, but can choose from various retail suppliers for their power purchase. These retailers can buy electricity supplies from the centrally organized wholesale market, their own generation, or bilaterally contracted resources, to provide electricity to customers. Retail choice was introduced to substitute regulated electricity supply by the incumbent utility with competition to drive prices down. Driven at the state-policy level, states also sought to promote innovative rate and technology offerings, improved energy hedging by retailers, and access to renewable energy through retail supplier programs. Today, full retail choice

122 Robert Walton, "Brattle: US storage market could reach 50 GW if costs keep declining," UtilityDive, February 26, 2018.

exists in 13 states (and the District of Columbia) and partial supply choice (for a select subset of customers) exists in a few other states (Figure 28).

Figure 28
Map of Retail Choice Access in the United States



Source: National Renewable Energy Laboratory. "An introduction to supply choice in the United States."

Texas serves as a particularly interesting example of an established retail access market. Unlike other jurisdictions with retail choice, utilities are not tasked with the provider of last resort ("POLR") responsibilities. The utilities commission designates one of the retailers with the responsibility of the provider of last resort in each area for when the customer has not yet identified a retailer. This provider is designed to have a relatively expensive price in order to push customers to the retail market. As a result, all customers are subscribed to one of many retail providers. There are over 100 retail energy providers operating in Texas, offering nearly 100 renewable energy offerings. As such, the state has been able to provide all customers with cost-effective renewable procurement options.[123]

In general, using competitive suppliers was quickly adopted by a majority of C&I customers while residential adoption has been lower (See Figure 29). Adoption to competitive suppliers has stagnated since retail choice was introduced, and retail providers have received some scrutiny on their billing, pricing, and marketing practices.[124] Moreover, the assessment of whether retail choice has led to lower prices is a complex one, as this comparison (although used as a common metric) does not always compare similar products.[125] Therefore, it's unclear whether introducing retail choice has led to significant cost reduction for customers. One of the most contentious issues with introducing retail choice is the potential for stranded assets for the incumbent utilities. Stranded costs would need to be recovered from customers if the utilities who made those investments are allowed to earn their returns on investments.

For the purpose of this report, and associated analyses, we have assumed that one of the pathways is to provide C&I customers with supply choices (even if the state does not implement full retail choice) so that they can choose to purchase and use renewable energy resources at will. However, to do so, some of the prior utility-based generation investments may become stranded. While we do not conduct a full stranded costs analysis, we assume that a range (25-75 percent) of the book value of the incumbent utilities generation may be subject to the risk of stranded costs.

It is important to note that community choice aggregation (CCAs) and municipalization have emerged as options that lead to the switching of a large number of small and large customers to an alternative provider other than the incumbent utility. Most CCAs' value proposition is to provide customers energy from renewable resources that are generally procured through PPAs. While this option improves the "overall greenness" of the grid electricity, it does not necessarily provide additional choices for large scale buyers who are making ambitious commitments for renewable energy procurement that are above the CCAs' commitments.

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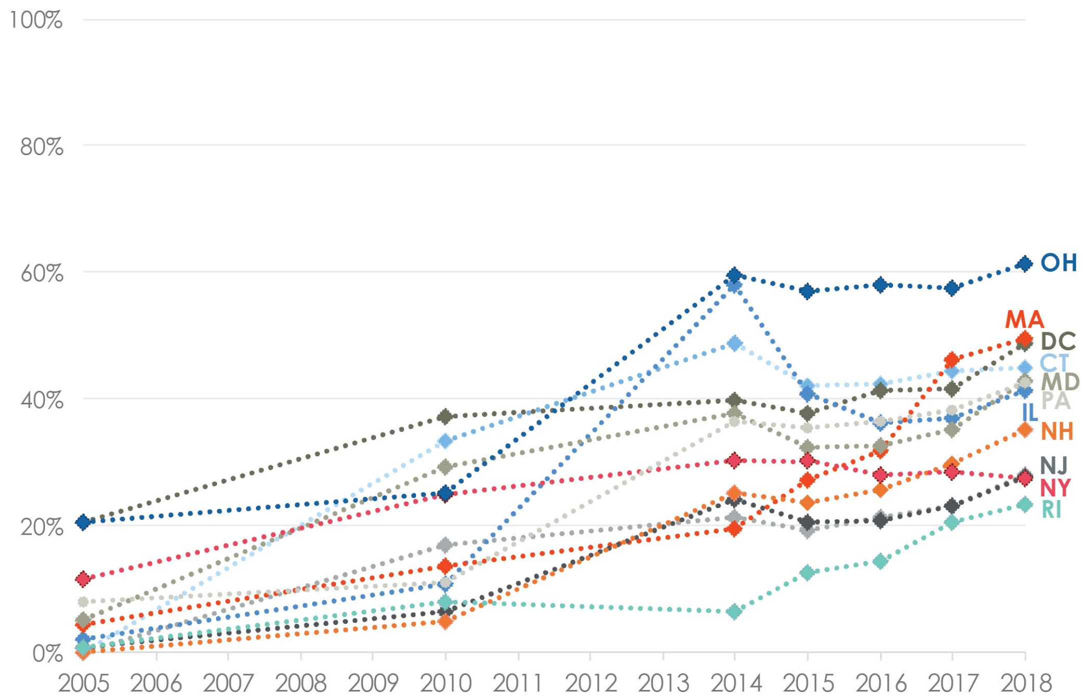
123 "An introduction to retail electricity choice in the United States," National Renewable Energy Laboratory, August 2017, accessed January 21, 2020.

124 Frank Graves et al., "Retail Choice: Ripe for Reform?," The Brattle Group, July 2018.

125 Distribution utilities as POLR providers usually cannot earn a profit on electricity sold as a default service, which makes the default service rate a poor benchmark for whether retail providers are providing cost-savings. In some cases, the end product purchased by the customers from retailers might also be different; i.e. time varying rates with smart home management technologies.

Figure 29
C&I Customer Historical Retail Choice Adoption by State



Note: Texas is excluded from this figure since Texas Retail Electric Providers serve 100% of addressable customers. Source: Data from EIA (Form EIA-861).

A potential benefit of providing retail choice to C&I customers is that retailers can respond to customer demands for renewable energy products, procure renewable energy through long-term contracts or market purchases, and package the energy in retail products for customers. In 2015, over 20 percent of renewable energy sold in the U.S. was through competitive retailers.[126] To date, many retailers have chosen not to bear the financial risk of new renewable development and instead opt to buying renewable energy credits in marketplaces. In addition, some retail offerings have also lacked transparency in what renewable resources they are truly supporting and the full costs. While more standardization is needed to ensure customers are subscribing to renewable energy products that are driving new renewable development, the retail choice framework provides a competitive market to innovate new products for customer demand.

126 *Ibid.*

B. Utility System Planning and Cost Recovery

Most utilities in the U.S. are required by the state statute or policies to file Integrated Resource Plans (IRPs) that represent a plan for meeting the future demand and energy plus planning reserve margins through existing and planned mix of resources. In developing IRPs, utilities have an obligation to minimize their system costs while taking into account long-run public policy goals such as RPSs, or other statutory goals. IRPs typically are used by utilities to plan resources over a 15- to 20-year timeframe; rely on both supply and demand resources, and model various scenarios that represent the uncertainty in changing demand and supply conditions.

With the increasing penetration of distributed energy resources (DERs), renewed emphasis on energy efficiency due to clean energy policies, and falling costs of renewable energy resources, utility IRPs have exceedingly become sophisticated and require extensive stakeholder processes. Several IRPs have recently been rejected by regulators due to limited consideration of demand side resources or renewable build out; and led to lengthy processes that involved revision of the plans for resubmission.[127] Since the utilities select the cost-minimizing resource mix through the IRP process, renewable resources selected in the plan represents the optimal level and any deviation from these levels could indicate a cost increase. Moreover, if the renewable resource development to meet an ambitious renewable energy or emissions reduction target could result in pre-mature retirement of fossil fuel generation capacity and stranded assets.

With increasing cost-competitiveness of renewables, early fossil plant retirements have increased stranded costs.[128] Stranded costs arise when historical financial obligations that utilities incurred in the regulated market become unrecoverable in a change in regulation or a transition to having to compete in a market setting. There are three widely used methods to mitigate stranded assets. The first approach involves "creation of a regulatory asset" that allows for undepreciated plant costs to be recovered through rates. The asset is assigned a normal utility return on the remaining book life of the sunk costs. The second approach is "securitization," in which assets are packaged into securities and sold to investors, with cash flows coming from utility ratepayers. This approach was initially used in the context of restructuring in the late 1990s to recover cost of generation

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127 Trabish, Herman, "Regulators push Hawaii utilities towards new business models," *Utility Dive*, April 30, 2014, accessed January 10, 2020.

128 Larry Pearl, "2020 Outlook: 10 trends driving the US power sector," *Utility Dive*, January 13, 2020.

assets rendered uneconomic (market value is less than book value) by competition. It has recently been used to recover costs of generation retirement due to environmental compliance requirements. While more complex in implementation, it lowers costs to ratepayers by financing the amount through the issuance of bonds at low interest rates. The third approach is "shift/accelerate recovery", which involves shifting the recovery of undepreciated costs to other non-stranded assets and depreciating on an accelerated timeframe. Selection of one of these three approaches in a given jurisdiction is typically governed by the presence of precedents, but resulting rate impacts for the ratepayers is also a leading factor. Regardless of the selected approach, embedded costs and stranded asset costs are recovered from the ratepayers.

Moreover, when utilities procure renewable resources outside the IRP process (beyond what is implied in the resource plan) to create a subscription program/tariff, it is essential that the cost of this subscription program is not shifted to other ratepayers and only borne by the customers who are subscribing to it. Utilities also ensure that the cost to the subscribing customers is not lower than other customers of the same class, as this would be deemed discriminatory, leading to questions such as "why not procure cheaper electricity for everyone if that opportunity already exists?" If the levelized costs of new renewables (all-in, including RECs) is below the cost of new fossil generation in a state, utilities have an obligation to procure new renewables for all customers. This however should occur through the IRP process as discussed above and has been in most states (and has even resulted in utilities shutting down coal plants early and replacing them with new renewables because it made economic sense).

Another important area in utility planning is long-term transmission planning. Regardless of being part of a centrally organized wholesale market or not, FERC Order No.1000 requires each public utility transmission owner to participate in this regional planning process and identify cost-effective solutions to their mutual transmission needs.[129] While this can be a complex process, the importance of regional coordination, urgency of identifying essential transmission developments, and starting the development process are heightened with the increasing renewable energy

[129] Ralph Luciani and Maggie Shober, "Transmission Planning Whitepaper," Navigant Consulting, Inc. for EISPC and NARUC, January 2014, accessed January 21, 2020.

development across the U.S. Lagging transmission development might be one of the biggest barriers to increased customer access to renewable energy through utility development.[130, 131, 132]

C. State-level Renewable Energy Policies and Utility Decarbonization Commitments

One of the primary drivers of renewable development in the U.S. has been mandatory state renewable or emission targets: over 300 localities have committed to such targets.[133] In addition, thirteen states, including the District of Columbia, have set 100 percent clean energy goals.[134] Such targets mandate that utilities, municipal cooperatives, and other electricity retailers procure a portion of their electricity from renewable or clean energy sources.

These policies usually take three forms. The first is the implementation of a mandatory statewide RPS or clean energy target, which mandates that a certain percentage of electricity sold by utilities within a state come from renewable or clean sources. Utilities procure a percentage of their electricity by purchasing renewable energy through many mechanisms, such as power purchasing credits (RECs), zero emission credits (ZECs), long-term contracts with developers, or REC/ZEC markets. Failure to do so results in the utilities incurring a penalty.

Historically, such mandates have been introduced and made into law through state legislation, such as in California,[135] or governor executive orders, such as in Virginia.[136] Another distinction for such mandates is whether they are for renewable energy or clean energy, the latter including

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130 Alexander E. MacDonald, Christopher T.M. Clack, Anneliese Alexander, et al., "Future cost-competitive electricity systems and their impact on US CO2 emissions," *Nature Climate Change* 6(2016)526–531.

131 Herman Trabish, "Is a national high voltage transmission system the cheapest way to cut emissions?," *Utility Dive*, Febrauary 19, 2016, accessed January 10, 2020.

132 National Renewable Energy Laboratory, "Interconnections Seams Study," accessed January 10, 2020.

133 Herman K. Trabish, "As 100% renewables goals proliferate, what role for utilities?" *UtilityDive*, April 2, 2019.

134 Julia Pyper, "Tracking progress on 100% clean energy targets," Greentech Media, November 12, 2019.

135 Julian Spector, "California Assembly Passes Historic 100% Carbon-Free Electricity Bill," Greentech Media, August 28, 2018.

136 Catherine Morehouse, "Virginia Gov. Northam orders 100% carbon-free power by 2050," *UtilityDive*, September 18, 2019.

other non-emitting technologies such as nuclear or carbon capture and sequestration. For example, California has both renewable and clean energy mandates with a 60 percent renewable energy mandate by 2035 and a 100 percent clean energy mandate by 2045.[137] The reasons for distinguishing clean energy from renewables include supporting local nuclear facilities and allowing a more diverse set of technologies to reduce emissions, which have been shown to reduce system costs and help achieve decarbonization goals.[138] Customers in states with mandated renewable targets will receive a portion of their electricity from renewable resources by default.

The second form that renewable mandates take is economy-wide emission targets, such as Massachusetts' 80 percent economy-wide emission reduction goal by 2050.[139] These targets influence renewable development and procurement indirectly through the need to decarbonize electricity. These targets have the added effect of incentivizing energy efficiency and electrification, such as the adoption of electric cars.

The last form that renewable mandates take are aspirational state or utility goals that encourage the adoption of renewable energy, but do not require it by law. An example is Xcel's 100 percent carbon-free electricity by 2050 goal.[140] These goals are set to respond to either shareholder ambitions or customer demand to contribute to climate change mitigation. In such cases, renewable development occurs in an effort to meet the aspiration goal, but no penalties incur for failure to do so. As such, these aspirational goals are less certain than legislated mandates.

While mandates that ultimately reduce emissions are growing in popularity, there is a noticeable geographic difference among the states in their adoption of renewable energy goals (Figure 30). States in the Northeast and the West have historically adopted strong and mandatory goals, often times economy-wide. In contrast, states in the Southeast have no or very low statewide renewable energy goals, despite strong renewable resources.

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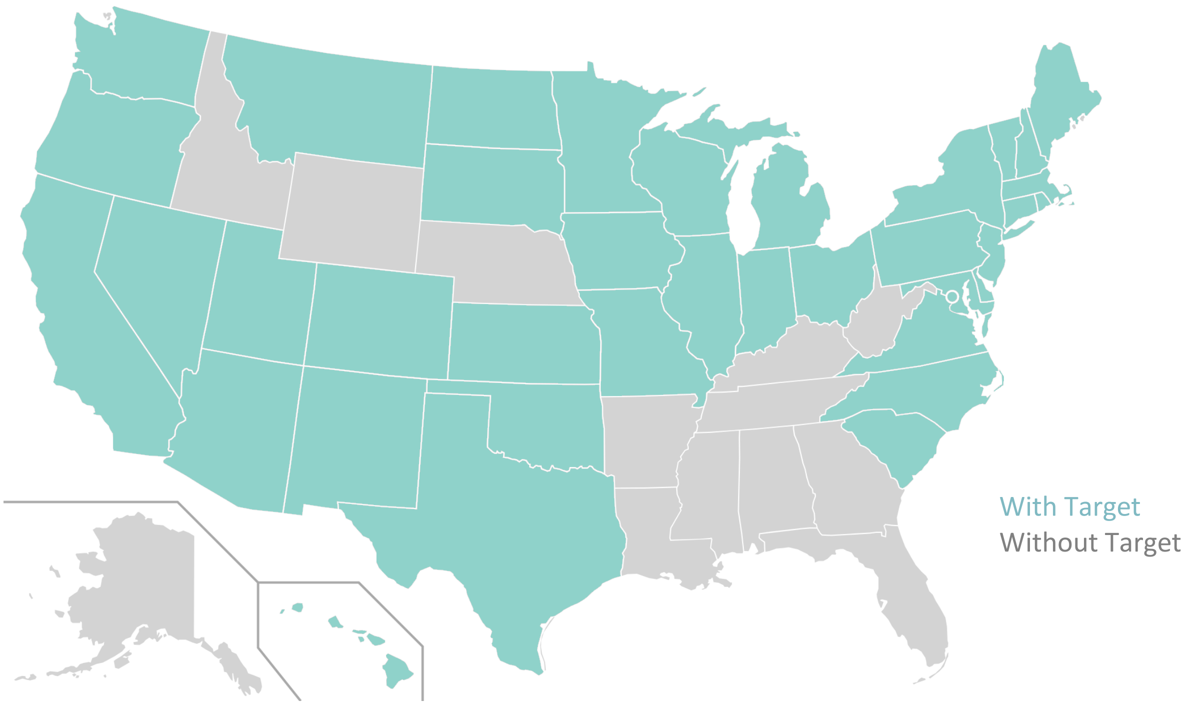
137 Spector, 2018.

138 Nestor A. Sepulveda, Jesse D. Jenkins, Fernando J. de Sisternes, and Richard K. Lester, "The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation," *Joule* 2 (2018): 2403–2420.

139 "Global Warming Solutions Act Background," Mass.gov, accessed December 26, 2019.

140 "Your Clean Energy Future," Xcel Energy, Accessed January 21, 2020.

Figure 30
Map of States with Renewable or Emission Target

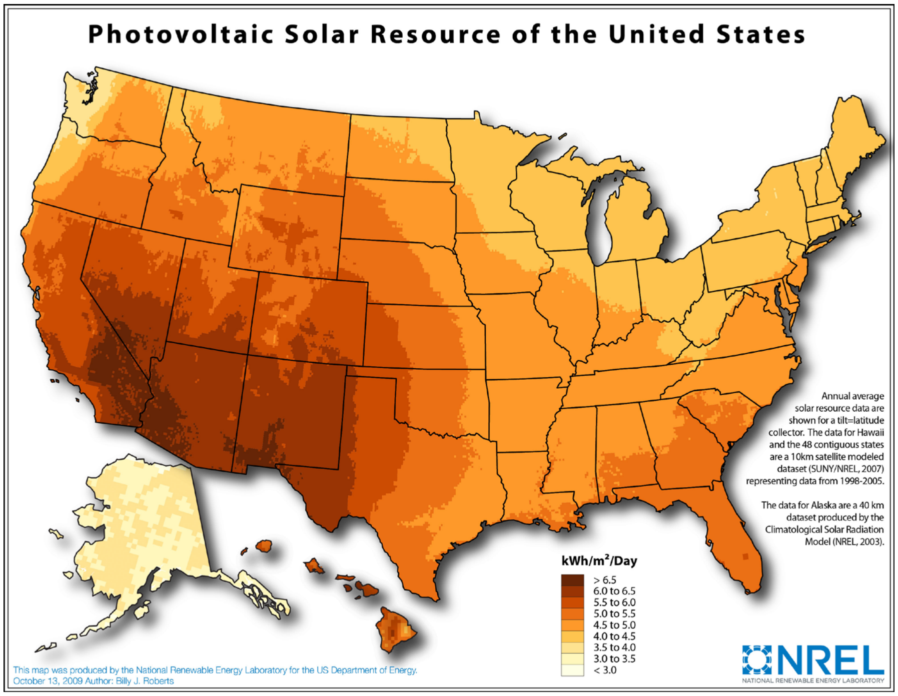


Source: Based on information from the National Conference of State Legislatures

D. Local Geography and Renewable Resources

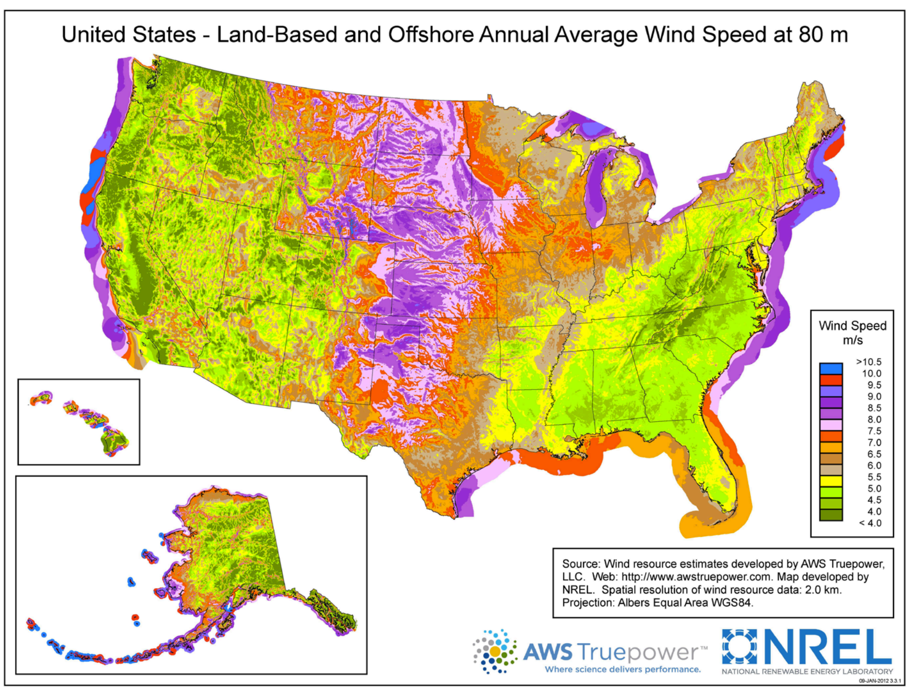
In addition to policies and market structures, the favorability of developing renewable energy also depends on the quality of the renewable resources in a locality. The distribution of the quality of solar irradiance (Figure 31), which quantities the amount of sunlight a region receives, and average wind speeds (Figure 32) varies across the United States. Some regions, such as the Southwest, are more suited to solar power than others, while regions such as the Midwest are more suited for wind generation.

Figure 31
Sun Irradiance over the Continental United States



Source: Solar Maps, NREL.

Figure 32
Average Annual Wind Speed at 80 Meters Height



Source Wind Maps, NREL.

Quality of a renewable resource is measured by its capacity factor which represents the ratio of its actual output over a period of time to its potential output if operated at full nameplate capacity during the same period of time. For renewables, this is often directly related to the quality of the renewable resource in the locality, which ultimately effects the levelized costs of electricity (LCOE) of renewable energy, the average cost per MWh.

The LCOE of renewables, as determined by natural renewable resources and other factors, such as local land costs, relative to the costs of the local generation mix effects the competitiveness of renewables and ultimately the renewable development. As an example, before significant cost reductions in onshore wind from 2005-2015, the LCOE of renewables in the Northeast failed to be competitive with local fossil generation. Without significant transmission to import hydropower from Canada or wind from the Midwest, renewable activity in the Northeast was limited to low-quality renewable resources. This can be compared to the Southwestern region of the U.S., which has high-quality solar resources and solar power has been cost competitive with local fossil generation for many years.

Appendix B: Renewable Energy Procurement Options

Customer renewable energy procurement options exist for every market structure (Table 31), however which options are available can be limited by the market structure in the state. As an example, wholesale contracts, such as PPAs, have been tremendously popular among large-scale buyers, but are limited to states that are in centrally organized wholesale markets. Yet, utilities can provide similar options through utility-sleeved contracts in states without centrally organized wholesale markets. The details of each option will be reviewed in detail in the following section.

Table 31
Renewable Energy Procurement Options

	RE Buyer and Customer Relationship	Price Risk	Common barriers	Market Structural Needed
State and Utility Goals/Mandates	• Typically, the utility is the counter party (buyer) that procures RE from developers • Customer receive a share of RE through regular utility service	• Short-term price risks are relatively low, as utilities will provide fixed electricity rates. • Long-term prices are dependent on future utility procurements.	Alone, state and utility goals lack customer empowerment/ choice	None
Utility Subscription Program	• Typically, the utility is the counter party (buyer) that procures RE, planned via IRP. • Customers subscribe to RE through a utility program.	• Price risks depends on the program rate. • Fixed rates provides certainty while variable rates do not.	Often, programs are limited in total MW (or MWh) available and have costly premiums and other inhibitive fees.	
Utility Sleeve Contract	• The utility is the counterparty (buyer) to renewable owner and "sleeves" RE through to customer.	• Price risks can be low as sleeve contracts provide fixed charges.	High effort and knowledge needed which excludes smaller buyers.	
Utility Market-rate based Program	• Utility buys renewable wholesale energy at market-based prices and customers buys at same price.	• Variable market prices cause price risks for customers, unless paired with a PPA.	Buyers are exposed to wholesale market electricity price uncertainties, unless paired with a PPA.	Centrally organized wholesale market
Standardized Wholesale RE Contracts	• The customer is the counterparty (buyer) of a PPA from developer.	• Low price risk as the PPA provides an energy price hedge in the local market.	High effort and knowledge requirements mean that it may not scale easily.	
Standardized Retail RE Contracts	• A retail supplier is the counterparty (buyer) of PPA or procures RECs through markets and sells aggregated RECs to the customer.	• Price risks depend on the contract rate. • Fixed rates provide certainty while variable rates do not.	If not designed properly, contracts may lack transparency or standardization, resulting in buyers being unsure of the best offering.	Centrally organized wholesale market and supply choice

The ease for customers to use these options and their effectiveness to support the development of new renewables varies significantly by state and utility. While PPAs have been a popular option for large-scale buyers, smaller buyers often do not have the resources or knowledge to procure long-term PPAs with renewable developers. Developers are also weary to sign contracts with small businesses for reasons of revenue certainty. As such, renewable energy procurement options need to be designed with both small- and large-scale buyers in mind. Effective procurement options have five primary features:

- **Customer Empowerment:** Customers can choose how much renewables to procure, with the options to procure all of their electricity from renewable resources without energy or capacity limitations.
- **Support New Renewables:** Procurement options should support new renewable development, rather than subsidize old and depreciated renewable plants to drive decarbonization of electricity generation.
- **Ease of Procurement:** Renewable energy procurement options should be easy to procure for large and small customers, which often results from transparent contract terms, easy sign-up procedures, low up-front administrative fees, and reasonable contract lengths.
- **Managing Price Risk for Customers:** Procurement prices should reflect true renewable energy costs with customer contracts designed to hedge against future price fluctuations.
- **Revenue Certainty for Developers:** Procurement options should provide developers with sufficient revenue certainty to allow for development of new renewable resources.
- **Scalability:** Procurement options should be designed in a way to incorporate more customers and develop new renewables to serve these customers.

Generally, state and utility goals and/or mandates provide the largest footprint of renewable development and access to customers. However, these lack customer empowerment to go beyond the mandates set by state laws and goals. These state and utility goals can be supplemented with well-designed subscription programs, where customers can procure their own renewable energy *in excess* of the renewables procured by the utility to meet state/utility goals, with flexible contracts and customizable amounts of procurement. Utility sleeve contracts, market-based contracts, and wholesale renewable contracts provide similar benefits but are usually limited to large-scale buyers that can sign long-term contracts for large amounts of renewable energy. Participating in centrally organized wholesale markets and providing C&I customers with supply choice increases the availability of procurement options, allowing more competition among renewable energy procurement options.

A. Goal/Mandate Driven Renewable Energy Deployment

State or utility mandates/goals drive renewable energy procurement by the utility and this results in a portion of customers' electricity procured from clean energy resources. These mandates/goals usually take three forms: mandatory statewide RPS or clean energy target; mandatory emission limits; and aspirational state or utility goals. For RPS, utilities are mandated to procure renewable energy or credits up to a percentage of their sales, as determined by the RPS. Failing to do so, utilities may incur a penalty in some states. For emission targets and aspirational goals, utilities are indirectly motivated to procure renewable energy to reduce their emissions at least-cost, but enforcement varies and the ability of utilities meeting these goals is less certain.

For this procurement option, the utility is typically the counter party (buyer) that procures renewable energy and their environmental attributes, often RECs, from developers with long-term contracts that range from 10-25 years. Customers receive a share of their electricity from these contracts through regular utility service and retail prices include any procurement costs spread over all customers. For customers, short-term price risks are relatively low but long-term prices are dependent on future utility procurements, the quality of renewable resources that are qualified and available to the state, and the costs of integration as more renewables are added to the grid. The limitation of this option is that state or utility mandates/goals, on their own, lack customer empowerment and choice. Customers passively accept the portion of renewable energy in their grid mix as dictated by goals, and need additional procurement options to go beyond this percentage.

B. Utility Subscription Programs

Utility subscription programs allow customers to procure renewable energy by subscribing to either portions of renewable energy developments by the utility or REC procurements by the utility. There are many variations of such programs across the U.S. and cost structure also varies significantly with premiums either being based on REC costs or a combination of charges and credits meant to reflect net-costs of renewable procurement for the utility.[141]

The REC-based variation is more common in states that are in centrally organized wholesale markets where utilities procure electricity from the wholesale market and supplement their procurements with REC purchases for program subscribers, which the utility retires on the customers' behalf. Customers pay their regular retail rates with an additional premium that reflects the REC procurement price (Figure 33). This structure allows utilities to pass through the costs of REC procurement directly to program subscribers without affecting non-subscribing customers. An example of such a program is Xcel's Windsource program, which allows customers to purchase all of their energy use each month from the wind resource in Xcel's generation portfolio at a premium based on REC prices.[142] These programs are often structured to be easy to subscribe to with short-term contracts and low-cost termination options. One drawback of many programs structured this way is they support already-existing renewable energy projects and do not promote the development of new renewable facilities unless utilities sign long-term PPAs to supply the program.

The second variation, where utilities develop new renewables on their own or through long-term PPAs and allow customers to directly subscribe to a portion of a renewable facility's energy and RECs, is more common in states without centrally organized wholesale markets. An example of such a program is Puget Sound Energy's Green Direct program, which allows customers to subscribe to a portion of the utilities' renewable energy facility.[143] For such programs, utilities charge their default retail service rates, a renewable procurement charge, and a credit based on

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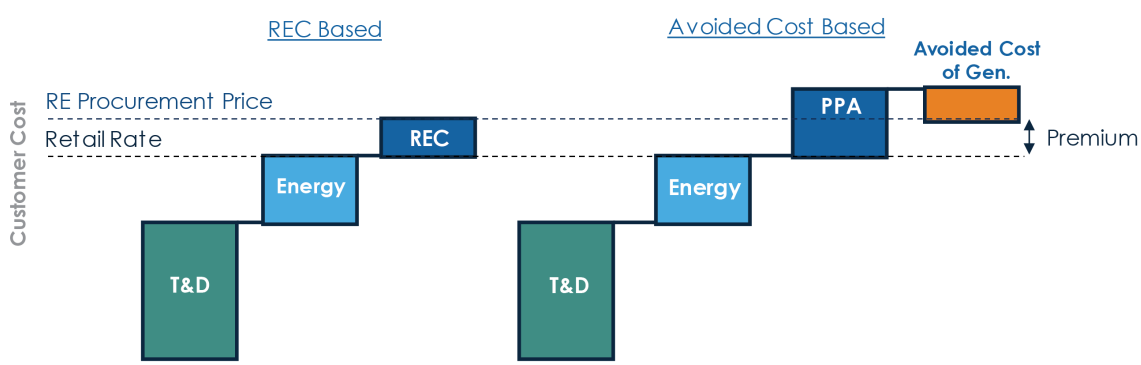
141 Celina Bonugli, "Emerging Green Tariffs in U.S. Regulated Electricity Markets," Renewable Energy Buyers Alliance, November, 2019, accessed January 21, 2020.

142 "Windsource for Business" Xcel Energy, accessed December 27, 2019.

143 Celina Bonugli, "U.S. Electricity Markets: Utility Green Tariff Update," Renewable Energy Buyers Alliance, November 2019, accessed January 21, 2020.

either the avoided costs or time-varying marginal costs of electricity generation that the new renewable facility provides the utility (Figure 33). Such a structure has the potential to lower rates for customers if the avoided costs of generation are high. However, this prospect is not certain. As more renewables are integrated into the grid, avoided costs of generation may fall, especially during the times when renewable facilities are generating electricity. These programs can have either fixed or variable rates/credits, which can affect the price risk to buyers. One benefit of such a program is that it is often for new renewable development, ensuring customer subscriptions are leading to societal emission reductions. The downside of this variation of subscription program is that it is often limited in size to the utility renewable procurement, which may be lower than customer demand.

Figure 33
Schematic of Utility Subscription Program Cost Structures



Utilities will often structure programs to ensure non-subscribing customers do not incur costs on the behalf of subscribing customers. As such, large-scale utility subscription programs often do not offer cost savings relative to the retail rate. However, the avoided-cost based variation provides customers an opportunity to minimize the premium they pay for electricity while also supporting the development of new renewable facilities. Additional charges may also apply that account for renewable integration costs. As an example, Xcel Energy Colorado's Renewable*Connect program charges a solar integration cost as part of the program procurement charge.[144]

144 *Ibid.*

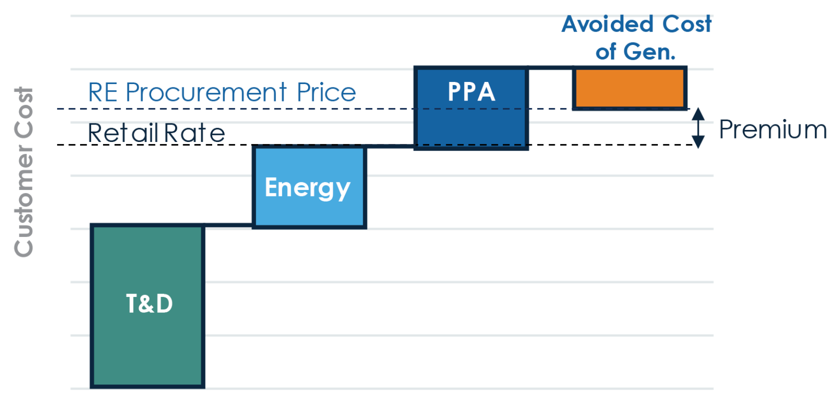
To better meet the need of customer demand, utility subscription programs will need to support new renewable development and structure costs to allow the opportunity for customers to minimize the procurement premium. Short-term contract terms with low-cost termination fees also have the potential to expand access to renewable energy for many smaller customers. Such programs would have a high ease of procurement for small- and large-scale buyers, and can be scaled-up relatively easily as new facilities are developed. Importantly, such programs can give customer empowerment in states without a centrally organized wholesale market, where customer choice is limited. To continue to meet growing demand for renewable programs, utilities will need to learn how to expand such programs while addressing expansion concerns, such as stranding old inefficient resources and allocating stranded costs for demand that is willing to pay the premium for renewable energy.

C. Utility Sleeve Contracts

In states without centrally organized wholesale markets, PPAs are not possible, as utilities control the resource development and other developers cannot gain access to directly sell to customers. To allow large buyers to procure renewables, some utilities have provided an alternative option, such as utility sleeve contracts. These contracts allow customers to procure renewable energy from a specific renewable project through a utility. The terminology “sleeve” reflects that these contracts, often PPAs, are “sleeved” through the utility to the customer for a fee. In these programs, buyers do not contract directly with the developers, but rather with a utility that either has an existing PPA with a renewable generator or brokers a new renewable PPA with a developer on the customer’s behalf.

Generally, these contracts are structured such that the customers pay their regular retail rate and are charged a fixed price for the PPA minus a credit that may reflect the avoided costs of generation of the utility as a result of the new renewable power plant. The resulting price to the customers typically results in a premium on top of their retail rate if and when the avoided cost of the generation is lower than the cost of the PPA (see Figure 34 below).

Figure 34
Schematic of Sleeved Contract Structure



Source: The Brattle Group

An example of a sleeve contract is Duke Energy's Green Source Advantage (GSA) program.[145] Customers, through the utility, negotiate a PPA for energy and RECs with contract lengths that range from two to 20 years. After negotiations are complete, Duke enters into a PPA with the renewable project and receives energy from the project and retires the RECs on the customers' behalf. In addition to the retail rate, subscribing customers receives the following charges/credits:

- **GSA Product Charge:** The energy produced by the renewable facility in the prior billing month multiplied by the fixed rate for energy supplier specified in the PPA.
- **GSA Bill Credit:** The energy produced by the GSA facility in the prior billing month times the GSA Bill Credit rate. The GSA Bill Credit is based on one of two options that can be selected by the customer:
    - **Avoided Fixed Costs:** Two- or five-year forecasted avoided utility fixed costs, depending on the contract length. If contracts are above five years, bill credits are adjusted every five years.
        - Hourly marginal avoided costs can provide an energy hedge that reflect pass-through costs on regular retail bills.

145 "Green Source Advantage," Duke Energy, accessed December 27, 2019.

- **GSA Administrative Charge:** The applicable monthly administrative charge shall be $375 per customer account plus an additional $50 charge per additional account billed.
- **Application Fee:** One-time application fee of $2,000.

The benefit of sleeved contracts is that they often lead to development of new renewable resources, which will likely reduce electricity generation emissions. In addition, if properly designed, the cost to the customer accurately reflects both the development costs and value of the renewable energy plant to the local system. If the renewable energy generated results in large avoided costs of generation for the utility, the customer might receive a large credit that will offset a portion of the costs of the PPA. This provides customers an opportunity to have low renewable energy procurement prices. Generally, price risks over time are fairly low for customers as the prices of the PPAs are known when the contracts are signed. However, future avoided costs of generation may change as the grid mix changes, introducing some uncertainty regarding the net premium the customer will pay (unless it is fixed at the start of the contract).

The drawbacks of this option are similar to the drawbacks of regular PPAs (discussed below), which are that they require long-contract terms, significant effort, or knowledge to negotiate a PPA price with the utility and developer. In addition, some utilities charge large administrative fees, which can limit sleeved contracts primarily to large-scale customers. Lastly, these programs are often capped at a specific capacity of the utility's new renewable procurements to avoid stranding assets and have historically been fully utilized by large-scale buyers quickly, limiting availability for other customers.

D. Utility Market-Based Contracts

Utility market-based rate (MBR) contracts are a form of sleeve contract between customers and the utility that allows a customer holding a PPA with a renewable facility in the same jurisdiction to hedge their energy cost. An MBR contract allows customers to substitute time-varying wholesale rates for the traditional utility retail rate in order to hedge their energy costs and avoid over-paying when wholesale prices are lower than the retail rate. The following illustrative example, which focuses on just the energy component of a customer's bill, presents how an MBR contract that has a price of $25/MWh can help a customer (using one hypothetical hour) reduce costs when the wholesale energy price is $20 per MWh and the retail energy price is $30 per MWh (Table 32).

Table 32
Comparison of Hourly PPA Performance during Hypothetic Hour under MBR

Price Component	No MBR	With MBR
PPA Price	Company has PPA at fixed price with renewable facility at $25/MWh	Company has PPA at fixed price with renewable facility at $25/MWh
Wholesale Price	Renewable facility sells electricity and receives wholesale price of $20/MWh	Renewable facility sells electricity and receives wholesale price of $20/MWh
Retail Rate	Company pays annually fixed retail rate of $30/MWh	Company pays wholesale energy costs of $20/MWh
Price Settlement between Company and Renewable Facility	Company pays renewable facility $5 MWh	Company pays renewable facility $5 MWh
Total Company Cost	Company pays both the utility rate and the settlement transfer ($30/MWh + $5/MWh), for a total of **$35/MWh**	Company pays both the utility wholesale rate and the settlement transfer ($20/MWh + $5/MWh), for a total of **$25/MWh**

In this hypothetical hour, the company saved $10 for their electricity rate using the MBR contract. While not all hours will provide potential cost savings, this allows customers cost savings when the occasion arises. However, additional charges may reduce the financial benefits of such a contract. Given the nature of this contract, the benefits are limited to large-scale buyers in centrally organized wholesale markets who are procuring renewable PPAs, much like sleeve contracts or regular wholesale contracts.

The distinguishing feature between MBR contracts and sleeve contracts is that MBR contracts are compliments to already-existing PPA contracts that customers have procured in a centrally organized wholesale market, rather than PPA contracts negotiated through the utility. Utility MBR contracts are not common. An example of a utility MBR is Dominion's experimental Schedule MBR rate, which is capped at an aggregate load of 200 MW.[146]

146 "Schedule MBR - GS-4 Large General Service Primary Voltage (Experimental)," Dominion Energy. May 20, 2019, accessed January 22, 2020.

E. Wholesale Renewable Contracts

Standardized wholesale renewable contracts allow customers to contract for electricity directly with renewable developers in wholesale markets. A wholesale market is required to allow developers to connect to the transmission grid and sell electricity into the wholesale market. In these contracts, buyers negotiate a PPA directly with developers or a third-party. Customers receive fixed-price contracts for energy and/or RECs, which can allow for price hedging against future wholesale prices if the local utility provides market-based rate contracts. In return for a fixed price, developers receive revenue certainty to obtain a loan to finance the development of the renewable facility.

The majority of PPAs are financial or "virtual" in nature. That is, the electricity that a customer contracts for from a renewable facility is not directly delivered to the customer. Rather, the electricity generated by that facility is sold into the wholesale market and the customer continues to buy electricity from the local utility, either at the utility fixed rate or a time-varying wholesale rate. Customers claim the RECs produced by the renewable facility and offset their regular electricity grid purchases. The opportunity for hedging and cost savings arise when there are price discrepancies between the PPA price and the wholesale market price. If the wholesale price is lower than the PPA price, the customer settles the difference by paying the facility's developer the difference. If the wholesale price is more than the PPA price, the customer earns the difference to offset their electricity costs.

Using PPAs has gained popularity among large corporate buyers. In 2018, 22 percent of all PPAs were from corporate buyers.[147] In September 2019, Google announced a 1.6 GW renewable energy procurement that was made up of 18 separate PPAs in various countries.[148] For large-scale customers, PPA deals allow the procurement of large amounts of renewable energy and RECs to offset their local electricity purchases while also often allowing for electricity price hedging.

Negotiating a PPA requires a high level of effort and knowledge on the part of buyers, which limits its use to more experienced buyers and its scalability to expand to more customers. The contract

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147 Emma F. Merchant, "Corporate Renewables Procurement Accounted for Nearly a Quarter of All Deals in 2018," *Green Tech Media*. February 5, 2019.

148 Sundar Pichai, "Our biggest renewable energy purchase ever," Google, September 19, 2019, accessed December 27, 2019.

structure of PPAs is the underlying contract structure behind many utility subscription programs, sleeve contracts, and retail contracts, where the utility or retailer contracts for renewable energy and/or RECs with a renewable developer and then re-sells portions of the PPA to customers.

Potential exists to continue to evolve how wholesale PPAs are used to procure and distribute renewable electricity to customers. An example is the creation of volume-firming agreements where retail suppliers hedge a customer's 24-hour load by contracting for energy with PPAs from various renewable power facilities and trading energy blocks to ensure customers demand is met by renewable energy generation.[149] Services that provide volume-firming agreements can significantly ease the burden of procurement for small-scale customers and can ensure that customers' payments are resulting in constant delivery of renewable energy. This service, however, will come at a premium due to the effort required and specialized knowledge of centrally organized wholesale markets and renewable generation, in addition to having to find sufficient amount of renewable energy to shape the overall output to match the customers' consumption patterns.

F. Retail Renewable Contracts

In states with retail choice, retail suppliers can offer renewable electricity subscription services directly to customers. In Texas, retailers have provided up to 100 percent renewable energy procurement options for customers across the state. Retailers provide renewable energy through one of two methods. The first, and more common, method is that a retailer procures electricity from the grid for the customer through regular wholesale market purchases, much like a utility in a centrally organized wholesale market would, and in addition buys renewable energy credits (RECs) from renewable facilities to match customers' demand. This method leads to offerings that have premiums roughly aligned with REC price for facilities in the centrally organized wholesale market with an added premium charged for their procurement. The second method is for retailers to procure long-term PPAs with renewable facilities and then re-sells the electricity to customers. This less common method provides the opportunity for retailers to procure and trade energy to reduce electricity costs, much like customers who procure PPAs in centrally organized wholesale markets, if their procurements are lower cost than the average wholesale electricity price.

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[149] Herman K. Trabish, "New Microsoft contract could expand corporate renewable energy deals to smaller buyers," Utility Dive, November 18th, 2018.

Whether retail choice truly reduces prices below the default service is a difficult judgement to make, as this comparison (although used as a common metric) doesn't always compare similar products. Ultimately, retail providers still need to procure electricity for customers when their contracted renewable facilities are not generating and need to make a profit margin.

There are many potential benefits of retail contracts, such as that they can be streamlined to make it easy to subscribe, have relatively short-term or flexible contract lengths, and can easily be adjusted to meet customer demands. Retail suppliers have responded to customer demand for renewable energy by providing a wide variety of renewable energy products. Potential exists for retail suppliers to provide renewable volume-firming agreements to customers. Such contracts would provide 24-hour renewable power to meet customers' demand around the clock.

Another option that has emerged recently are third-party REC retailers that procure RECs nation-wide and offer any U.S. customer REC products to offset their electricity purchases. The most prominent example is Arcadia.[150] The advantage of digital REC procurement is that it allows customers in any locality and market structure to procure RECs. However, this may also result in REC procurement far away from the customer's demand, which will not physically result in the customer receiving the renewable electricity and they will not likely support new renewable generation deployment.

Appendix C: Policy Pathway Details

Policy pathways are strategic approaches that could be used to expand renewable energy procurement for C&I customers. As discussed in previous sections, barriers to procuring renewable energy vary state-by-state and are primarily determined by the electricity market structure. The policy pathways chosen in this study encompass a collection of strategies aimed to cover many market structures with varying degrees of reform, ranging from engaging with vertically-integrated utilities to providing more renewable procurement options through subscription programs to major structural changes to the electricity market. Ultimately, each is aimed at addressing current barriers limiting the ability of C&I customers to procure renewables. These include:

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150 "About Us," Arcadia, Accessed February 23, 2020.

- **Insufficient Supply of Renewable Energy:** In some states, limited renewable energy is available for contracting for C&I customers. This is most likely in states without centrally organized wholesale markets, where the incumbent utility controls the development of new resources and may not develop much, if any, new renewables.
- **Limited Access to Renewable Energy:** Even if renewables are developing, their availability for customers may also be limited by the utility. This includes capping the amount of renewables eligible for subscription programs or categorizing renewables for certain retail classes or customers, effectively limiting their availability.
- **Difficulty Procuring Available Renewables:** While renewable energy development might not be limited by market structures, such as in centrally organized wholesale market states, the ease of which a customer can procure these resources varies. Absent a subscription program, bilateral contracts (which require large amount of effort and knowledge to procure) might be the only option available, which could effectively limit the opportunities to large-scale buyers.
- **Cost of Renewable Procurement:** Lastly, the structure of renewable energy procurement options can impact the cost of the procurement. Subscriptions with high premiums, administrative costs, and long-contract lengths, in states where the underlying renewable energy might be relatively costly, limits the customers who may be interested in participating in such a program.

In the remaining section, we discuss the details of the policy pathways that are used in the analysis of policy reforms relevant for the eight sample states, which are (1) advancing state policies (i.e. RPS) that would expand mandated renewable energy purchases for jurisdictions, either for an entire utility service territory or for an entire state, (2) expanding utility subscription programs for renewable energy to enable C&I customers to procure renewables through their local utilities, and (3) introducing supply choice, (and by default, implement centrally organized wholesale markets for currently non-wholesale market states), to increase participation of wholesale and retail suppliers developing renewable energy services for all customers. Additional policy reform pathways are also discussed below for completeness but were not featured in the analysis.

The policy pathway taken by a state impacts the available renewable energy procurement options available to customers outlined in previous sections, especially if it alters the market structure of the state. Introducing a centrally organized wholesale market introduces the most options by allowing developers access to the markets and allows PPAs and procurement options derived from underlying PPAs.

A. Advancing State Policies and Utility Goals

Increasing state and utility commitments to renewable energy, either through the creation or expansion of state-level renewable portfolio standards (RPSs), emission goals, or utility goals, will increase the average amount of renewable energy on the electricity grid. While not directly procured by the customer, overall electricity demand met by renewable energy for all customers increases.

Such mandates and standards have become popular in the U.S. over the last decade with over 100 cities and states committing to 100 percent clean energy targets in the near future.[151] Part of this popularity arises from the advantage of encouraging increased state utility goals from the perspective of political feasibility. There is greater political support for increased investment and higher emissions standards than there is for a carbon tax, with 59 percent of voters approving of the former.[152] Targets also vary in whether they are for renewable energy only or all emission-free energy technologies and whether they are voluntary goals or legally-binding mandates. This allows states more flexibility to set targets, whether it through executive orders or legislation. Just recently, Virginia increased its renewable clean energy target to 100 percent by an executive order by the state Governor.[153] Table 33 summarizes the 100 percent targets for U.S. states.

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151 "100% Commitments in Cities, Counties, and States," Sierra Club, 2019, accessed January 21, 2020.

152 Sean McElwee and John Ray, "June 2019 presidential primary polling and general election implications," Data for Progress, 2019, accessed January 21, 2020.

153 Morehouse, 2019.

Table 33
Summary of 100% State Goals

State	Mechanism	Goal or Mandate	Clean or Renewable Only
California	Legislation	Mandate	Clean
Connecticut	Executive Order	Goal	Clean
D.C.	Legislation	Mandate	Renewable Only
Hawaii	Legislation	Mandate	Renewable Only
Maine	Legislation	Mandate	Clean
Nevada	Legislation	Goal	Clean
New Jersey	Executive Order	Goal	Clean
New Mexico	Legislation	Mandate	Clean
New York	Legislation	Mandate	Clean
Puerto Rico	Legislation	Mandate	Renewable Only
Virginia	Executive Order	Goal	Clean
Washington	Legislation	Mandate	Clean
Wisconsin	Executive Order	Goal	Clean

Source: UCLA Luskin Center for Innovation.

In addition to government mandates, utilities have started to take a lead in announcing targets for decarbonization. In 2018, Xcel Energy became the first large utility to commit to 100 percent clean energy and several utilities are starting to follow suit. To date, Avista, Duke Energy, Green Mountain Power, Idaho Power, and Public Service Co. of New Mexico have also set 100 percent clean energy targets.[154] Moreover, state goals, particularly within the framework of an RPS, can drive utilities to procure larger amounts of renewables and exceed the compliance requirements set by states. In California, which has a state RPS goal of 50 percent renewable energy by 2025, the state's three investor-owned utilities—Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric—have already exceeded yearly RPS goals.

To simplify political messaging and gain stakeholder support, state-level standards are often designed as one-size-fits-all policies. This can lead to compromises that may impede the development of the most efficient market for RE procurement. Examples include limiting the technologies that can compete in the REC markets to only wind and solar, at the exclusion of other

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[154] Pyper, 2019.

options such as nuclear, hydro, and others. In addition, state policies have recently become subject to mitigating federal policies that might impact their overall development. As an example, FERC recently issued an order in which it directed PJM to mitigate state-level renewable mandate policies in the capacity market.[155]

While increasing the overall percentage of electricity generated from renewable resources, mandates do not themselves create mechanisms for increasing customer renewable energy procurement options. States with aggressive targets, such as D.C.'s 100 percent goal by 2032, might satisfy customers' ambitions. However, states with lower or more far off goals leave customers demanding additional procurement options to decarbonize their own operations at a more ambitious pace. In addition, mandates will not in and of themselves address the broader structural impediments to efficient renewable procurement and integration, such as a lack of access to centrally organized wholesale markets, a lack of supply choice, or restrictive tariff terms.

B. Expanding Utility Subscription Programs

Creating or expanding utility subscription programs increases the availability of renewable procurement products for customers and can lower costs of procurements. For utilities who already have renewable programs, one of the most straightforwardly, effective measures that utilities can take to increase buyer access is lifting enrollment caps or reopening participation in green tariff and other renewable energy programs. In California, for example, the state's Green Tariff-Shared Renewables (GTSR) program has a 600 MW statewide cap, shared between three investor-owned utilities, while in Georgia, Georgia Power's Commercial and Industrial Renewable Energy Development (C&I REDI) program is fully subscribed. Raising caps and reopening enrollment in programs like these will directly increase the ability of buyers to procure renewable energy without having to develop new programs. Most recently, Georgia Power has done just this. In their recent IRP, Georgia Power has expanded their C&I REDI program with the new Customer Renewable Supply Procurement (CRSP) program with an additional 950 MW of utility scale resources.

155 Sonal Patel, "The significance of FERC's recent PJM MOPR Order explained," *Power Magazine*, December 26, 2019.

Additional improvements to utility subscription programs include decreasing subscription length to provide flexibility for customers, ensuring the program supports the development of new renewables rather than simply providing a subsidy to existing renewables, and designing the tariff to provide opportunities for customers to reduce the costs of the premium of the program. As discussed above, avoided cost-based tariffs allow for a fair representation of the costs and value of a renewable resource to the utility.

However, creating or improving utility subscription programs can take time, and the introduction or modification of tariffs requires significant input and approval from a number of stakeholders, especially state public utility commissions. Part of the challenge is addressing any concerns of costs associated with stranded assets, which may arise if new renewables limit the value of older generation sources. Lastly, the introduction or expansion of existing tariffs will not by themselves address structural limits on the amount of renewable energy development or the system's capacity to support increased renewable integration, especially when contrast with an introduction of a centrally organized wholesale market.

Nonetheless, utility subscription options provide a direct customer procurement options which can be designed and tailored to meet the needs of customers. In comparison to other pathways, such as introducing a centrally organized wholesale market or providing supply choice to allow for retail options, creating or improving utility programs might be a less arduous pathway for the short-term time frame.

C. Introducing Supply Choice to C&I Customers

Providing supply choice to C&I customers expands access of renewable retail products and enables cost-effective renewable energy procurement by opening the retail market to participation by a wider range of sellers, removing the limitation of the utility as the sole option to provide a retail renewable energy service. The competition enabled by supply choice, often in concert with the existence or implementation of a centrally organized wholesale market, can drive down the price of renewable energy products as market forces drive down administrative costs.

Providing supply choice to C&I customers can also result in greater price certainty for customers if retailers are willing to take the risks and hedge them accordingly over longer contracts, though that has not always been the case historically. Retailers are still exposed to wholesale energy risks and might not always hedge accordingly. As an example, the ERCOT energy price surges during the summer of 2019 may have negatively impacted retailers.[156] However, supply choice also introduces price risks to customers relative to regulated utility rates.[157] (NREL, 2017)

The adoption of full retail choice, however, may be the most challenging policy pathway compared to working with utilities to create subscription programs or expanding state renewable mandates. Utilities may have concerns with introducing a retail market as it directly impacts their existing customer base and planning processes. Moreover, retailers have recently received some scrutiny on their billing, pricing, and marketing practices,[158] and cost advantages have not been clear given historical data, all of which may limit stakeholder consensus on retail choice.

Nonetheless, providing supply choice to C&I customers who are located in a centrally organized wholesale market opens up access to customers and provides the most competitive structure to drive down costs of renewable energy procurement while also allowing the most renewable energy procurement options to exist. In order to meet customer demands for new renewable, retailers are expected to bear or hedge the risk of contracts that truly lead to new renewable development and be transparent about their procurement process to customers.

a. Participating in Centrally Organized Wholesale Energy Market

Utilities' participation in a centrally organized wholesale energy market can greatly impact the ability for renewable energy to be developed, the renewable procurement options available, and the ability for the system to integrate more renewable energy. A centrally organized wholesale market eases the procurement of renewable energy across state lines by providing a broader market for renewable energy, encouraging utilities and merchant generators to invest in expanded renewable generation capacity. Additionally, centrally organized wholesale markets enable

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156 "Analysis: ERCOT's price surge may have hurt some retail electricity provides: experts," S&P Global Platts, August 16, 2019, accessed January 21, 2020.

157 "An introduction to retail electricity choice in the United States," National Renewable Energy Laboratory, August 2017, accessed January 21, 2020.

158 Graves et al., 2018.

market forces that both lower the cost of energy and edge out expensive, nonrenewable generation sources like coal plants.

Utilities' participation in centrally organized wholesale markets provide a centrally competitive approach to procure new renewables at least-cost. It also introduces the market structure necessary for additional C&I procurement options, such as sleeve-contracts, potential new policies, such as a forward clean energy market, and paves the way for providing supply choice to C&I customers.

Despite substantial long-term benefits, building consensus to support organized wholesale market membership can be challenging. The immediate changes resulting from organized wholesale market membership can entail shifts in governance of transmission systems, changes to how transmission costs are allocated, and the associated financial impacts on utilities. Many state-level stakeholders are reticent to join centrally organized wholesale markets because they perceive that participation will entail a loss of control over transmission and electric power planning and surrender decision-making authority in these areas to RTO or ISO boards of directors. Control over transmission and its costs is a significant source of reticence on the part of states and utilities considering organized wholesale market membership. Joining a centrally organized wholesale market could bring with it some initial costs, particularly as local utilities begin to share transmission costs with other market participants. While the long-term benefits of centrally organized wholesale market membership are substantial and well documented, the immediate costs of membership can cause skepticism on the part of some stakeholders.

Wholesale market membership also faces resistance from utilities concerned about the impact of market membership on their ability to recover stranded costs from older or less competitive generating plants. In an electricity sector landscape with increasing renewables penetration, centrally organized wholesale market membership can accelerate the crowding out of coal and other fossil fuel–emitting plants. This leaves utilities with the decision of how to handle the cost of retiring old plants and the implications of ending associated coal or natural gas supply contracts. The political challenges associated with plant retirement also encompass questions of how to handle job losses due to closures, a salient issue for state and local politicians. Overcoming these and other challenges to participating in centrally organized wholesale markets will require a committed process of stakeholder engagement and advocacy by any group seeking to promote the adoption of an organized wholesale market.

Nonetheless, utilities and states are increasingly realizing the benefits of centrally organized wholesale markets. An example of a recent process of joining a market is Colorado utilities' decision to join California ISO's Western Energy Imbalance Market to improve renewable integration and cut customer costs.[159] Additional opportunities exist, a recent Brattle study estimates that Duke's North Carolina customers could see up to $600 million a year in benefits from participation in a centrally organized wholesale market.[160]

D. Other Policy Pathways

In addition to the policy pathways discussed above, which are the focus of the analysis, we review several additional policy pathways for completeness. The decision not to include these pathways in the analysis reflects the focus on state-level scope. The additional policies reviewed are focused on broad clean energy and emission policies that require inter-state analysis to quantify opportunities and benefits. Nonetheless, they should be considered supplemental policies that could complement the policy pathways reviewed above.

1. Introducing Forward Clean Energy Markets

A forward clean energy market (FCEM) is a regional forward auction for the clean attribute of electricity production. The FCEM differs from carbon cap-and-trade in that it will pay clean energy resources for producing energy and displacing fossil generation (rather than charging carbon emitters for their pollution). Ultimately, the FCEM provides a flexible and technology-neutral auction for renewable energy creating incentives for generators to pursue the renewable generation technologies that best serve customers' needs, including C&I customers. The FCEM also addresses many C&I customers' desire to move beyond the model of the virtual PPA, as the FCEM can be designed for manageable contract lengths. More details regarding FCEM design can be found in a recent Brattle-authored paper.[161]

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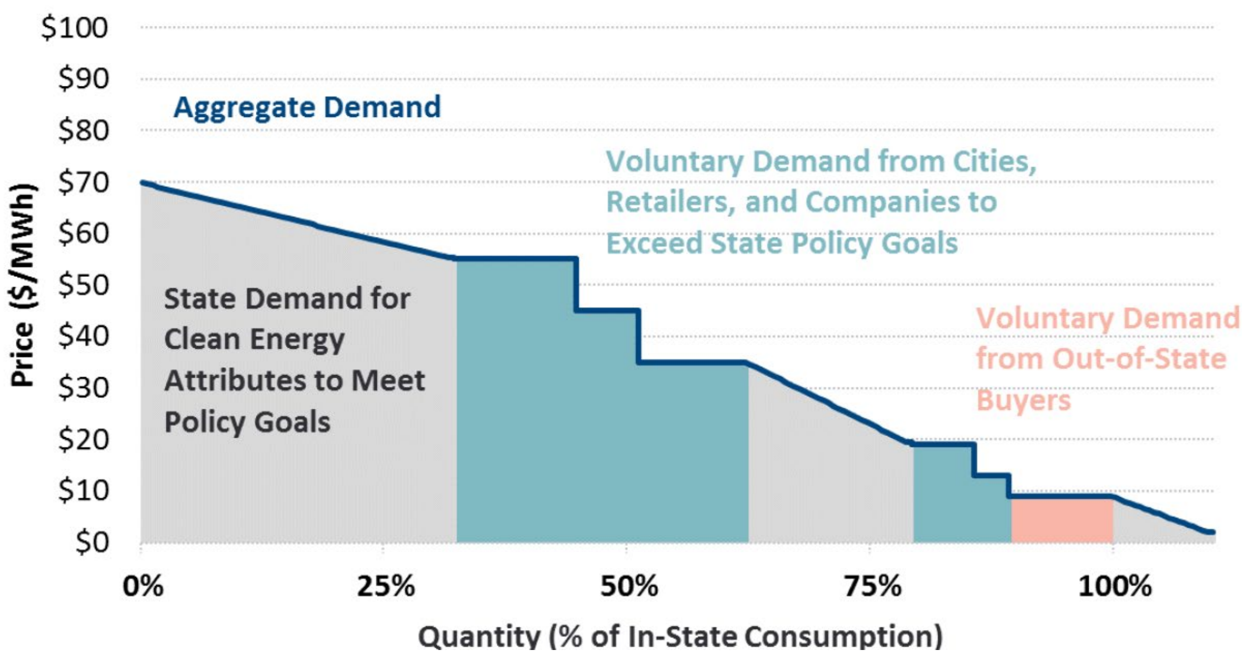
159 Robert Walton, "Xcel, 3 other Colorado utilities choose California's imbalance market over Southwest Power Pool," UtilityDive, December 18, 2019, accessed January 21, 2020.

160 Judy Chang, Johannes Pfeifenberger, and John Tsoukalis, "Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers," The Brattle Group, April 2019.

161 Kathleen Spees, Samuel A. Newell, Walter Graf, and Emily Shorin, "How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals," The Brattle Group for NRG, September 2019.

A forward auction, which occurs three years in advance of the delivery period, would bring together market participants on the supply and demand side of the market. State policymakers would mandate a quantity of carbon-free power that they wish to procure for all customers by a given delivery year. The state's mandated Clean Energy Standard becomes the minimum quantity of carbon-free electricity, while allowing for easy and cost-effective over-achievement, particularly to meet the needs of customers who would prefer to buy more than the percentage of clean energy contained in the state mandates. Specifically, the FCEM provides a platform that allows private parties to buy carbon-free power over and above the state mandates. This allows companies, municipalities, public power entities, retail electric providers, and others to exceed the clean energy standard in a cost-effective manner and with minimal overhead costs. Each participant would translate its policy or corporate sustainability goals into a quantity of clean energy, and bid for this quantity in the FCEM (Figure 35). This allows states and customers to control their future and to procure the quantity of clean energy resources that match their policy goals.

Figure 35
Aggregate Demand for Clean Energy Attribute Credits

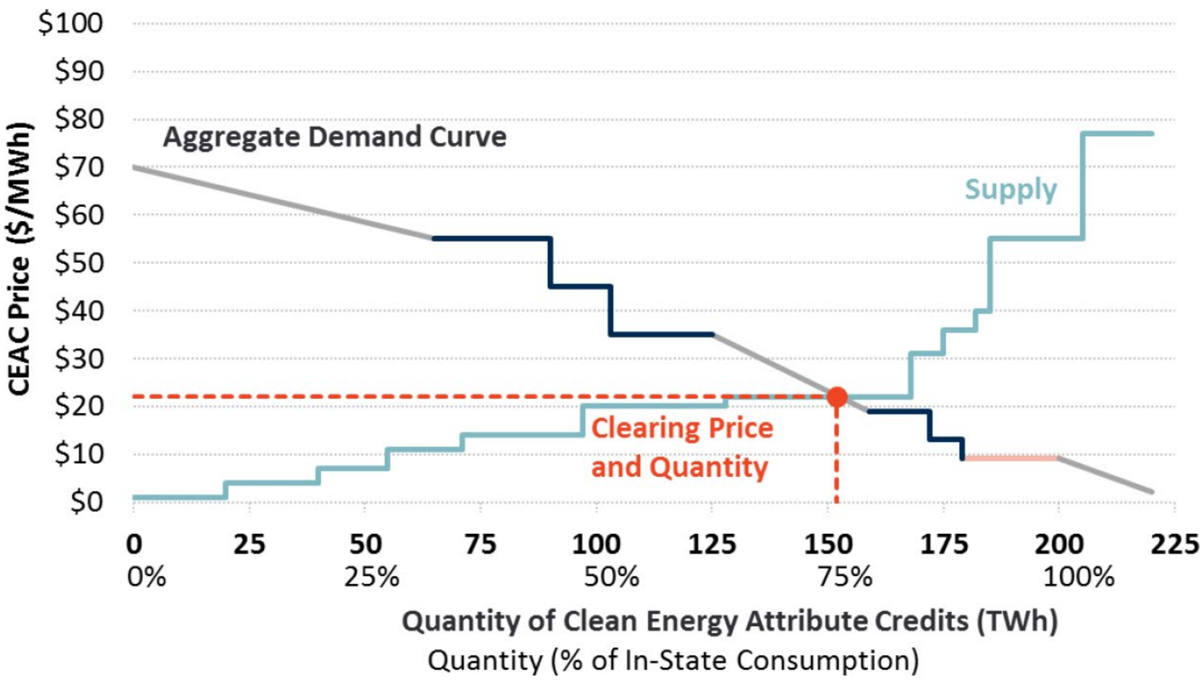


Source: The Brattle Group.

On the supply side, resources would offer in their estimated clean generation capability at a specified price for the delivery period. As the market is designed to be competitive, offer prices should reflect sellers' costs of clean generation, including going-forward costs of being online in the delivery year. Sellers whose resources are also valuable for providing energy, capacity, or ancillary services could offer at low prices into the FCEM because the large majority of the resource's costs will already be paid for by revenues from other wholesale electricity markets. The uniform-price auction would attract and reward the most cost-effective resources. More expensive options would not be selected.

Aggregate market supply and demand would be cleared in a single-price auction as depicted in Figure 35. For bids won by state entities, the costs and associated clean energy attribute credits (CEACs) would be passed through to the retail providers within that state. Other participants including private companies, municipal utilities, electric cooperatives, and retail providers could submit voluntary bids to procure additional clean energy. These participants could use their cleared bids to meet corporate sustainability goals or to offer green energy rates to end use customers.

Figure 36
Example of the Clearing of the Forward Clean Energy Market



Source: The Brattle Group.

The FCEM proposal is built around three core ideas. The first is competition, which is critical for identifying the least-cost solutions to a problem this big and with such varied possible solutions. The FCEM ensures broad competition across carbon-free energy sources and technologies. The one downside compared to a carbon price is it does not incentivize the substitution of relatively low-emitting natural gas generation for higher-emitting coal generation. The second is smart product design, where the marketable product is a CEAC, which is a certificate for 1 MWh of clean energy attributes, not including the energy itself. A marketable product reflecting just the clean energy attributes perfectly complements existing wholesale electricity markets. This allows the combined markets to find the least cost combination of technologies to meet traditional system needs while decarbonizing the grid. Traditional system needs are already rewarded through existing centrally organized wholesale markets (for energy, capacity, and ancillary services), while the policy requirement to decarbonize will be rewarded through the new market (for clean energy attributes). The FCEM also allows customers to submit their own "bids" that reflect their willingness to pay for renewable energy resources, capping the higher end of the cost range. In all, the centrally organized wholesale markets and the FCEM can ensure that both system reliability and decarbonization targets are achieved at the lowest possible cost. The third core idea is multi-year forward procurement, using an auction design and the opportunity for multi-year price lock-in for new resources. This approach has proven successful in supporting financing for new power sector investments. Moreover, the moderate commitment and forward periods are short enough to respond to changes in market conditions and leave the burden of technology and market fundamental risks with developers and investors, who are best equipped to assess fundamentals and risks and invest accordingly.

Implementing a FCEM will require the establishment of an agency or authority to regulate trading within the market, which represents an initial investment of time, effort, and funds. Additionally, establishing a FCEM within a wholesale electricity market requires regulatory approval from all states with territory participating in the centrally organized wholesale market. While this might be a relatively straightforward for a single-state market like NYISO, coordinating state-level approvals in markets with a wider geographic area like MISO or PJM might prove more challenging and require a lot of effort to drive stakeholder consensus. Furthermore, because FCEMs are still an attributes market, they do not immediately address buyers' goals of moving beyond trading in attributes or credits and into a fully green grid in the U.S.

2. Including Carbon Pricing in Centrally Organized Wholesale Markets

Carbon pricing policy applies a cost for emitting greenhouse gas emissions into the atmosphere. In economic terms, carbon pricing internalizes the externalities associated with carbon emissions.

Placing a cost on emissions shifts the economics of electricity generation towards non-emitting technologies. Economics often favor carbon pricing because its design promotes cost-effective abatement through market forces and can ameliorate, rather than exacerbate, government fiscal problems.[162] By pricing emissions, governments defer to private firms and individuals to find the lowest cost ways to reduce emissions. In this section, we discuss two carbon pricing designs: carbon taxes and cap-and-trade.

Often argued as the simplest approach, a carbon tax places a dollars per ton of emission charge on greenhouse gas emissions. To be cost-effective, the carbon tax would be set equal to the marginal benefits of emission reduction, represented by estimates of the social cost of carbon. A carbon tax provides certainty about the marginal cost of compliance, which reduces uncertainty about returns to investment decisions, but leaves uncertainty on how much emission reductions occur.

In wholesale electricity markets, a carbon price can alter the economics of short-run marginal costs of production to favor clean resources. Fossil resources face production-based tax on their marginal emission rates, which increase the price that these generators bid into the electricity market. Moreover, a carbon tax favors more efficient fossil generators, shifting generation from coal to natural gas. It is estimated that a $25 and 50$ per ton of carbon dioxide tax results in 17 percent and 22 percent reduction in electricity generation emissions across the U.S. in the short-run, mostly from lower use of coal generation in the Mid-Atlantic, Midwest, and Western states.[163] In New York, a study found that a $40 per ton carbon charge would provide 8 percent emission reductions and raise wholesale prices by $19/MWh.[164] In the medium- and long-term, however, a $50/MWh tax drives investment in renewable energy and is estimated to result in up to 60 percent emission reductions.[165]

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162 Joseph E. Aldy and Robert N. Stavins,"The Promise and Problems of Pricing Carbon: Theory and Experience" *Journal of Environment & Development* 21(2012): 152–180.

163 Steve Dahlke, "Short Run effects of carbon policy on U.S. electricity markets" *Energies* 12(2019): 2150.

164 Samuel A. Newell, Roger Lueken, Jürgen Weiss, Kathleen Spees, Pearl Don "Pricing Carbon into NYISO's Wholesale Energy Market to support New York's Decarbonization Goals". The Brattle Group. August 10, 2017.

165 John Larsen, Shashank Mohan, Peter Masters, and Whitney Herndon,. "Energy and environmental implications of a carbon tax in the United States," Center on Global Energy Policy, July 2018, accessed January 21, 2020.

Despite its economic efficiency, implementing a carbon tax is a difficult task. The two main challenges to driving a consensus on a carbon tax design that often arise are agreeing upon the appropriate carbon tax amount and determining the use of the tax revenue. The level of tax is often based on an estimate of the social cost of carbon, the costs of emitting one ton of greenhouse gas emissions. This value is often debated as estimates of the social cost of carbon are subject to many assumptions in integrated assessment models, such as discount rate, model version, and inherent uncertainties in climate models.[166] This can lead to implementation of a carbon tax that is too low to drive significant emission reductions. For example, the Canadian province of British Columbia has had a carbon tax in place since 2008. However, the low tax rate and the fact that most of the electricity generation in British Columbia is hydroelectric and therefore carbon emission-free, has only reduced emissions by five to 15 percent.[167] Studies investigating deep decarbonization of the electricity sector suggest very high implicit costs once emission reductions are nearing high levels.[168, 169] As such, carbon taxes would also have to increase to continue to drive emission reductions, increasing the political challenge of implementing a new tax.

In addition, there is much debate among politicians about the use of revenues gathered from the implementation of the tax. Despite having political support for the introduction of a carbon tax, Initiative 732 in Washington State suffered defeat in part from a rift in opinion about the usage of the revenue accumulated from a carbon tax.[170]

Cap-and-trade policies, in contrast, constrain the aggregate emissions by creating a limited number of tradeable emission allowances that sum to the overall cap. This implicitly creates a cost of compliance through trading of allowances, which prices carbon emissions. The tradeoff of a cap-and-trade policy to a carbon tax is that the former provides emission reduction certainty but not cost certainty, like the latter. This can be problematic from the perspective of investment decisions, which prefer a certain forecast of economic conditions into the future. Similar to carbon taxes,

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166 "Q&A: The social cost of carbon," Carbon Brief, February 14, 2017, accessed January 21, 2020.

167 Brian Murray and Nicholas Rivers, "British Columbia's revenue-neutral carbon tax: A review of the latest "grand experiment" in environmental policy," *Energy Policy* 86(2016): 674–683.

168 Sepulveda et al., 2018.

169 Daniel Shawhan, Paul Picciano, and Karen Palmer, "Benefits and Costs of Power Plant Carbon Emissions Pricing in New York: Overview and Summary," *Resources for the Future,* July 2019, accessed January 21, 2020.

170 David Roberts, "The left vs. a carbon tax," *Vox*, November 8, 2016, accessed January 21, 2020.

cap-and-trade policies face many challenges to get implemented, such debates about the level of the emissions cap and possible exclusion of industries deemed too politically sensitive to burden with a carbon price. The results can lead to an ineffective system, such as the European Union Emission Trading System, which has been accused of allocating too many allowances that have resulted in low prices.[171]

The benefits of a carbon price, however, remain clear and robust. Carbon pricing can shift both short- and long-run economics to favor lower emitting resources and drive emission reductions. Moreover, the market-nature design of carbon pricing policies can use market forces and a diverse set of technologies to drive down costs of reduction emissions substantially. Including non-renewable non-emitting resources can help reduce costs by 10-62 percent at deep decarbonization levels.[172] While these policies do lead to more development of renewables, carbon pricing policies do not increase the clean energy procurement options for C&I customers who want to drive their own emissions down. Additional policy reforms would be needed to allow more customers to procure their own renewable resources in order to meet corporate commitments/goals.

3. Federal Clean Energy Standard

A federal clean energy standard (FCES) is a mandate for clean energy procurement that is applied across the entire U.S. Similar to state-level clean energy mandates, a FCES mandates that a specific amount of clean energy is procured nationally, often through the procurement of tradeable clean energy credits. A FCES gained much attention in 2011, when President Barack Obama called for a FCES of 80 percent by 2035. While several FCES designs have been proposed both before and after this address, none have been adopted. Although this report focuses on state-level policy pathways and does not consider analysis on a FCES, the policy is reviewed in this section for completeness.

While specific design features vary, such as uniform versus differentiated targets, the ability to bank credits, which resources qualify for credits, and more, the primary benefits of an FCES is that it provides a market-based approach across a wider range of geographies to allow trading of credits between varying renewable facilities to drive down costs. In an FCES, utilities within localities are mandated that a certain percentage of their electricity has a clean energy credit, which can be

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171 Jill Duggan, "The Truth About Cap-and-Trade in Europe," World Resources Institute, November 19, 2009.

172 Sepulveda, et al., 2018.

procured by the utility's own generation or by purchasing a credit from other clean energy generator. The use of tradable credits gives electric utilities substantial compliance flexibility since no electric utility needs to generate or deliver any specific quantity of clean energy from their own generation portfolio. In comparison to state-level mandates which often have less flexibility as utilities are required to procure credits from generators either in the same state or centrally organized wholesale market, the tradeable design of an FCES has been estimated to reduce the costs of emission abatement up to 90 percent.[173]

The most recent iteration of a FCES is the *Clean Energy Standard Act of 2019* that was introduced in the U.S. Senate in May 2018.[174] Under the Act, the national clean energy percentage mandate is 51 percent in 2021 and increases to 77 percent in 2035 and 96 percent in 2050. Implementation of the act is estimated to provide a 61 percent decrease in power emissions by 2035 with a cost estimate of $106 billion, which translates to around 4 cents per kWh.

The effectiveness of a FCES is also heavily dependent on adequate transmission to transport renewable energy from high-quality renewable localities to less-endowed regions. Numerous studies have estimated cost-savings of a national transmission grid designed to optimize the utilization of renewable energy.[175, 176, 177] It is estimated that electricity sector emissions could be reduced by up to 80 percent relative to 1990 levels if a national optimized transmission infrastructure existed.[178] Without adequate transmission between regions, the benefits of regional diversification of renewable generation are limited. Yet, development of transmission across state borders remains difficult and little long-distance transmission has been built in the U.S. This is due to difficulties allocating costs across different regions, transmission zone planning inefficiencies, and local interests opposing transmission lines in their backyards.[179]

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173 Makena Coffman, James P. Griffin, and Paul Bernstein, "An assessment of greenhouse gas emissions-weighted clean energy standards," *Energy Policy* 45(2012): 122–132.

174 Smith, T., Luján, B.R. "Clean Energy Standard Act of 2019". May 8, 2019.

175 "Interconnection Seam Study," National Renewable Energy Laboratory, accessed January 2, 2020.

176 "The benefits of a 'Transmission Superhighway," Southwest Power Pool, Accessed January 2, 2020.

177 L. Bird and M. Milligan, "Lessons from Large-Scale Renewable Energy Integration Studies," National Renewable Energy Laboratory, May 2012, accessed January 21, 2020.

178 MacDonald et al., 2016.

179 David Roberts, "We've been talking about a national grid for years. It might be time to do it." *Vox*, August, 3, 2018.

Similar to a carbon tax, passing FCES legislation requires enormous stakeholder consensus among political parties, local governments, and industry, and does not explicitly provide more customer renewable energy procurement options. Despite advantages of a FCES, national-scale climate policies have not received enough political support to become law. Notable attempts to pass legislation with a FCES-style mechanism include Senator Coleman's clean energy portfolio in 2006, the Waxman-Markey Act of 2009, and three proposals in the Senate in 2010.[180] In each case, various stakeholders opposed legislation for a variety of reasons, highlighting the difficulty of driving consensus for national climate legislation. In addition, while a FCES leads to more development of renewable energy, it is still up to the utility to provide procurement options for customers whose ambitions are greater than the standard.

180 "Clean Energy Standards: State and Federal Policy Options and Implications," Center for Climate and Energy Solutions, November 2011, accessed January 21, 2020.

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