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SUMMARY REPORT: ECONOMIC AND CLEAN ENERGY BENEFITS OF ESTABLISHING A SOUTHEAST U.S. COMPETITIVE WHOLESALE ELECTRICITY MARKET

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EXECUTIVE SUMMARY

Seven Independent System Operators (ISOs) or Regional Transmission Operators (RTOs) serve close to 70 percent of all United States electricity consumers. One region of the country, the Southeast, is particularly devoid of this type of market competition. This report details the impacts of enhancing competition for wholesale electricity transactions through a theoretical organized market in the Southeast region. We use a combined production-cost and capacity-expansion model of the electric power system in seven Southeastern states (Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina, and Tennessee) out to 2040. This Summary Report details the high-level findings, while a companion technical report details the model mechanics and scenario analysis in greater detail.[i]

We find that a competitive Southeastern RTO creates cumulative economic savings of approximately $384 billion[ii] by 2040 compared to the business-as-usual (BAU) case. In 2040, this amounts to average savings of approximately 2.5¢ per kilowatt-hour (kWh), or 29 percent in retail costs compared to BAU. 2040 retail costs in the RTO scenario are 23 percent below today's costs. In the RTO Scenario, carbon emissions fall approximately 37 percent relative to 2018 levels, and 46 percent compared to the IRP Scenario, in which emissions increase. Other major criteria pollutants impacting human health, such as NO_X, SO_2, and $PM_{2.5}$, drop dramatically,

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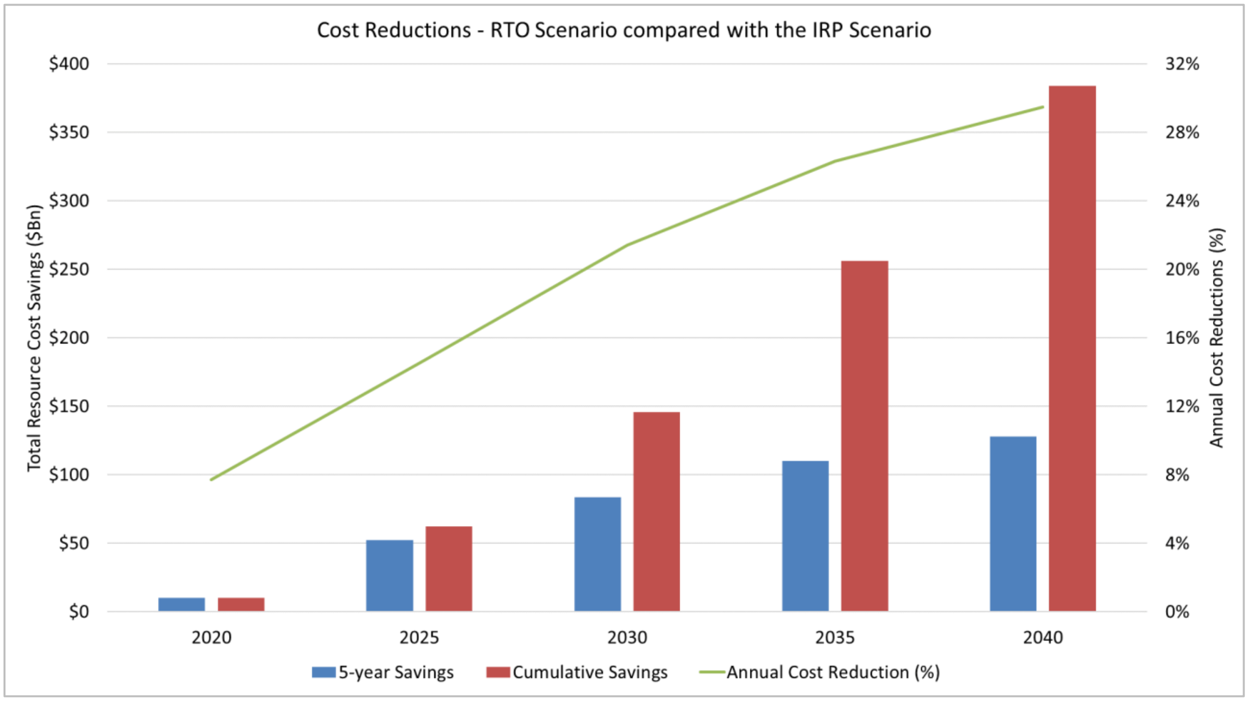
[2] GridLab https://gridlab.org/

[3] Vibrant Clean Energy https://www.vibrantcleanenergy.com/

largely as a result of eliminated coal generation. Emissions gains are driven by a vast deployment of renewable energy resources replacing coal.



Employment benefits begin accruing immediately after the RTO comes into operation, as lost jobs in coal and natural gas generation are replaced by construction jobs related to wind, solar, and battery deployment. By 2040, the RTO scenario creates 285,000 more jobs relative to the business-as-usual scenario, owing to the construction of 62 gigawatts (GW) of solar, 41 GW of onshore wind, and 46 GW of battery storage.

Our BAU case relies on the Integrated Resource Plans of the major investor-owned utilities in these states, in which utilities prescribe a coordinated set of new generating and transmission capacity necessary to meet future load projections. Vibrant Clean Energy's WIS:dom®-P model then optimizes operations for these projected resource additions and retirements based upon historical dispatch estimates, assuming no further public policy intervention. In this case, the model assumes that each utility must meet its specified load projections and planning reserve margins independently, assuming limited import/export capacity from neighboring utilities and limited transmission expansion.

We compare this scenario to a fully competitive wholesale electric market, in which an RTO-administered open market determines the most cost-effective capacity mix and resource dispatch, regardless of where that generation is located or who owns it. The RTO scenario assumes an integrated transmission planning scheme in which all seven Southeastern states share resources and expand transmission in order to meet one regional planning reserve margin at least cost. The competitive RTO Scenario modeled here grants planners and operators in the region the opportunity to co-optimize generation, distribution, and transmission benefits while planning to meet capacity in the most economically efficient way.

A companion policy report additionally details key policies to help achieve competition's benefits in the Southeast region. We focus on incremental policies that introduce competition into regional dispatch and utility resource planning and procurement. We cover principles for market design to help ensure a regional market is compatible with a cost-effective variable resource mix. We outline policies that enable regional utilities with net-zero carbon goals to meet those goals effectively while respecting and supporting the fossil-dependent communities that supported economic development in the region.

Despite the fact that new renewable energy and battery storage resources are the least-cost forms of generating electricity, the Southeast region is largely beholden to monopoly utilities that rely on existing coal fleets and new gas-fired power plants to meet consumer electricity needs. This report finds that these utilities continue to inefficiently plan the power grid at great expense to consumers. Wasted excess capacity leads to wasted consumer dollars while stifling clean energy deployment, employment gains, and public health benefits.

Policymakers considering a regional market or state-level competitive procurement should be encouraged by this analysis to keep pressing in legislative and regulatory forums. State stakeholders where utilities block competitive reforms now have new quantitative findings to challenge the assumption that the way utilities have traditionally done business is in the public's best interest.

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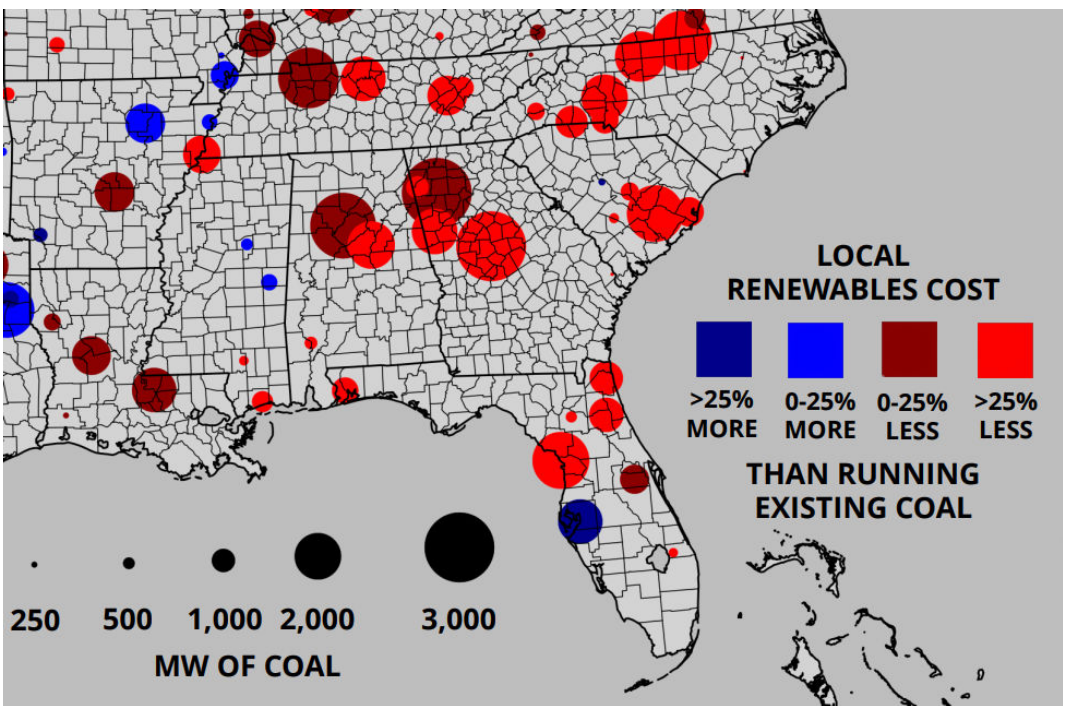
INTRODUCTION

The Southeast region of the U.S. remains one of the country's only regions without organized wholesale electricity markets (along with the West). While energy restructuring and reform swept through much of the nation in the early 2000s, this reform failed to upend the traditional vertically-integrated monopoly structure dominant in the Southeast.

In effect, Southeastern utility planning is a patchwork system dominated by monopoly utilities, in which those utilities plan their electric grids independently from their neighbors (or even subsidiaries of the same holding companies). These utilities provide power within service territories to the near-complete exclusion of competition. Further limiting competition, these utilities charge any sellers importing power to their customers a "wheeling charge," which raises the cost of outside alternatives to the benefit of the utility's generation assets. Largely insulated from meaningful forms of competition, Southeastern utilities have been among the slowest to embrace clean electricity resources, even as resource costs have fallen precipitously in recent years.

In 2019, Energy Innovation and Vibrant Clean Energy partnered to compare the cost of operating each coal plant in the U.S. against the cost of building new, local wind and solar.[iii] The simple analysis revealed that about two-thirds of existing coal plants were more expensive to continue running when compared to replacement by local wind or solar. The results for the Southeast were even more pronounced: nearly every coal plant (92 percent of existing capacity) was uneconomic compared to local wind or solar in 2018.[iv] By 2025, that number grows to 100 percent.



The Coal Cost Crossover report shows nearly every Southeastern coal plant is uneconomic compared to local wind and solar resources.

While coal and renewables provide different services and value to the grid, the presence of substantial amounts of uncompetitive coal generation and low-cost renewable alternatives led us to hypothesize that competition would yield both significantly lower costs and create opportunities for clean energy resources to rapidly enter an otherwise restricted market.

Analysis of regional co-optimization and competition also bears upon ongoing conversations around introducing competition in the region. In the Carolinas, legislators from each state have called for establishment of an RTO, which would take control of power plant and transmission operations away from the incumbent monopoly utilities and optimize them for cost.[v]

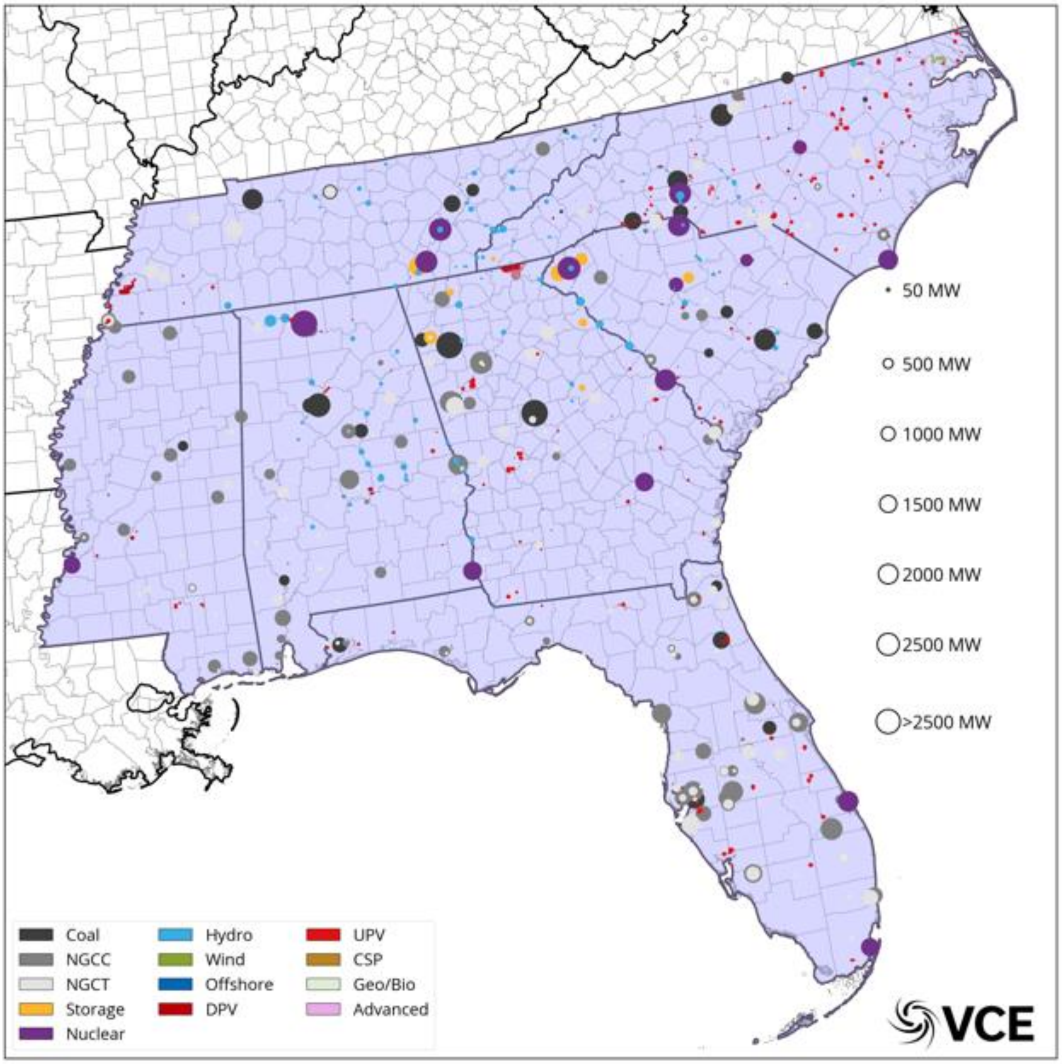
Meanwhile, the three largest utilities in the region – Duke Energy, Southern Company, and Tennessee Valley Authority (TVA), have indicated they will propose a voluntary regional energy exchange in the region to the Federal Energy Regulatory Commission (FERC).[vi] These radically different paths toward greater resource optimization and competition in the region could benefit from quantitative information to inform market design choices going forward.

THE ANALYSIS: METHODOLOGY AND SCENARIOS

To inform regionalization discussions and explore potential cost and emissions impacts of competition on the region, this study investigates the impacts of increasing competitive options for consumers using the WIS:dom®-P model (a state-of the-art energy model developed by Vibrant Clean Energy, LLC).

It is the first commercial co-optimization model of energy grids that was built from the ground up to incorporate vast volumes of data, starting with high-resolution weather and demand data. The model relentlessly seeks the least-cost solution pathway for the electricity system, incorporating up-to-date technology performance characteristics, while conforming to reserve requirements for every region in the U.S. More information about the mechanics of WIS:dom®-P is available in section three of VCE®'s companion technical report to this summary report.[vii]

This report analyzes the impacts of a Southeast competitive wholesale electricity market, similar to how ISOs or RTOs operate elsewhere around the country. Because the WIS:dom®-P model is able to adjust to different geographic scales, VCE® configured a Southeast module, allowing the model to optimize the power system across seven Southeast states: Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina, and Tennessee.



The geographic region modeled in this analysis, including generating resources currently in operation.

VCE® modeled two core scenarios and two sensitivities. The core scenarios compare a business-as-usual approach and a fully competitive regional approach. We represent the business as usual through an Integrated Resource Plan (IRP) Scenario, whereby the model builds capacity embedded in existing Southeast utility resource plans and dispatches these resources in line with historical trends or as stated in the IRPs.

Competition is represented in the Regional Transmission Organization (RTO) Scenario, which mimics a competitive wholesale market for the entirety of the Southeast region, in which the model chooses the most economically efficient resources from an open regional market, optimizes dispatch of these resources to minimize cost, and performs co-optimized transmission and distribution planning, as well as reserve sharing across the region.

Scenario	Description	Transmission Expansion	DER Coordination	Wheeling Charges
SE IRP	The individual IRPs released by utilities in the southeast states are combined and run through optimal dispatch.	Not allowed	Off	Across state lines
SE Economic IRP	Optimal capacity expansion for the southeast states without creating an RTO	Not allowed	Off	Across state lines
SE RTO	Optimal capacity expansion with an RTO setup in 2025 over the southeast region	Allowed	On	None from 2025 onwards
SE RTO with Nuclear	Optimal capacity expansion with an RTO setup in 2025 over the southeast region. Nuclear is not retired even if uneconomic.	Allowed	On	None from 2025 onwards

In the **IRP Scenario**, we stitch together the IRPs of major investor-owned utilities in the region, including Alabama Power, Duke Energy (present in the Carolinas and Florida), Florida Power and Light, Georgia Power, Mississippi Power, and TVA.[viii] The IRPs represent a 10-15 year forward looking assessment of the utilities' new and retiring capacity, load projections, and other assumptions regarding utility operations in near- to medium-term. The model uses the prescribed capacity additions included in the IRPs as a key input, and then performs a production-cost analysis[ix] to determine the total system cost over the course of the study period.

The model is beholden to the energy deployments prescribed in the plans, and thus has little opportunity to take advantage of more cost-effective resource mix alternatives or economically optimal dispatch. Additionally, each utility in the region continues to operate independently within each respective service territory, with only minimal coordination of imports and exports.

Realistically, what would emerge over time with BAU in the Southeast does not exactly match the 10-15 year IRPs, which are periodically updated. Hopefully, as utilities and their regulators catch up to the reality that clean electricity is less expensive than the status quo, it is reasonable to assume the inefficiencies won't be quite as stark as the modeling implies. Nevertheless, we model the current IRPs to demonstrate how current utility plans miss out on the potential for a clean, cheap, reliable electricity system in the region and thus open up customers to financial risk from potential stranded assets.

In contrast, the **RTO Scenario** models a competitive wholesale electricity market across all seven states[x] in which each region procures a mix of resources to reliably meet load every hour from a modeled open market, at least cost. In this scenario, the Southeast region operates with a fully open transmission network, eliminating the inefficient "rate pancaking" that exists in this region as well as other non-RTO regions.[xi]

Similarly, the model co-optimizes the transmission and distribution network in order to ensure that resources are procured and utilized in the most-efficient and cost-effective manner. The region is planned and operated as one entity, in which resources are shared broadly across an open network to meet load and a single Planning Reserve Margin, minimizing the inefficiencies associated with meeting load on a state by state basis in the IRP Scenario. However, the new RTO does not optimize transmission and dispatch with adjacent grid operators PJM Interconnection and Midcontinent Independent System Operator (MISO).

The RTO Scenario developed by VCE® will certainly diverge from a real-world regional wholesale electricity market. Each competitive energy market in the U.S. has a different design that impacts where money flows and who bears the risks of competition. For example, some markets allow vertically integrated monopolies to continue recovering costs of generation from captive customers, while others require all generators to be independent of the poles and wires companies. RTOs today also face structural and political barriers to transmission development and fair cost allocation, distribution optimization, and clean or distributed energy resource participation, each of which are optimized seamlessly in WIS:dom®-P.

As such, the RTO Scenario represents a maximum for the benefits of competition in the region, as contrasted with the uncompetitive IRP Scenario.

We model two additional scenarios to evaluate the impact of deviations from the scenarios described above: An **Economic IRP Scenario** and an **RTO with Nuclear Scenario**. The Economic IRP Scenario allows the model to choose a cost-optimal resource mix, but does not include the co-optimized transmission and reliability planning present in the RTO Scenario. It maintains existing balancing area authorities; therefore, it represents a competitive procurement process within existing monopoly service territories, without exposing these utilities to regional competition or taking advantage of reserve sharing. The RTO with Nuclear Scenario is equivalent to the RTO Scenario, except that this scenario assumes that all existing nuclear plants licenses are extended, and the nuclear plants remain operational through the end of the study period.[xii]

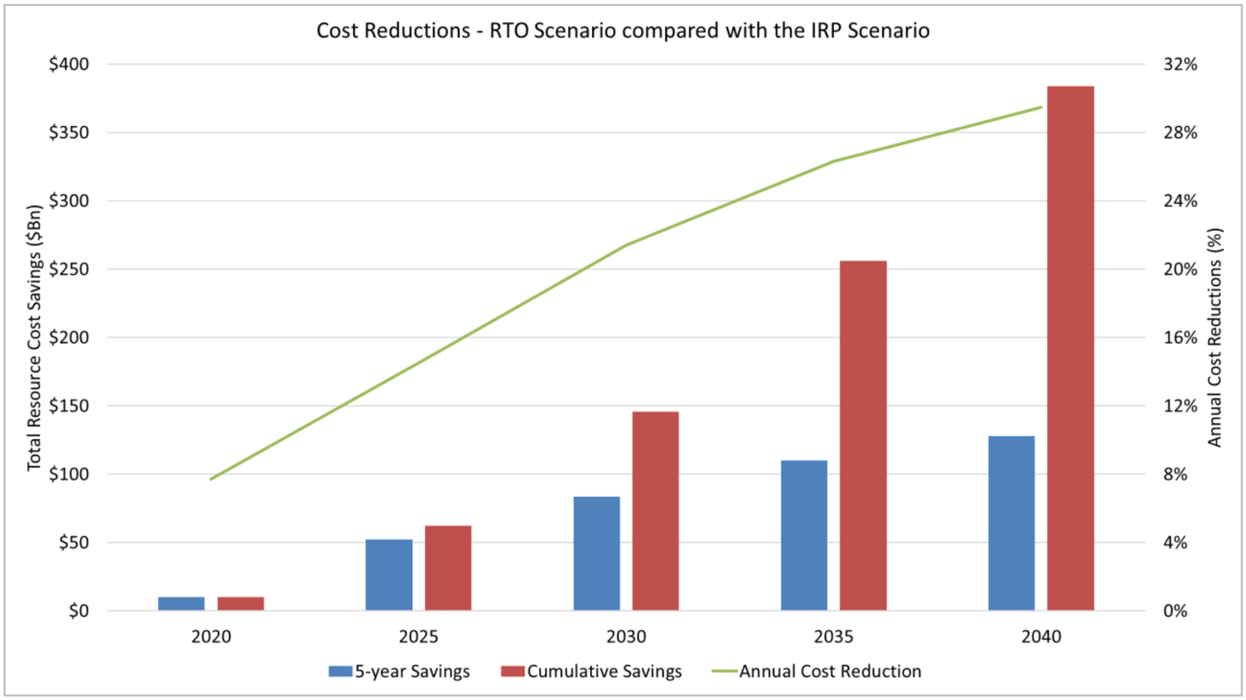
This Summary Report focuses on the core scenarios, with occasional reference to the sensitivity scenarios.

THE RESULT: COMPETITION WOULD DRAMATICALLY LOWER COSTS FOR ELECTRICITY CUSTOMERS, CREATE JOBS

COST SAVINGS

The effects of a single restructured wholesale market in the Southeast are dramatic and immediate. In 2025, the year in which the model has fully operationalized the competitive electricity market, the RTO Scenario is approximately $13 billion cheaper in operations and amortized capital costs. By 2040, the cumulative savings of the RTO Scenario is approximately $384 billion, as expensive-to-run coal and gas fired power plants are replaced with more competitive wind, solar, and battery storage.

These savings translate to 2.5¢/kWh lower rates in the RTO Scenario by 2040 compared to the IRP Scenario, a 29 percent reduction. The savings can be largely attributed to a leaner, cheaper mix of capital and fuel expenses that take advantage of more efficient system operations.[xiii]



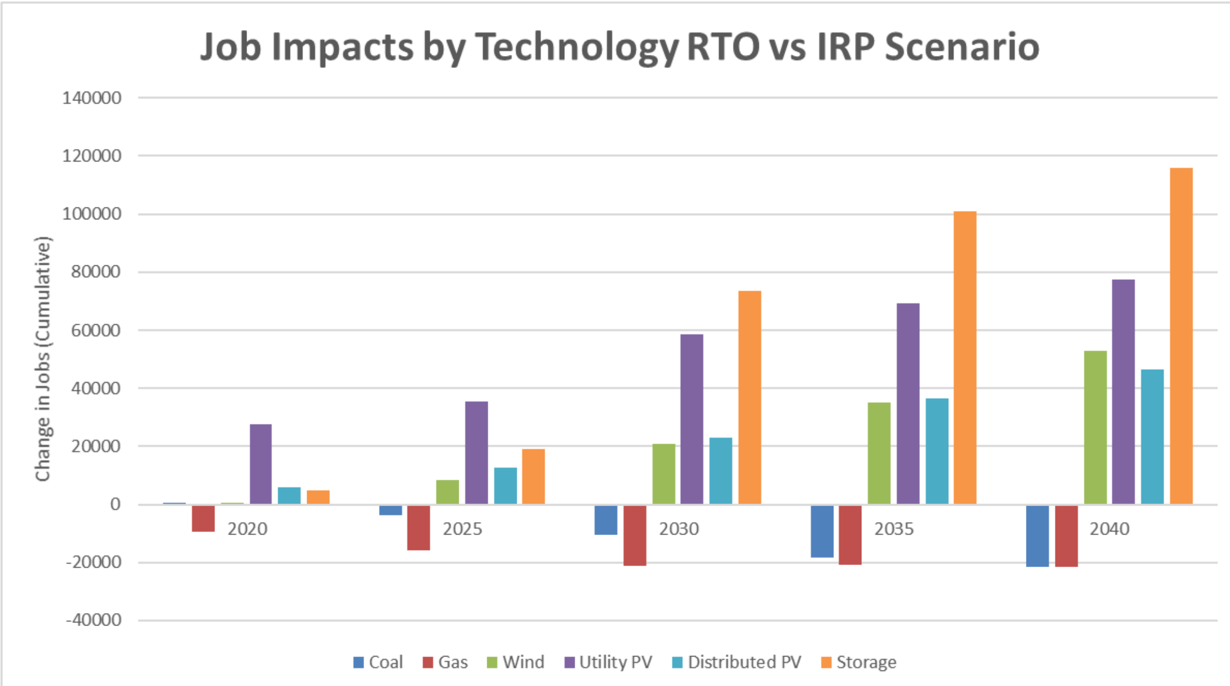
The RTO Scenario savings reflect improvements on the inefficiencies of a balkanized, uncompetitive approach to transmission planning, resource adequacy, integration of distributed energy resources, and dispatch throughout the region. Regional transmission planning through an RTO rationalizes transmission planning to reduce congestion and expose more expensive plants in load pockets to competition. It improves dispatch economics throughout the region. It allows resource sharing and efficient procurement of capacity to maintain reliability. It also accelerates displacement of uneconomic coal generation with cost-effective clean electricity resources, primarily wind, solar, and low-cost storage options, reducing system costs in each investment period.

Approximately 10 percent of cumulative savings, or $38 billion, is attributed to distribution system savings, as co-optimized distribution system planning reduces redundant investments. In the RTO Scenario, the model encourages behind-the-meter generation and storage when it reduces total system costs, including distribution infrastructure costs.

This co-optimization of bulk and small-scale resources helps reduce peak load in the RTO Scenario 11.8 percent below the IRP Scenario, creating savings from generation all the way down to distribution. Realizing these savings goes beyond reforming the market structure for the bulk power system, and likely requires regulatory incentives at the distribution level to coordinate with a central RTO, as discussed in the policy recommendation section below.

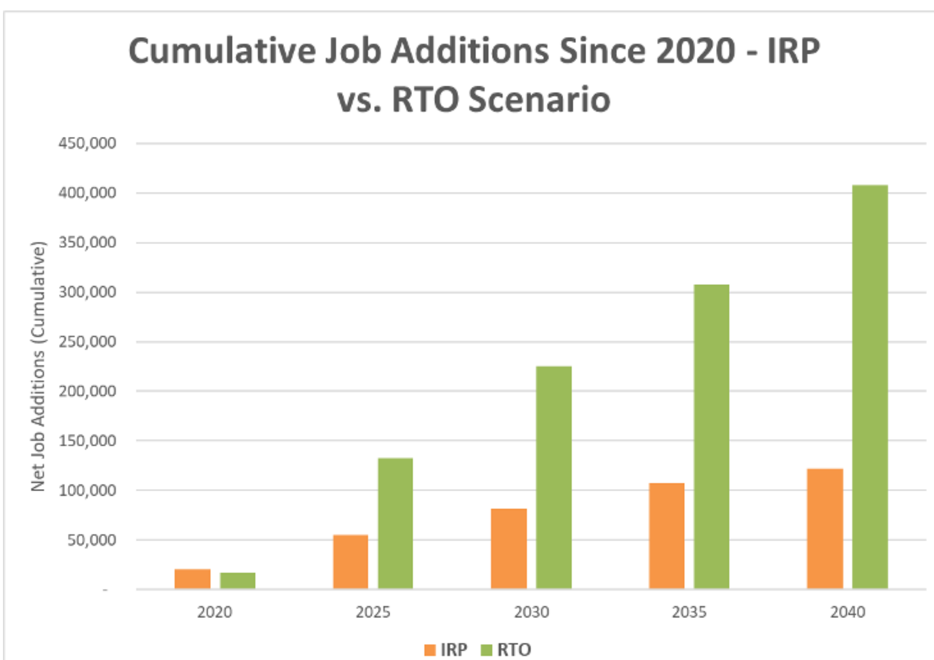
MARKET COMPETITION ACCELERATES JOB CREATION

The dramatic shift in electric power generation has significant employment impacts across the region. In both scenarios, electric sector investment leads to an increase in jobs through 2040. The RTO Scenario sees new jobs highly concentrated in cost-effective clean technologies like solar, wind, and storage.



Cumulative Change in Electric Sector Jobs by Technology Type in RTO Scenario Versus IRP Scenario 2020-2040.

The IRP Scenario also sees job growth, in part as an artifact of the inefficiency of the system. With a reserve margin over 40 percent, the IRP Scenario is significantly overbuilt, leading to more jobs in unnecessary and expensive coal and gas plants. Despite this, the IRP Scenario immediately starts lagging the RTO Scenario in job creation once the market is fully operational (2025). Overall, by 2040, the RTO Scenario leads to an additional 408,000 jobs in the sector, compared to just 122,000 new jobs in the IRP Scenario, a net of 285,000 jobs.[xiv]



Cumulative Electric Sector Jobs Added in IRP and RTO Scenarios by Investment Period, 2020-2040.

By 2040, the RTO Scenario includes 55,000 jobs in wind, 282,000 jobs in solar, and 142,000 jobs in storage, compared to just 2,700 wind, 126,000 solar, and 26,000 storage jobs in the IRP Scenario. But the build-out and associated jobs could be more significant, especially in the later years of the analysis as the industry scales. WIS:dom®-P limits the wind and solar power build out to track historical capacity expansion of these resources.[xv]

Efforts to ramp up renewable energy deployment in the immediate future may bring additional employment and cost savings benefits to the region by expanding deployment capacity, or bringing manufacturing jobs to the region. As such, the RTO Scenario represents a somewhat conservative technical analysis of renewable energy's possible contribution to both jobs and a future competitive electric system in the Southeast.[xvi]

VCE®'s jobs analysis does not consider knock-on effects of reduced electricity rates on the region's industrial competitiveness or additional consumer and business spending unlocked by the savings. Electricity rates that are 2.5¢/kWh lower by 2040 would further enhance the region's already low rates and attractiveness to industry.

An additional benefit of an organized wholesale market would be direct access to least cost renewable electricity, an attractive proposition for large corporations increasingly concerned with reducing their impact on climate change.

EMISSIONS IMPACT

The RTO Scenario dramatically reduces carbon emissions and virtually eliminates many major air pollutants (through the phase-out of coal), resulting in significant benefits to human health. Compared with the IRP Scenario, carbon dioxide (CO_2) emissions in the RTO Scenario are 46 percent lower in 2040.

Compared to 2018 levels, CO_2 emissions are 37 percent lower in 2040. In the IRP Scenario, CO_2 emissions increase due to an expansion of the electric grid, largely buoyed by additional gas investments. Major criteria air pollutants, including $PM_{2.5}$, PM_{10}, and SO_2 all drop to near-zero in 2040

Emissions Goals for Southeastern U.S. Utilities: Spotlight on Duke Energy and Southern Company

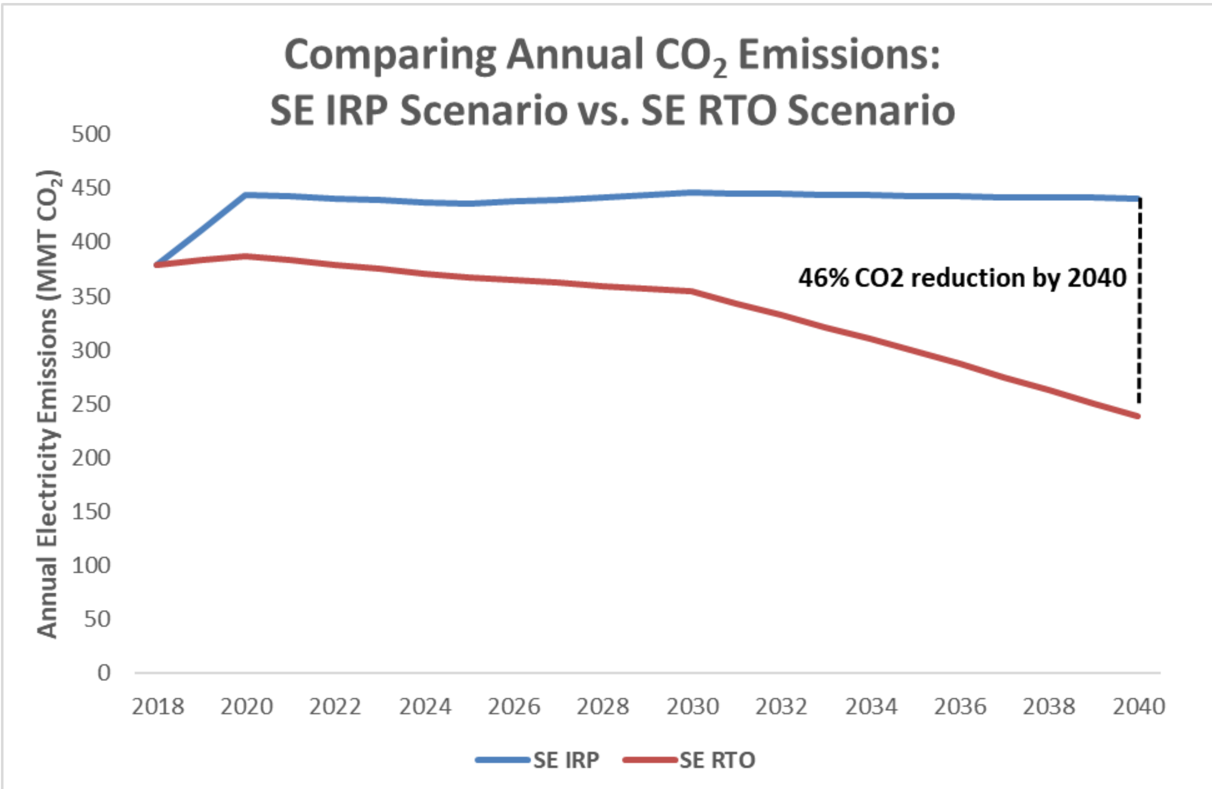
Both Duke Energy and Southern Company have pledged to achieve net-zero company emissions by 2050, an aspirational goal in line with the goals of the Paris Agreement target to keep global warming below 1.5° Celsius. Yet the modeling makes clear that Southern and Duke's IRPs are off track from what's needed to achieve these goals.

Combined, Duke Energy and Southern Company make up approximately 45 percent of total Southeast retail sales. In fact, a competitive market with no carbon policy does a better job of reducing emissions than Duke and Southern's efforts.

This reveals two dynamics: First, vertically integrated utilities' incentives to maintain and earn on existing infrastructure conflicts with both customer well-being and environmental goals. Second, regional transmission and operational approaches are more effective at integrating high shares of renewable electricity, and Duke and Southern hamper their own efforts to decarbonize at least cost by resisting regionalization efforts.

in the RTO Scenario, largely due to the retirement of all remaining coal. In the IRP Scenario, those emissions remain virtually flat. [xvii]

The emissions reductions of both carbon dioxide and other major air pollutants is significant in the RTO Scenario. The RTO with Nuclear Scenario modeled illuminates the opportunity for even greater emissions reductions with minimal cost impact, as detailed in the Technical Report, Section 2.11.



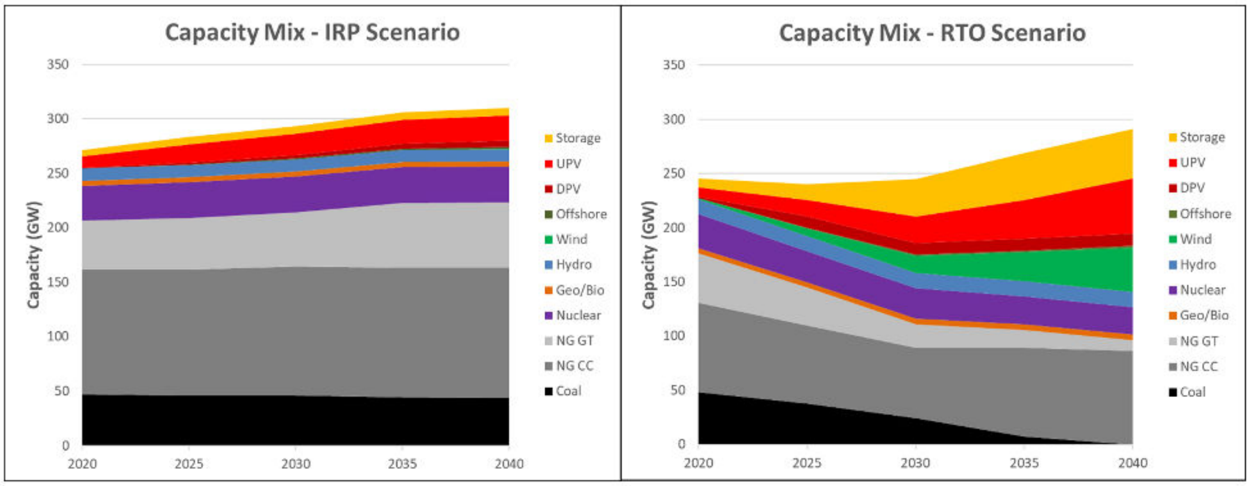
Total CO_2 Emissions from the Southeast Electric Sector in the IRP Scenario and RTO Scenarios, 2018-2040

CHANGES TO THE ELECTRICITY SYSTEM

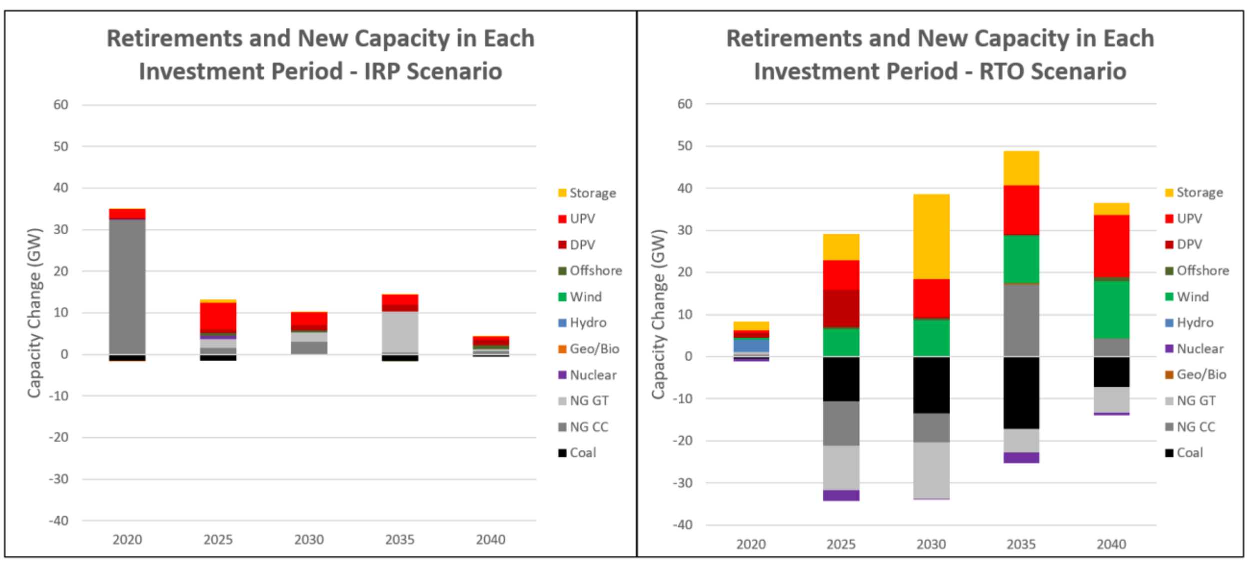
The IRP Scenario represents a particularly inefficient strategy for power systems planning. In this scenario, each utility service territory is planning to meet its peak load, plus a specified reserve margin, independently. Segmented approaches to resource planning combine with monopoly incentives to maintain existing uneconomic generation, self-build new generation, and overbuild capacity, resulting in cumulative costs exceeding those of the RTO Scenario by $384 billion by 2040.

Changing Resource Mix

Three trends become apparent by examining how the resource mix changes over time in each case. First, while the utility IRPs retain most of the existing coal fleet while adding additional fossil capacity, the RTO Scenario retires coal as it cannot compete with newer resources. Second, the IRP Scenario adds very little renewable generation, while the RTO Scenario adds significant amounts of both wind and solar PV, including significant distributed PV. Finally, the IRP Scenario relies very little on battery storage, while the RTO Scenario builds significant utility-scale and distributed battery storage as part of the cost-optimal resource mix, which also allows most of the gas peaker units to retire by 2040 as well. From this analysis it becomes clear that continuing to operate coal-fired generation and gas peakers at the expense of new clean energy resources in the region is costing customers billions.



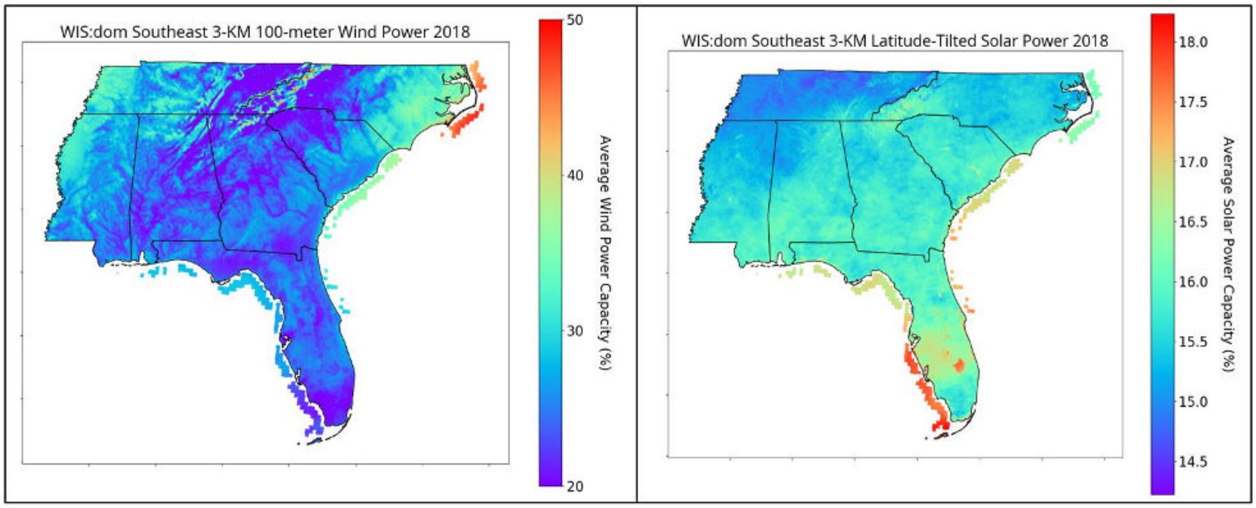
Capacity Mixes for the RTO and IRP Scenarios, 2020-2040



Cumulative Capacity Additions and Retirements in the Restructured Scenario, 2020-2040

Changes to the generation mix tell a similar story. By 2040, the majority of generation in the IRP Scenario consists of fossil fuels, whereas the majority of generation in the RTO Scenario is carbon-free. In the RTO Scenario, storage and gas combine to provide sufficient flexibility to integrate significant shares of variable renewable energy by 2040. In the IRP Scenario, there is almost no wind generation, and solar PV provides just 4 percent of annual generation. In contrast, wind and solar provide 22 percent of generation in the RTO Scenario; when aggregated with nuclear (20 percent), geothermal/bioenergy (5 percent) and hydropower (4 percent), 51 percent of the Southeast fleet is zero-carbon by 2040 in the RTO Scenario.

Defying the traditional notion that wind power is not a viable generating resource for the Southeast, the model builds a substantial amount of onshore wind throughout the region, owing to both the rapidly declining cost and increasing hub heights and rotor diameters of new wind turbines.



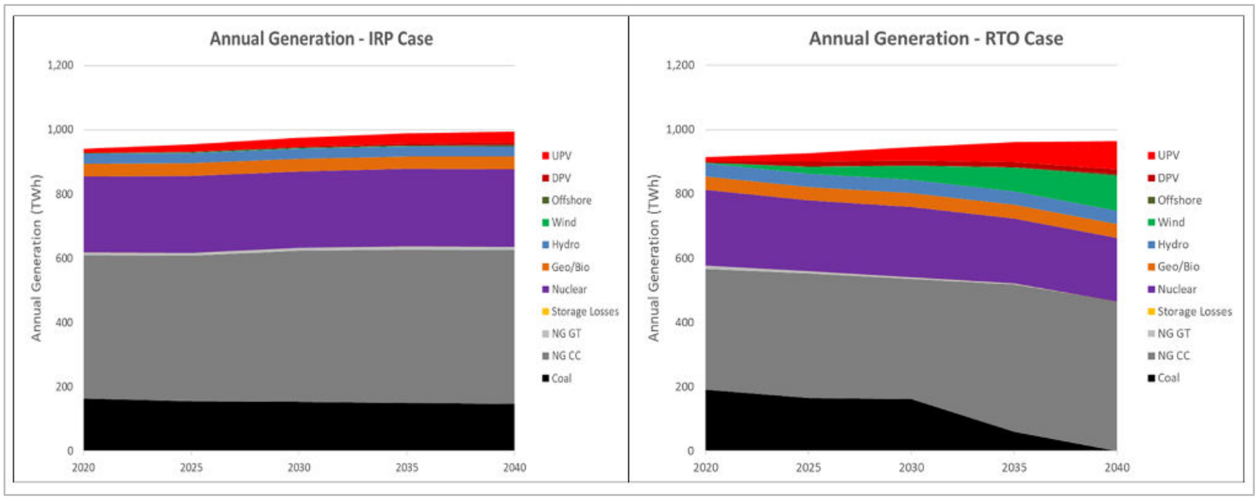
The 3-km 100-meter wind capacity resource (left) and 3-km latitude-tilted solar capacity resource (right) across the Southeast U.S. in 2018.

Additionally, wind generation in the region is particularly well-correlated with the winter peak demand, while it is anti-correlated with solar output.[xviii] Optimizing over the whole region also allows the model to take advantage of the diversity benefits of wind when it comes to meeting reliability goals.

The IRP Scenario, which relies on the capacity builds specified in each utility's respective IRP, only builds 250 megawatts (MW) of onshore wind, plus 2 GW of offshore wind hard coded in both scenarios. The RTO Scenario builds 41 GW of onshore wind, by contrast.[xix]

The availability of low-cost battery storage enables higher levels of renewable energy deployment and improves resource sharing optimization across the region in the RTO Scenario. The 46 GW of storage (a quarter of the 166 GW peak load in 2040) in the RTO Scenario provides significant load balancing and peak demand reduction, compared to just 7 GW of storage in the IRP Scenario.

This storage reduces total resource costs on the system as it not only balances variable renewables but better integrates distributed generation, adapts to inflexible nuclear generation, and reduces the need for new transmission. [xx]



Annual Generation - IRP Scenario and RTO Scenario 2018-2040

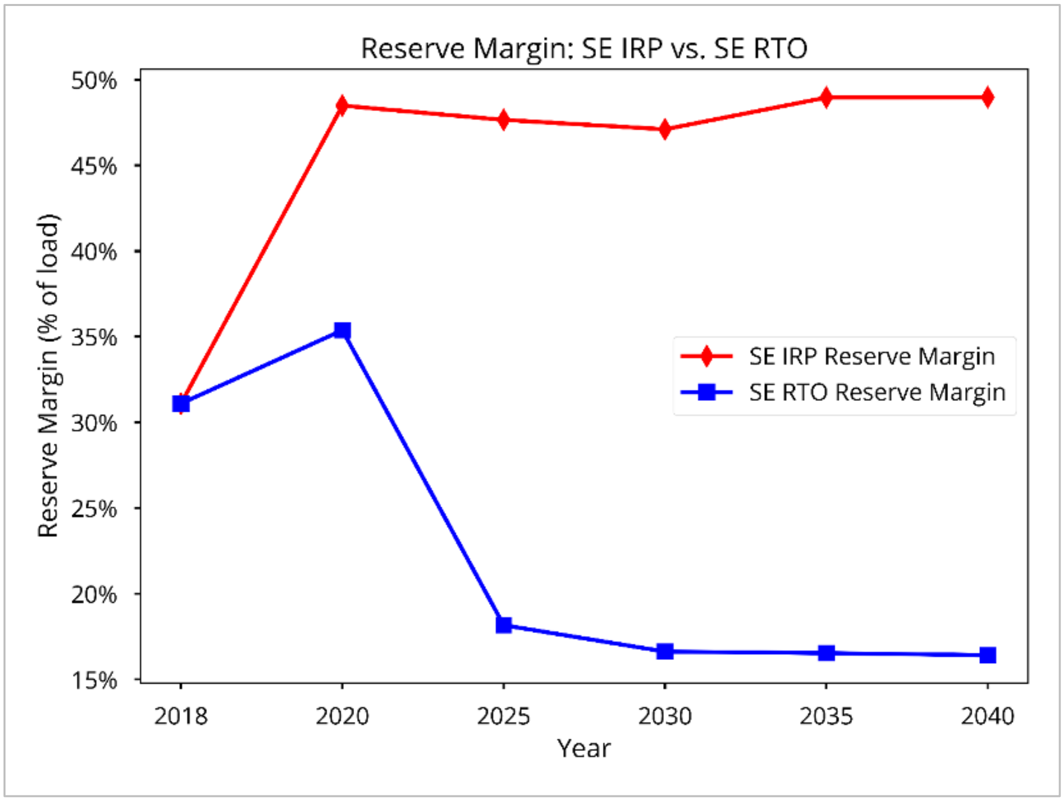
Reserve Margins

Owing to the inefficient and conservative planning regimes across utilities, the IRP Scenario results in significant overbuild. The combined planning reserve margin (PRM) of the region reaches 48 percent in 2040, which means that combined, utilities are procuring generation to meet a coincident peak demand for the region plus an additional 48 percent of reserve capacity.

This can be compared to the reference standard PRM[xxi] of 15 percent from the North American Electric Reliability Corporation, which promulgates and enforces reliability standards on the U.S. grid. It is important to note that many RTOs regularly exceed their Reference PRM targets, but few reach the level of over-procurement found in the Southeast region.[xxii]

In contrast, the RTO Scenario meets a 16 percent PRM in 2040. This contrast in reserve levels suggest the RTO system has less underutilized, and thus less wasted, capacity. Utility IRPs in aggregate are redundant and excessive on their own, but when taking a regional view where significant efficiencies could be obtained by sharing reserves, the waste becomes more apparent.

Utilities are rushing to build new gas generation that increases their earnings while planning to hold onto uneconomic coal generation for decades longer than economics would dictate. But without competition, captive customers of the monopoly utilities hold all of this risk.[xxiii]

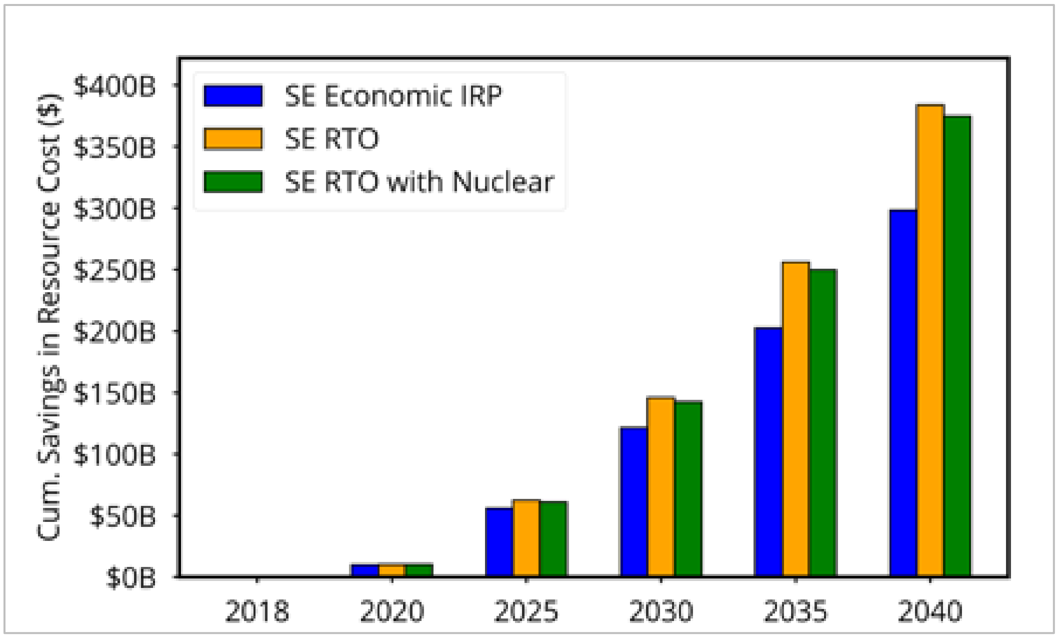


Planning Reserve Margins of the IRP and RTO Scenarios, 2018-2040

INSIGHTS FROM TWO SENSITIVITIES

We examine two modifications to the core scenarios in order to gain insight into key economic and environmental drivers in Southeast electricity market reform. In the **RTO with Nuclear Scenario**, we assume the same structure as the RTO Scenario, adding the requirement that all existing nuclear is granted license extensions through 2040 and remains online, regardless of cost-competitiveness. This scenario examines the cost and emissions tradeoffs associated with keeping existing uneconomic nuclear plants online, similar to programs recently adopted in Illinois, New Jersey, and New York.[xxiv]

In the **Economic IRP Scenario**, we allow the model to choose the appropriate cost-effective capacity mix in each sub-regional planning footprint (maintaining existing balancing area authorities), however, the model is not co-optimizing the generation, transmission, and distribution systems as it does in the RTO Scenario. This recognizes the reality that full regionalization may be politically infeasible in the near to medium term, but shows that a majority of the cost savings can still be achieved by subjecting utility procurement plans and existing generators to market competition. While more economic than the IRP Scenario, the Economic IRP Scenario still leaves significant consumer cost-savings on the table.



Cumulative Savings in Total Resource Cost of Scenarios Compared to the IRP Scenario, 2018-2040

RTO with Nuclear Scenario

Maintaining the existing nuclear fleet provides significant emissions benefits while minimally raising costs relative to the RTO Scenario. The RTO with Nuclear Scenario results in approximately $375 billion in cumulative cost savings by 2040, as compared to the $384 billion in savings under the RTO Scenario. This cost is a relatively small tradeoff for significant emissions benefits: The RTO with Nuclear Scenario leads to a 41 percent drop below 2018 levels by 2040, compared to a 37 percent drop in the RTO Scenario. Similarly, maintaining the existing nuclear fleet leads to an approximately 5 percent reduction in both NO_X and methane compared to the RTO Scenario. Maintaining the existing nuclear fleet, despite a minor 0.5 percent increase in overall system costs, leads to significant emissions and pollutant reductions.

The primary driver of these emissions reductions is the impact that additional nuclear capacity has on gas generation. The additional nuclear capacity, coupled with the flexibility that the RTO provides (to accommodate increased levels of wind and solar, extra transmission, and higher levels of storage), allows for decreased gas generation. In the RTO with Nuclear Scenario, gas capacity is approximately 5 GW lower, largely driven by the additional 7 GW of nuclear capacity that remains online.[xxv]

Economic IRP Scenario

In the Economic IRP Scenario, we allow the model to choose the appropriate, cost-effective capacity mix within each existing utility service territory, and optimize dispatch using the existing transmission network. However, the model is not co-optimizing the generation and transmission buildout between balancing authorities, nor is it co-optimizing the distribution and transmission as it does in the RTO Scenario. In effect, this scenario represents a partial step towards a fully competitive wholesale electricity market, in which the system is no longer beholden to the capacity mixes specified in each utilities' respective IRPs, but is not optimizing to gain the benefits of regionalization. One might expect a similar effect from utilities opening up capacity procurement to competition and enforcing economic dispatch of their power plants, but not participating in organized regional markets.[xxvi]

Modeling indicates some, but not all the savings, jobs, and emissions benefits of competition are attainable without regional integration exemplified by the RTO Scenario. By 2040, the Economic IRP Scenario creates approximately $298 billion in cumulative cost savings compared to the IRP Scenario – about three-quarters of the savings achieved in the RTO Scenario. Carbon emissions only drop 13 percent below 2018 levels by 2040, compared to a 37 percent decrease in the RTO Scenario. While the Economic IRP scenario expands zero-carbon resource capacity, a significant amount of coal and gas capacity remains online by 2040, leading to a smaller decrease in major air pollutants.

CONCLUSION

VCE®'s Southeast analysis makes it clear that greater competition and regional coordination could create massive cost savings, increase employment, reduce emissions, and improve market access for clean energy resources. Much of the opportunity is a function of the dysfunctional status quo. Aggregating utility integrated resource plans makes it clear they have huge opportunities for improvement. The competitiveness of the region, participation in the fast-growing clean energy economy, and market fairness depend upon making significant progress in this direction.

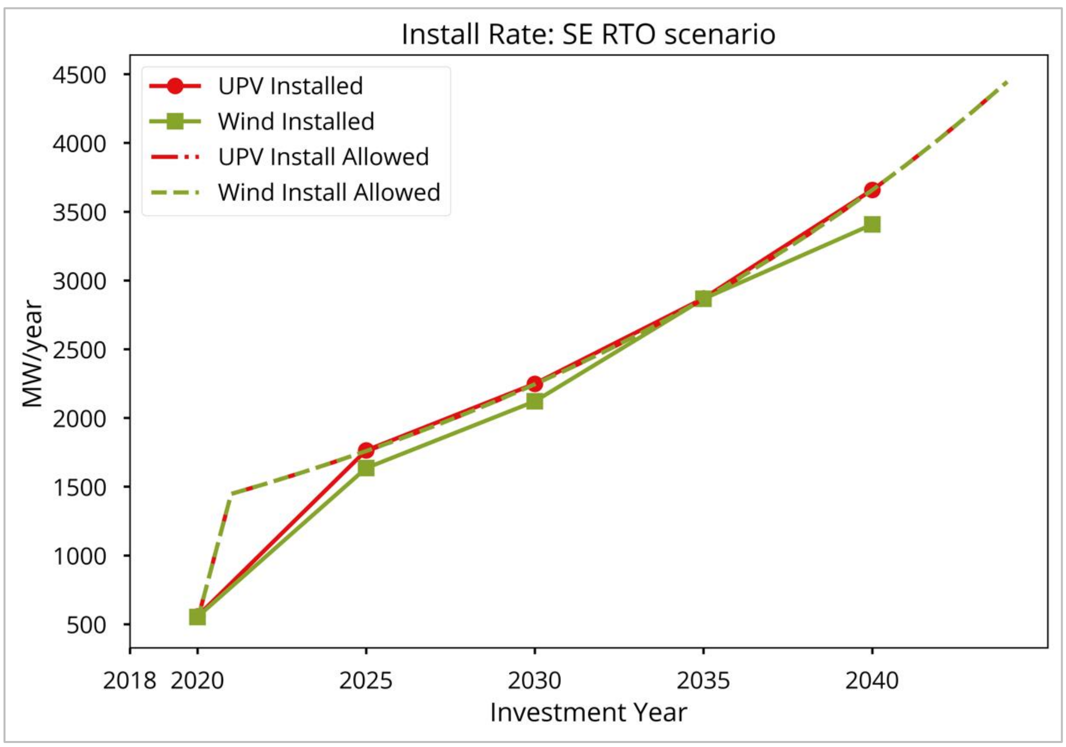
At the very least, policymakers considering going down the road to a regional market or state-level competitive procurement should be encouraged by this analysis to keep pressing in legislative and regulatory forums. It's no longer 2000 –20 years since the California Energy Crisis has proved that regional competitive electricity markets can work effectively. Incremental approaches such as an energy imbalance market, or competitive utility procurement, can yield significant benefits, and set the region on a path to continue improving the competitiveness of the electricity industry. State stakeholders where utilities block competitive reforms now have new quantitative findings to challenge the assumption that the way utilities have done business is in the public interest. We are in a period of rapid technological transition - the status quo of balkanized uncompetitive monopolies will not leverage the potential of this moment.

APPENDIX – TECHNICAL INSIGHTS

THE ROLE OF DEPLOYMENT RATES

To ensure reasonable results from capacity expansion planning, realistic constraints were imposed on the model in terms of capacity turnover and new build allowed to occur per year. The capacity turnover limits depend on several factors, such as existing supply chains that can sustain a particular buildout rate for a technology, available skilled workforce that can be called upon, disruption in host communities from retirements which leads to job losses, lost tax revenues, and other losses in the economy downstream of the power generator. In addition to the buildout limits, time lags are incorporated in installations for newer technologies.

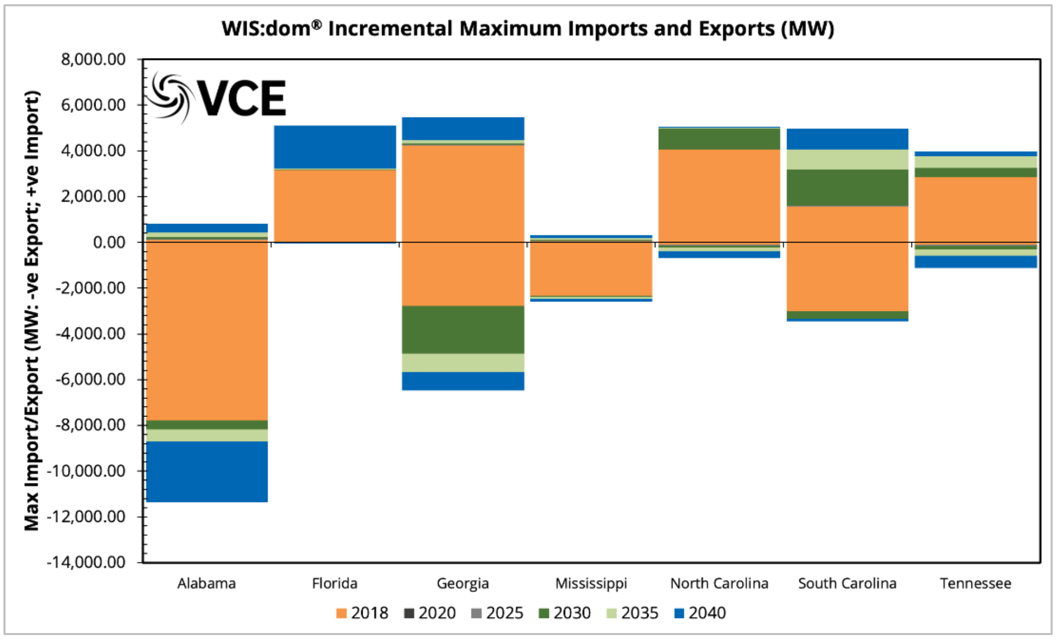
The limitation on deployment rate embedded within the WIS:dom®-P model's assumptions becomes a binding constraint on wind and solar deployment, as they are the most cost-effective resources available to the model. To reflect historical trends of patchwork policy support to overcome structural barriers, the model only allows wind and solar to grow at 1,800 MW/year annually, increasing this rate limiter by 5 percent a year in the RTO Scenario. As shown in the figure below, the RTO scenario essentially saturates these limits in all modelled years.



During model calibration, when allowed to deploy clean energy resources unconstrained, even greater total deployment of wind and solar and concomitant cost reductions were observed, along with additional transmission expansion, for further savings. Though deployment constraints must realistically exist, deployment capacity has grown faster than these limits in parts of the U.S., and much faster in parts of the world such as China. As such, the RTO Scenario represents a conservative analysis of renewable energy's possible contribution to both jobs and a future competitive electric system in the Southeast.

TRANSMISSION AND STORAGE

As clean energy deployment increases in the RTO Scenario, the transmission system plays an increasingly important role in sharing resources across the region. The import and export capacity of each state is dramatically different by 2040, as the region plans its transmission system in tandem to meet a single reserve margin. In contrast to the IRP Scenario, in which states plan their regions independently and build little to no new transmission, the RTO Scenario sees significant growth.



By 2040, the cumulative fixed costs associated with transmission are approximately $1.3 billion more in the RTO Scenario compared to the IRP Scenario. The deployment of low-cost battery storage, however, limits the need for more overall expansion of the transmission system. In effect, storage plays a similar role, serving to balance supply and demand, increase load shifting, and reduce the need for additional peaking capacity. WIS:dom®-P is able to co-optimize the deployment of storage with distribution and transmission infrastructure. Because it is modular and takes up little space, storage sited near or at renewable generation facilities limits the need to send excess power over vast distances, instead allowing local solar and wind to match local loads more effectively. This also increases the economics of lower-quality wind and solar resources, which can provide greater value paired with storage by matching load. Still, there is no replacement for some amount of transmission to access the lowest cost resources and enable efficient power system balancing across a wide geographic area. Moreover, storage and transmission serve to complement each other rather than compete.[xxvii]

ENDNOTES

[i] Technical report available at https://vibrantcleanenergy.com/wp-content/uploads/2020/08/SERTO_WISdomP_VCE-EI.pdf
[ii] All dollar values are in real 2018 dollars.
[iii] Eric Gimon et al., "The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources" (Energy Innovation & Vibrant Clean Energy, March 2019), https://energyinnovation.org/wp-content/uploads/2019/04/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL2.pdf.
[iv] Data available at https://energyinnovation.org/publication/the-coal-cost-crossover/
[v] Brian Murray, "Reforming The Carolinas' Power Markets: Producing A Panacea Or A Pandora's Box?," *Forbes*, October 11, 2019, https://www.forbes.com/sites/brianmurray1/2019/10/11/reforming-the-carolinas-power-markets-producing-a-panacea-or-a-pandoras-box/#1ba674b5c5ea.
[vi] Iulia Gheorghiu, "Duke, Southern Plan Path for Southeast Energy Imbalance Market," *Utility Dive*, July 14, 2020, utilitydive.com/news/duke-southern-plan-path-for-southeast-energy-imbalance-market/581556/.
[vii] See also Christopher Clack, "The WIS:Dom® Model: Detailed Capacity Expansion & Production Cost Modeling" (Vibrant Clean Energy, n.d.), https://www.vibrantcleanenergy.com/wp-content/uploads/2019/04/VCE-WISdom-Brochure.pdf.
[viii] Refer to Section 2.1 of the technical report for details on the IRP Scenario.
[ix] WIS:dom®-P ensures that historical capacity factors continue to account for un-economic decision making.
[x] The portion of Mississippi that is already a part of MISO is matched to EIA form 860 data.

[xi] In many RTOs, grid operators determine rates for imports and exports, known as Transmission Access Charges, which are used to recover transmission revenue requirements. The rates for importing and exporting power are determined by the grid operator and spread evenly across all consumers, providing equal access and recovery for all participants in the market. In contrast, the Southeast relies on wheeling charges, in which an independent power producer pays a fee to the utility to wheel power across its lines. Different utilities may charge different wheeling prices.

[xii] Plant Vogtle is assumed to come online in all scenarios.
[xiii] Refer to Sections 2.2 and 2.3 of the technical report.

[xiv] A job is represented by one Full-Time Equivalent (FTE) employee. The jobs analysis includes only direct jobs related to the electricity sector, and does not include indirect jobs in manufacturing, mining, fuel refining, or delivery. For a detailed explanation of the jobs analysis, please refer to Section 4.3 of the technical report.

[xv] Refer to Section 3.11 of the technical report for more details.
[xvi] Refer to Section 2.1 of the technical report for the impacts on renewable energy buildout constraints.
[xvii] Sections 2.4 and 2.11 of the technical report discuss emission reductions in the SE RTO and SE RTO with Nuclear.
[xviii] Refer to Section 4.4.4 of the technical report.
[xix] Refer to Sections 4.2 and 4.3 of the technical report.
[xx] Refer to Section 2.6 of the technical report.
[xxi] "**Planning reference margins** are reserve margin targets based on each area's load, generation capacity, and transmission characteristics. In some cases, the planning reference margin level is required by states, provinces, independent system operators, or other regulatory bodies. Reliability entities in each region aim to have their anticipated reserve margins surpass their planning reference margins." "NERC Report Highlights Potential Summer Electricity Issues for Texas and California" (Energy Information Administration, June 18, 2019), https://www.eia.gov/todayinenergy/detail.php?id=39892#.
[xxii] "2020 Summer Reliability Assessment" (North American Electric Reliability Corporation, June 2020), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2020.pdf.
[xxiii] Refer to Section 2.7 of the technical report.

[xxiv] See, e.g., Patrick McGeehan, "New York State Aiding Nuclear Plants With Millions in Subsidies," *New York Times*, August 1, 2016, sec. A.

[xxv] Refer to Section 2.4 of the technical report
[xxvi] Refer to Section 2.2 of the technical report

[xxvii] Refer to Section 2.8 of the technical report.