ACHIEVING 100% CLEAN ELECTRICITY IN THE SOUTHEAST

APPENDICES

APPENDIX I: METHOD

METHOD FOR BUILDING A RESOURCE PATHWAY

The goal for each pathway is to develop an illustrative resource mix that could meet energy and capacity needs in 2035 without emitting carbon dioxide (CO_2), and thus show the options available to the major Southeast utilities to meet a Clean Electricity Standard (CES). These pathways are not intended to be proscriptive. Our intention with this work is to show that getting to zero carbon is achievable and that there are several pathways to be taken that involve a variety of program and technological choices. The most important action is to start as soon as possible.

TARGET

- 100% clean electricity by 2030 for the Tennessee Valley Authority
- 100% clean electricity by 2035 for Southern Company, Duke Energy, and NextEra

Step 1: Start with current utility plan

First, annual data for each utility operating company was assembled from each company's latest resource plan. These plans are housed in SACE's database, SENFO, where they are used to track progress on the deployment of clean energy resources like energy efficiency and solar as well as progress on decarbonization.

Using the utility's current resource plan for the target year, the fossil plants were removed.

Step 2: Apply distributed energy resource assumptions

Next, we developed assumptions on the impact of a sustained investment in distributed energy resources (DERs), defined here at a high-level as demand-side measurement and distributed solar. These assumptions were calculated as a percent of either annual energy demand or seasonal peak demand. They represent the impact of DERs across all customer classes (residential, commercial, industrial, etc.). Starting with these resources allows us to then build up each pathway with additional technologies needed to meet the remainder of energy and peak demand after DERs have been applied.

By starting with a DER build-out that is both aggressive and achievable we were able to dial it back to look at scenarios where DER investment is lower. We assume that this DER forecast replaces any DERs identified in the utility's current resource plan.

Step 3: Apply assumptions on wind resources

Infrastructure and resource potential currently limit the Southeast utilities' ability to deploy onshore and offshore wind energy resources at scale. For instance, the amount of wind from high-wind-resource areas to the west is limited by the import capabilities of the current transmission grid. As a next step we developed three sets of assumptions related to wind.

- Transmission import capability to define the amount of onshore wind imported from states to the west.
- Offshore wind potential and the level of development for each Southeast state with offshore wind potential. We developed high, medium, and low development cases.
- Onshore wind potential and the level of development for each Southeast state. Instead of pre-defined scenarios we identified the achievable potential by state and allowed for each scenario to adjust the percent of that achievable potential that is developed by the target year.

Step 4: Meet energy needs

With the fossil resources removed and DER and wind resource assumptions applied to annual energy demand, large-scale solar was added to meet the remaining annual energy needs for each utility.

Step 5: Meet reserve margin needs

After energy needs were met, the capacity needed to meet a 15% reserve margin was calculated for both summer and winter based on the utility's forecasted peak demand for each season. The existing resources (minus fossil, plus wind and solar from steps 3 and 4) were summed for their ability to meet the reserve margin needs using a capacity credit method, where a percent of nameplate capacity is assumed to be available to meet that season's peak demand. If a gap exists it was primarily filled through additions of energy storage and utility-scale solar, with small additions from the other renewable category (defined in the next section), as appropriate.

Step 6: Check resource mix against hourly shape on peak days

Once a resource mix that meets both annual energy and reserve margin capacity was developed it was then tested to be sure that each hour in a peak day has enough supply to meet demand. To do this, an actual hourly daily load profile was pulled for each utility operating company for both a winter peak and summer peak day from historical hourly data. Then an hourly resource shape was developed based on profiles of how much of each resource could be expected to be generating (or reducing load) in each hour based on the location of the resource and the season or month. Storage is assumed to be charged during hours when excess generation occurs and was used to smooth the load only to the degree it could be charged within the same 24-hour period in which it discharged.

If excess generation occurred in any given hour, even after accounting for energy storage charging, that generation was curtailed in the following order: other renewable, hydro, western wind, offshore wind, and local wind and local utility-scale solar. We chose to curtail the “other renewable” category first because it has the potential for the most local pollutions, particularly near frontline communities, from resources like biomass. A full list of what is included as “other renewable” is in the next section. This curtailment in the CES pathways, which appears likely to occur on most days, would reduce the amount of local pollution associated with these resources.

APPENDIX II: ASSUMPTIONS

DEMAND FORECASTS

Utility forecasts for annual energy needs, summer peak demand, and winter peak demand were derived from the 2020 FERC 714 filing.[1] Peak load days for hourly analysis were also derived from FERC 714 data compiled from analysis of 20 years of hourly demand in each utility. The average spring day was calculated as an average for each hour in March (for Florida utilities) or April (for the rest of the utilities) for the years 2014-2016.

DEMAND-SIDE MANAGEMENT

Energy Efficiency

Energy efficiency, as we use the term in this analysis, is a combination of utility programs designed to help customers reduce or shift load. We use this term broadly in this report. We consider both traditional and innovative programs will be key to this strategy. Traditional programs include replacement of inefficient furnaces and air conditioners with more efficient appliances, and weatherization of homes and buildings so that less energy is needed to keep them cool in the summer and warm in the winter. Innovations in this space include rate designs that drive customers to reduce or shift usage away from certain times of the day or week. Assumptions on the energy provided by energy efficiency are built up from current (2019) energy efficiency levels and based on a percentage of annual energy. The capacity provided is based on the amount of energy reduced during the peak hour.

Our energy efficiency savings projections utilize an escalating level of incremental annual efficiency savings target for each year as a percentage of utility retail sales, which counts only first year savings for measures implemented in a given year. The incremental annual savings target is based on a 10-year ramp up, whereby each utility reaches 3.18% of retail sales by 2032.[2] Each utility is assumed to begin in 2023 with annual savings

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[1] FERC 714 data can be found here: ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data.

[2] For reference, two utilities in Massachusetts achieved over 3% of savings as a percent of sales. For more see the American Council for an Energy Efficiency Economy's *2020 Utility Energy Efficiency Scorecard*, which can be found here: aceee.org/utility-scorecard.

levels equal to what they reported to their respective regulatory commissions in 2019, which can be found in Appendix B of SACE's Energy Efficiency in the Southeast Report. [3]

The amount of annual increase for each utility depends on their respective 2023 starting points, ranging from 0.24% for DEC, to 0.35% for TVA, FPL, Gulf Power, and Alabama Power. Each year, the utility's annual savings level increases steadily by its corresponding increment until all utilities reach 3.18% incremental annual savings in 2032.

To account for persistent savings from efficiency measures implemented in previous years we assume a 7-year average measure life. This means that each year's incremental annual savings are added to the persistent savings from the preceding six years to determine each year's total annual savings (incremental savings in a given year, plus persistent savings).

Capacity savings associated with these energy efficiency savings levels were generated using the Electric Power Research Institute's End Use Load Shapes tool.[4] Measure mix figures were roughly based on DEC's percentage load by end use from pages 23-26 of the Market Potential Study (MPS) it submitted with its 2020 IRP.[5]

Demand Response

Demand response resources provide additional capacity to meet reserve margin requirements for each utility but are assumed to shift demand to other hours or days, or at least not reduce energy needs in the long-term. Thus, they are assumed to have capacity but do not count toward reducing the annual energy needs. During the peak day analysis demand response was assumed to reduce the hourly load for at least two hours and up to 24 hours when evaluating each pathway against hourly demand during peak days.

Our projections for Winter peak reduction from demand response programs and rate design changes were based on analysis conducted by Duke Energy Carolinas (DEC), by combining:

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[3] SACE's Energy Efficiency in the Southeast Report can be found here: cleanenergy.org/wp-content/uploads/22Energy-Efficiency-in-the-Southeast22-third-annual-report-2021.pdf, hyperlink to Appendix B on page 28.

[4] Electric Power Research Institute's End Use Load Shapes tool can be found here: loadshape.epri.com/enduse.

[5] The MPS can be found here: dms.psc.sc.gov/Attachments/Matter/5dd1b614-dd18-48ca-a7e9-f16b0809e273.

- Winter peak demand response potential from Duke's 2020 EE/DSM MPS, adjusted upward so that all customers are included (i.e. commercial and industrial customers that are presently opted out).
- The additional savings levels from demand response and rate designs for winter peak savings in Duke's Winter Peaking Study (also adjusted for inclusion of presently opted out commercial and industrial customers).[6]

Combined, this came to 7.5% of DEC's winter peak load in 2030 and 7.7% in 2035. The same percentage was applied to each utility's respective winter peak forecast.

Our projections for Summer peak reduction from Demand Response and Rate Design followed a similar approach - using DEC's existing summer DR programs (which were adjusted for full participation by presently opted out commercial and industrial customers and carried forward through the analysis period) and the same DEC savings levels attributed to rate designs for winter peak savings in Duke's Winter Peaking Study (also adjusted for full participation by presently opted out commercial and industrial customers). Combined, this equates to 12.8% of summer peak load in 2030 and 13% in 2035, which was applied to each utility's respective summer peak forecast.

The energy efficiency and demand side management methodology described above, and the associated energy and capacity savings levels, are meant to be illustrative of how these resources can contribute to a clean energy resource portfolio and are not intended to be construed as reflecting the maximum potential for energy efficiency for utility efficiency portfolios in the region.

SOLAR

The analysis generalizes solar into two types. While there are a wide range of sizes and applications for solar, we have considered solar to either be distributed or large-scale in this analysis. All solar is assumed to be built within the utility's service territory.

Distributed Solar

Distributed solar can mean traditional rooftop solar that is behind-the-meter for residential and small commercial customers, but it can also mean other kinds of small solar projects that are distributed throughout the grid.[7] The main assumption is that they

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[6] The WPS can be found here: cleanenergy.org/news-and-resources/duke-winter-peaking-study/.

[7] For more on the economic and grid benefits of distributed solar, see Vibrant Clean Energy's report *Why Local Solar for All Costs Less: A New Roadmap for the Lowest Cost Grid*, which can be found here: https://www.vibrantcleanenergy.com/wp-content/uploads/2020/12/LocalSolarRoadmap_FINAL.pdf

are connected to the distribution system, not the transmission system, and that they are fixed tilt instead of tracking. While we did not specify a project size, these are generally assumed to be small projects.[8] The assumption on penetration of distributed solar is based on a percent of load that is tailored to the states included in each utility's service territory.

For assumptions on the amount of distributed solar we started with the technical potential for distributed solar from the National Renewable Energy Laboratory (NREL).[9] The DER-focused pathway assumes 30% of the technical potential of distributed solar is achieved by 2035 for most states, except for Florida and Tennessee that are assumed to achieve 35% by 2035. To calculate the nameplate capacity, a 16% capacity factor was assumed.

Large-Scale Solar

The amount of large-scale solar was added to each pathway portfolio to meet the required energy needs (after DERs and wind), reserve margin needs, and to charge energy storage to meet daily needs during each sample peak day. All large-scale solar was assumed to be built within the utility's service territory. To calculate the nameplate capacity, a 25% capacity factor was assumed.[10]

Capacity Value and Hourly Profile

For the capacity value and the hourly generation for distributed solar we used actual solar resource data at several locations within each utility service territory and hourly historical data. For distributed solar, a fixed tilt solar array was assumed. For large-scale solar, a tracking solar array was assumed.

WIND RESOURCES

There are three types of wind resources considered in this analysis: in-region onshore wind, western onshore wind, and offshore wind. In-region onshore wind is assumed to be built within the utility's service territory. High hub heights and long blade lengths for wind turbines allow the development of wind energy in regions with lower wind

[8] The NREL potential study used here evaluates projects for small, medium, and large buildings. Projects are assumed to be as small as 1.5 kW, and the average large building is assumed to have roof space for approximately 668 kW.
[9] NREL's Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment can be found here: nrel.gov/docs/fy16osti/65298.pdf.
[10] Capacity factor based on actual data and projections from NREL's Annual Technology Baseline (ATB), which can be found here: atb.nrel.gov/.

resources. Offshore wind is assumed to be built and connected directly to the utility's service territory. Western wind is assumed to be built in states in the Midwest with high wind resources, and transmission connecting the Midwest to the Southeast is assumed to be expanded. The wind capacity factors and hourly generation profiles are based on simulated wind turbines and data within the utility's service territory or a combination of Midwest states.

Onshore Wind

The technical potential for in-region wind by state was pulled from NREL's SLOPE tool and a percent of that potential was assumed to be developed, then the percent of load each utility serves in each state was used to convert state potential to potential within the utility's service territory.[11] This level of onshore wind was used for the DER-focused CES pathway, For the LSR-focused CES pathway the percent of technical potential achieved was increased by 1 percentage point (so Alabama achieved 1.0% of technical potential in 2035 in the DER-focused CES pathway and 2.0% of technical potential in 2035 in the LSR-focused CES pathway).

TABLE 1. PERCENT OF TECHNICAL ONSHORE WIND POTENTIAL ACHIEVED IN 2030 AND 2035 BY STATE

	% ASSUMED ACHIEVED IN 2030	% ASSUMED ACHIEVED IN 2030
ALABAMA	0.8%	1.0%
FLORIDA	-	-
GEORGIA	1.5%	3.8%
KENTUCKY	-	-
MISSISSIPPI	1.8%	2.7%
NORTH CAROLINA	1.5%	4.0%
SOUTH CAROLINA	1.5%	4.0%
TENNESSEE	2.5%	3.0%

The onshore wind speed category estimated from NREL wind speed data by state and converted to annual capacity factors based on NREL's 2020 Annual Technology Baseline (ATB).[12]

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[11] NREL's SLOPE tool can be found here: gds.nrel.gov/slope.
[12] NREL's 2020 ATB can be found here: https://atb.nrel.gov/.

Hourly profiles for onshore wind, both in-region and western wind were derived by averaging the hourly results from NREL's SAM model for a 100 MW wind farm with 120m tall at 8 locations.[13] Then the monthly hourly profile that matched the month in which the utility peak day occurred was used to match generation to hourly demand during that peak day.

Offshore Wind

For offshore wind assumptions, we started with the technical potential by state from NREL's SLOPE tool. The viable generation was estimated to be approximately 25% of technical potential. For each scenario a percent of the total viable potential achieved was set by state. These estimates were applied to each utility based on its coverage within each state.

TABLE 2. PERCENT OF VIABLE OFFSHORE WIND POTENTIAL ASSUMED TO BE DEVELOPED BY 2035 BY SCENARIO

	MEDIUM DEVELOPMENT SCENARIO	HIGH DEVELOPMENT SCENARIO
ALABAMA	5%	10%
FLORIDA	10%	25%
GEORGIA	3%	5%
MISSISSIPPI	5%	10%
NORTH CAROLINA	15%	20%
SOUTH CAROLINA	15%	20%

Hourly profiles for offshore wind were derived from NREL's SAM model using an average of up to 8 locations and averaging hourly generation at each location for each month of the year. Then the monthly hourly profile that matched the month in which the utility peak day occurred was used to match generation to hourly demand during that peak day.

TRANSMISSION

Because we are not modeling power flows, the impact of transmission is mainly seen in this analysis through the ability to rely on wind from states to the west of the utilities in question. Therefore, we decided to rely on transmission build-out results from another

[13] NREL's SAM can be found here: https://sam.nrel.gov/.

study and adapt them to our needs. We started with the increased transmission import capability in the High Carbon, High Wind case in the Vibrant Clean Energy report, released October 2020, "Consumer, Employment, and Environmental Benefits of Electricity Expansion in the Eastern U.S."[14] From that we developed assumptions on the amount of western wind that would stay within each state in the years 2030, 2035, and 2040.

In addition, we assumed the Southern Cross transmission project begins operation in 2030 and provides 1 MW of additional western wind capacity each for Alabama and Georgia and 2 GW additional western wind capacity for Mississippi.

TABLE 3. CAPACITY (MW) OF WESTERN WIND THAT SINKS IN EACH STATE

	2030	2035	2040	2040
ALABAMA	1,230	5,575	5,575	5,985
FLORIDA	4,102	4,102	4,238	4,238
GEORGIA	1,015	3,037	11,491	12,762
KENTUCKY	4,037	7,004	7,004	7,004
MISSISSIPPI	4,070	5,374	4,874	4,874
NORTH CAROLINA	1,144	1,360	1,360	1,360
SOUTH CAROLINA	1,433	1,766	1,766	1,766
TENNESSEE	2,109	2,109	6,358	6,358

OTHER RENEWABLE, HYDRO, NUCLEAR

For purposes of this analysis, any resource in current utility resource plans that is expected to be operating in 2030 (for TVA) or 2035 (for the rest of the utilities) and emits no net CO_2 is assumed to remain online. That includes nuclear, hydroelectric, landfill gas, and biomass.[15] We acknowledge these biomass plants generate local pollution that harms frontline communities, and that many may be net CO_2-positive. We also note that these resources are a small part of the overall portfolios (<1%), meaning they can be replaced with new renewable technologies to mitigate the local issues and

[14] Vibrant Clean Energy report, "Consumer, Employment, and Environmental Benefits of Electricity Expansion in the Eastern U.S." can be found here: https://www.vibrantcleanenergy.com/wp-content/uploads/2020/10/EIC-Transmission-Decarb.pdf.
[15] Many existing and proposed CES policies do not include biomass.

potential CO_2. Because these are lumped into the generic "other renewable" category in the final clean electricity pathways, replacing problematic biomass plants with new clean resources will not change the analysis.

Several nuclear units have operating licenses that are set to expire before 2035, and while for most cases we assume those operating licenses are extended, we did explore some scenarios where the licenses are not extended and power demand must be met without those units.

No new nuclear or hydroelectric resources are assumed in this analysis. The currently under construction Vogtle units are assumed to be online and operating in 2035. There is a small amount of new "other" clean electric generation. It was not specified what kind of other renewable this would be and could be any of the above technologies if it is shown to be truly net zero from a CO_2 emission perspective and does not harm communities or biodiversity with other kinds of pollution. It could also be any number of new, innovative renewable technologies such as hydrokinetic, or it could be an expansion of existing such as increasing the capacity at existing hydro dams. For purposes of this analysis, all resources in the "other renewable" category were assumed to have an annual capacity factor and capacity credit of 80%.

Existing hydro resources remain constant between the current utility plan and the CES pathways. Hydro resources were assumed to have a generic annual capacity factor and capacity credit of 80%. Pumped hydro storage was treated as energy storage (see below) and not like traditional hydro generation.

Nuclear resources remain constant between the current utility plan and the CES pathways except where we tested the impact of retiring nuclear units at the end of their current license. Nuclear units have high-capacity factors based on the need for generation in that future year and historical use of each unit. The capacity credit for existing nuclear was assumed to be 100%.

ENERGY STORAGE

In each utility system storage is built above what is needed to meet energy needs on peak days in order to meet reserve margin targets. As previous SACE analysis has shown, these utilities do not all peak at the same time, so a mechanism that would allow them to share resources to meet these reserve margin targets would lower the cost to serve customers.[16] This is true with or without a CES. Under this CES pathway, utilities would build storage along with solar and wind to charge the storage. Currently, in the absence of a CES, utilities across the Southeast have each proposed significant new gas capacity, primarily through new gas power plants but also by expanding the capacity at existing gas plants. With the ability to share resources, as is done in areas with electricity markets, the region as a whole would need to meet certain reserve margin criteria taking into account potential transmission constraints on the system. In the Southeast, without a regional electricity market, each individual utility builds to its own reserve margin, effectively assuming that it will operate as an island during emergencies. This is not how the grid is operated. These CES pathways provide another indication that increasing the transmission connections between utilities and between regions would provide numerous benefits by both accelerating the clean energy transition and saving customers money.

One key type of energy storage already exists in a number of Southeast utilities: pumped hydro. This type of resource can be used like either long-term storage or short-term storage. Utilities with existing pumped hydro resources include Georgia Power, Duke Energy Carolinas, and TVA. For purposes of these analyses, pumped hydro was included with battery storage and assumed to be "charged up" during the 24 hours in which it is discharged. This is an over simplification that does not capture all the benefits of pumped hydro storage, and this is an area for further study. It is likely that better treatment of existing (and potentially new/expanded) pumped hydro would reduce the need for new storage to meet these CES targets.

As explored through an alternate pathway, if the CES policy were to allow, a utility could also make a few existing gas peaking plants available as "just in case" capacity to be used during emergencies as it builds out its energy storage capacity and adapts its operations to the use of energy storage technologies on a wider scale. These peaking plants can also be adapted to run on hydrogen generates using excess renewable generation, and simultaneously put that excess generation to use while providing long-term dispatchable storage.

Energy storage was added to meet reserve margin needs and to meet hourly energy needs for sample peak days after DERs (including demand response), wind, solar, nuclear, and other generation hourly generation shapes were applied to the hourly load shape. The amount of energy storage needed was mostly driven by the reserve margin

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[16] See SACE's Seasonal Electric Demand in the Southeast report, which can be found here: https://cleanenergy.org/wp-content/uploads/Seasonal-Electric-Demand-in-SE-SACE-Final.pdf.

requirements, meaning it was not all used during each peak day, but is there for emergencies and to fill in in case of outages.

The energy storage is assumed to be a generic resource and includes existing pumped hydro and planned battery capacity. While the amount of energy storage added in these pathways could be seen as all utility-scale battery storage, we like to think there is a lot of room for additional energy storage applications that can provide multiple benefits beyond meeting reserve margin requirements and balancing load. One example is electric fleets such as school buses that will be needed at known times but can also provide additional storage to meet load in the evenings, during the summer, and can charge during the day when solar generation is highest.

Since we assumed that all storage needed for a peak day would be charged within that same 24 hours, we did not assume any of the storage added is long-term storage. This is an area where technological innovation and bringing technologies to market can lower the total amount of new resources needed in any of these pathways.

EXCESS GENERATION

Generating electricity from solar and wind is different from generating electricity using a combustion process, as has been done with fossil and nuclear fuels for the last hundred years. A shift to generating most of our electricity with solar and wind is doable but will change the way the grid is planned and operated. One part of this change is that to generate enough energy to meet peak days, we will have to build more renewable generating capacity and storage than we can use on many days of the year. While this is sometimes thought of as a bug in the system, again because it requires a change to how we plan and operate the system, it can also be a feature. The excess generation that is generated on these non-peak days has many potential uses. This report does not focus on those uses; several reports and papers have come out on this topic recently and we encourage you to explore and follow that research. For our purposes, a few ideas of ways to use this excess generation include the following:

- Charge long-term or seasonal storage, thus cutting down on the total amount of storage needed.
- Meet flexible load, such as industries that can ramp up production during the spring and fall, and ramp down production on peak days.
- Generate “green hydrogen” to replace direct fossil fuel use in industrial processes and other hard-to-decarbonize sectors, or as a form of long-term storage to generate electricity through a hydrogen fuel cell or combustion turbine.
- Meet load in other parts of the country.

APPENDIX III: CAPACITY BY TYPE FOR ALL PATHWAYS

Utility	Pathway	Total Installed Capacity (MW)										
		EE & DR	Distributed solar	Large-scale solar	In-region, onshore wind	Offshore wind	Western, onshore wind	Existing hydro	Other renewable	Existing nuclear	Fossil	Storage
Tennessee Valley Authority in 2030	Current utility plan	82	283	1,896	27	0	1,209	4,964	277	8,440	23,217	1,753
	DER-focused CES	6,867	5,782	23,436	6,768	0	5,562	4,964	1,077	8,440	0	9,100
	LSR-focused CES	6,288	4,930	22,836	10,454	0	5,562	4,964	517	8,440	0	8,520
Alabama Power in 2035	Current utility plan	3	10	497	460	0	0	1,730	0	1,776	9,217	0
	DER-focused CES	2,985	3,508	5,937	1,893	0	3,525	1,730	0	1,776	0	4,100
	LSR-focused CES	2,737	2,923	4,897	3,326	0	3,525	1,730	0	1,776	0	3,720
Georgia Power in 2035	Current utility plan	71	463	4,737	251	0	0	627	800	3,069	19,284	540
	DER-focused CES	6,202	6,119	8,337	3,894	557	1,839	627	1,200	3,069	0	6,340
	LSR-focused CES	5,768	5,099	9,737	4,852	929	1,839	627	800	3,069	0	6,400
	DER, no nuke extensions	6,202	6,119	11,137	3,894	0	1,839	627	1,200	2,606	0	7,000
Mississippi Power in 2035	Current utility plan	1	10	368	0	0	0	0	0	0	3,546	0
	DER-focused CES	541	642	2,468	1,093	268	1,122	0	240	0	0	1,000
	LSR-focused CES	497	535	2,268	1,498	537	1,122	0	160	0	0	840

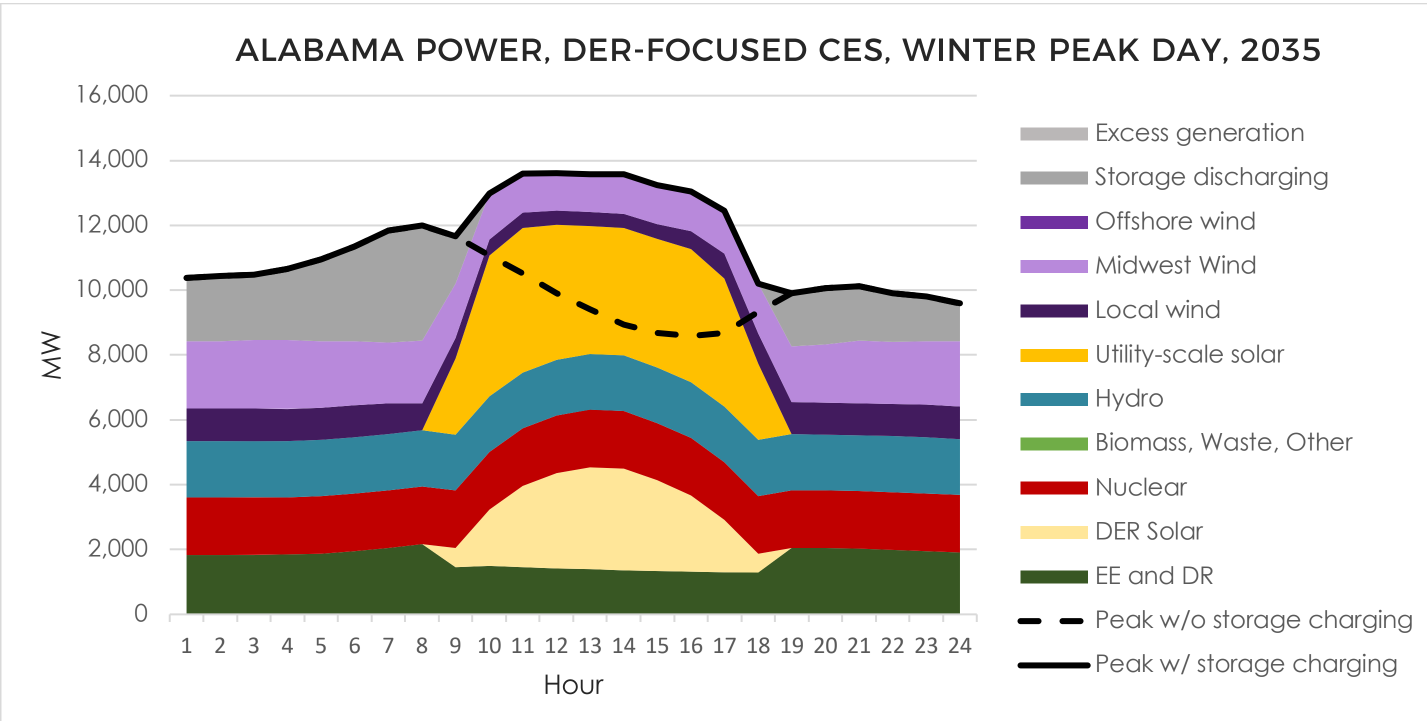
Utility	Pathway	Total Installed Capacity (MW)										
		EE & DR	Distributed solar	Large-scale solar	In-region, onshore wind	Offshore wind	Western, onshore wind	Existing hydro	Other renewable	Existing nuclear	Fossil	Storage
Duke Energy Progress in 2035	Current utility plan	67	428	5,777	62	0	0	193	3	2,613	8,555	0
	DER-focused CES	2,994	3,034	16,437	2,942	2,143	522	193	803	2,613	0	6,700
	LSR-focused CES	2,761	2,529	19,257	3,662	2,858	522	193	403	2,613	0	7,080
	DER, no nuke extensions	2,994	3,034	16,697	2,942	2,143	522	193	2,003	1,371	0	7,820
	DER, no offshore wind	2,994	3,034	18,197	2,942	0	522	193	1,203	2,613	0	6,320
Duke Energy Carolinas in 2035	Current utility plan	124	680	5,410	500	0	0	1,178	23	5,183	17,592	2,073
	DER-focused CES	6,517	5,867	18,010	3,165	4,393	1,079	1,178	983	5,183	0	5,920
	LSR-focused CES	6,039	4,889	21,990	3,831	5,858	1,079	1,178	23	5,183	0	6,860
	DER, no nuke extensions	6,517	5,867	20,530	3,165	4,393	1,079	1,178	3,023	2,698	0	8,500
	DER, no offshore wind	6,517	5,867	23,770	3,165	0	1,079	1,178	1,423	5,183	0	5,340
Duke Energy Florida in 2035	Current utility plan	18	718	2,399	0	0	0	0	47	0	10,765	0
	DER-focused CES	2,759	4,689	11,599	0	1,128	644	0	847	0	0	8,180
	LSR-focused CES	2,537	4,019	13,359	127	2,819	644	0	447	0	0	8,580
	DER, no offshore wind	2,759	4,689	12,719	0	0	644	0	1,047	0	0	7,960

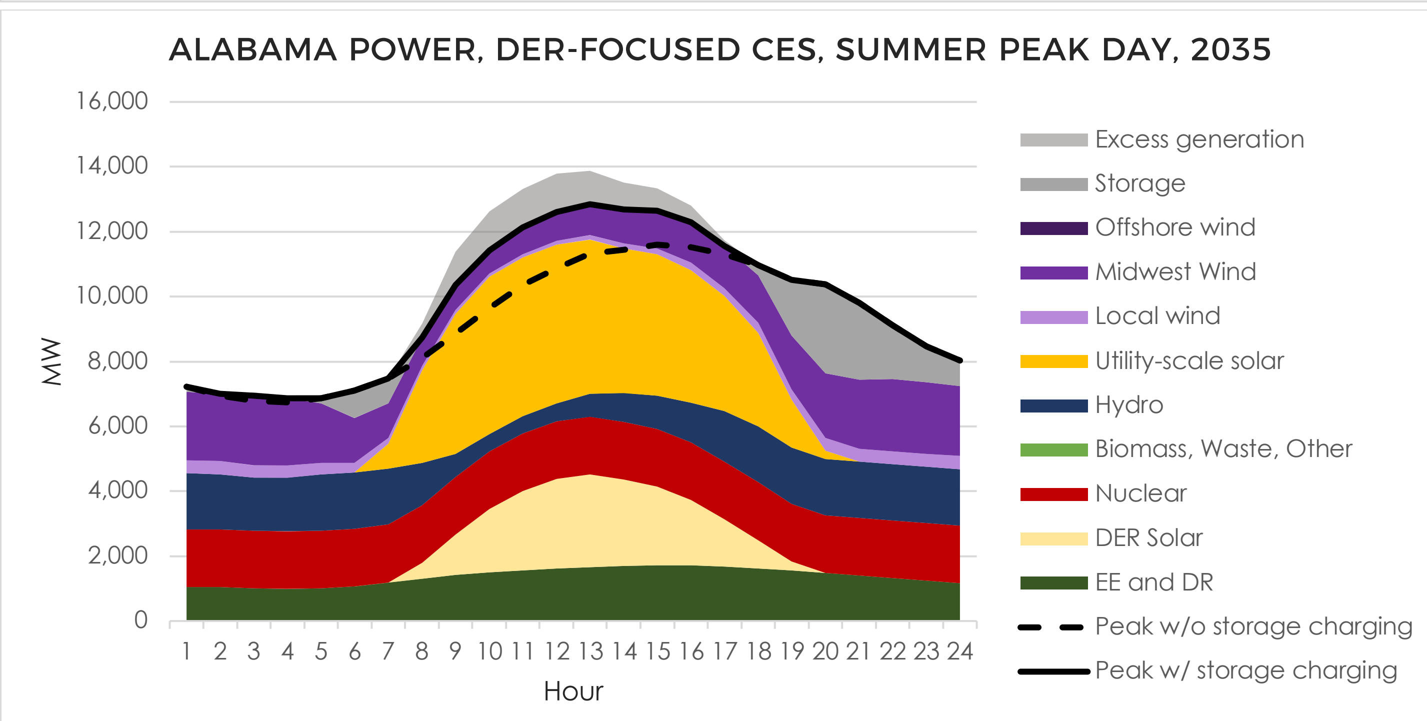
Utility	Pathway	Total Installed Capacity (MW)										
		EE & DR	Distributed solar	Large-scale solar	In-region, onshore wind	Offshore wind	Western, onshore wind	Existing hydro	Other renewable	Existing nuclear	Fossil	Storage
NextEra (FPL & Gulf) in 2035	Current utility plan	53	663	12,134	0	0	200	1	516	3,794	24,262	1,179
	DER-focused CES	9,602	13,992	19,074	0	3,512	2,207	1	1,116	3,794	0	11,280
	LSR-focused CES	8,976	11,993	19,834	396	8,781	2,207	1	1,156	3,794	0	9,640
	DER, no offshore wind	9,602	13,992	26,694	0	0	2,207	1	1,516	3,794	0	11,780

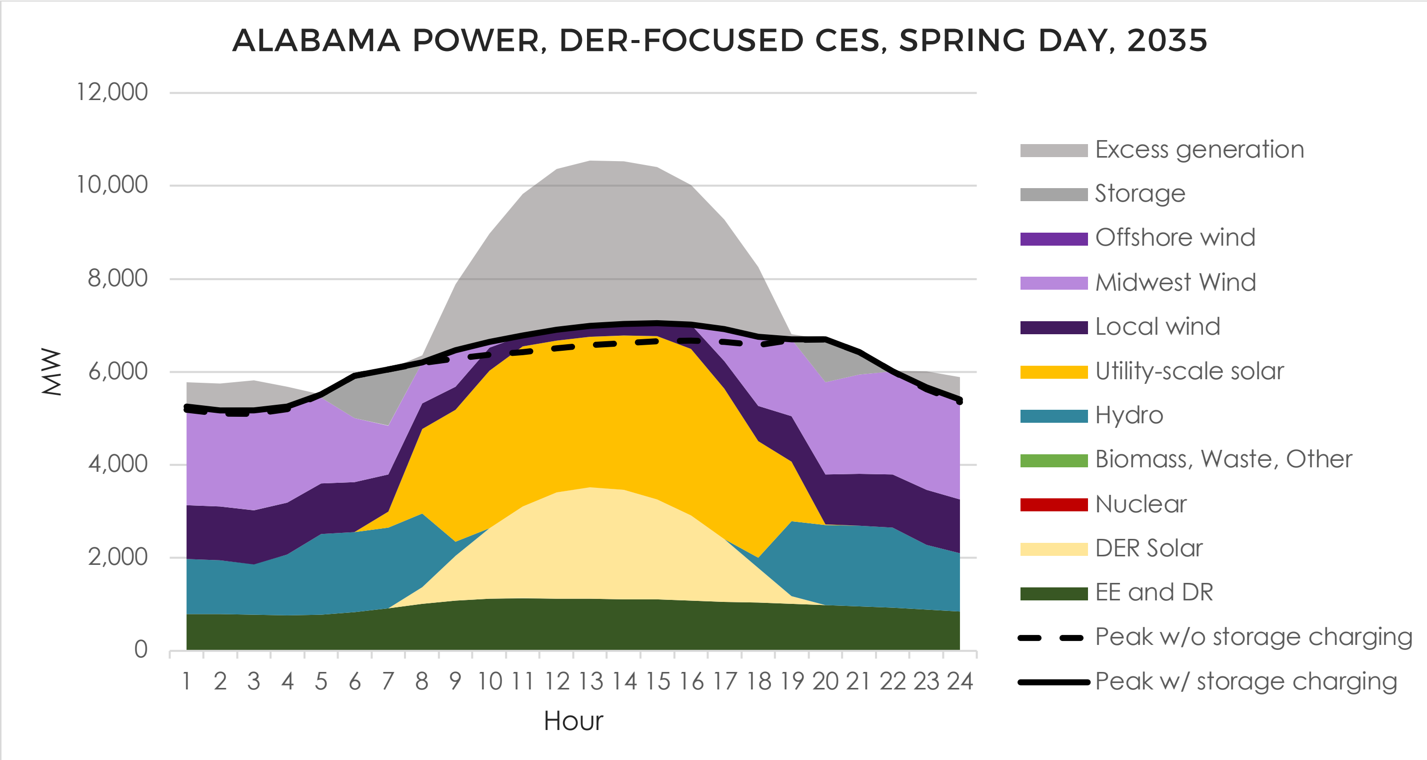
APPENDIX IV: HOURLY PROFILE CHARTS

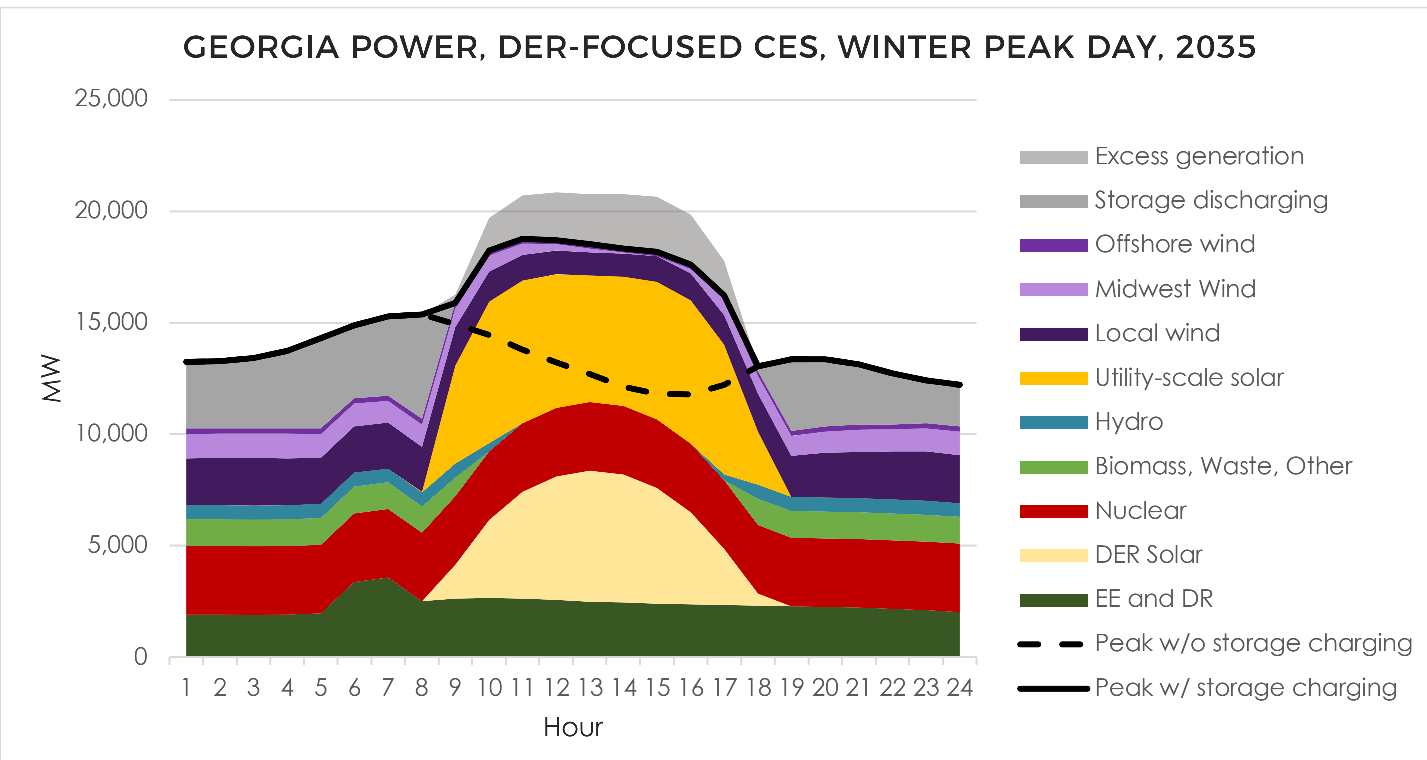
DER-FOCUSED CES

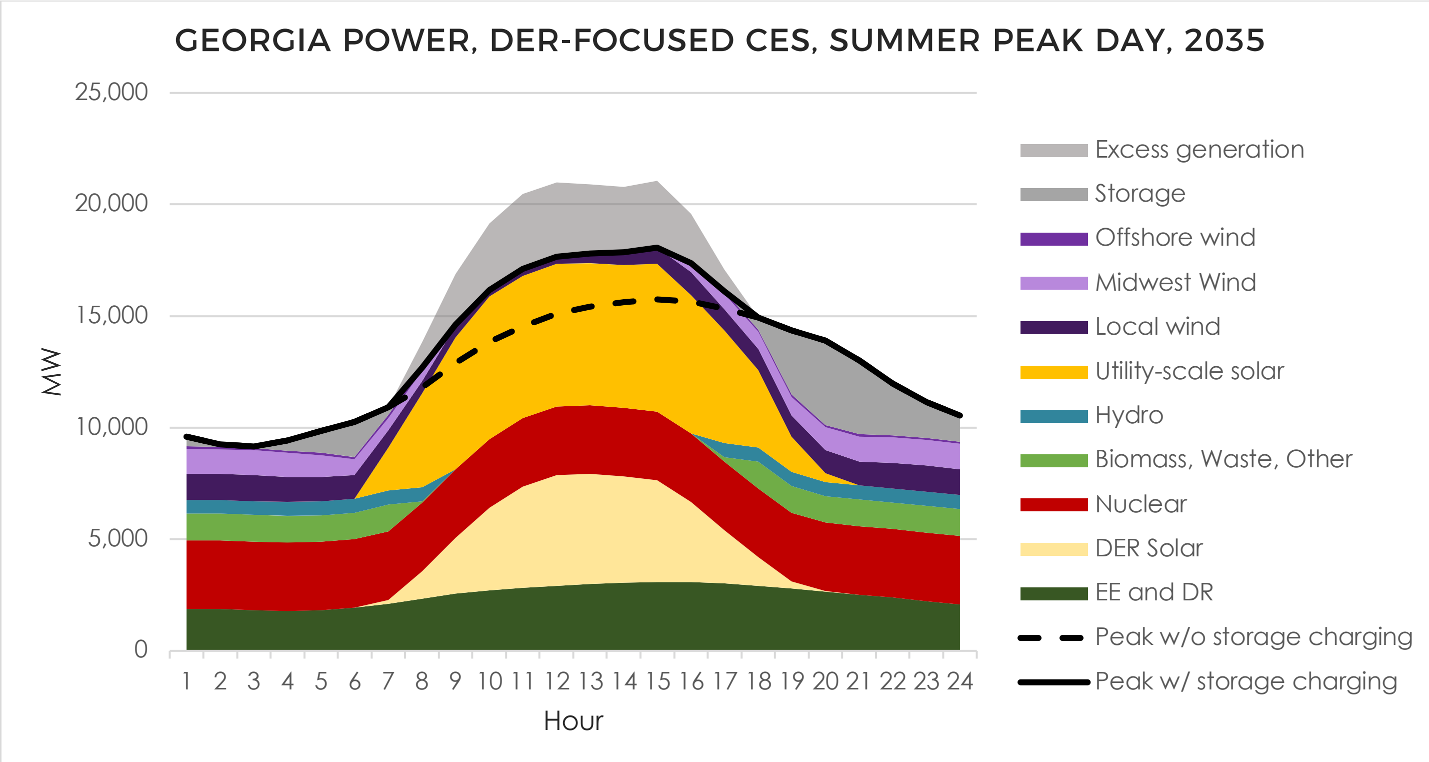
Southern Company

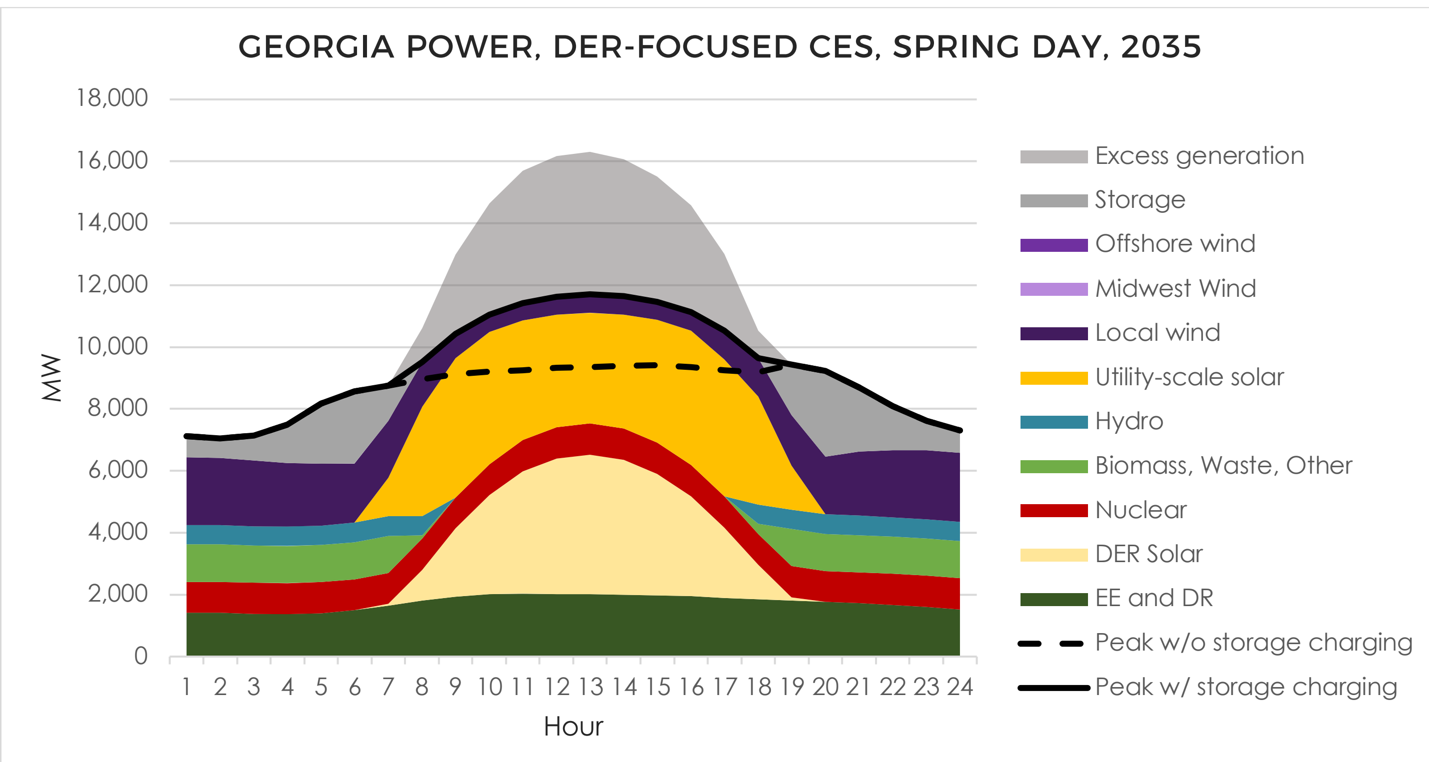


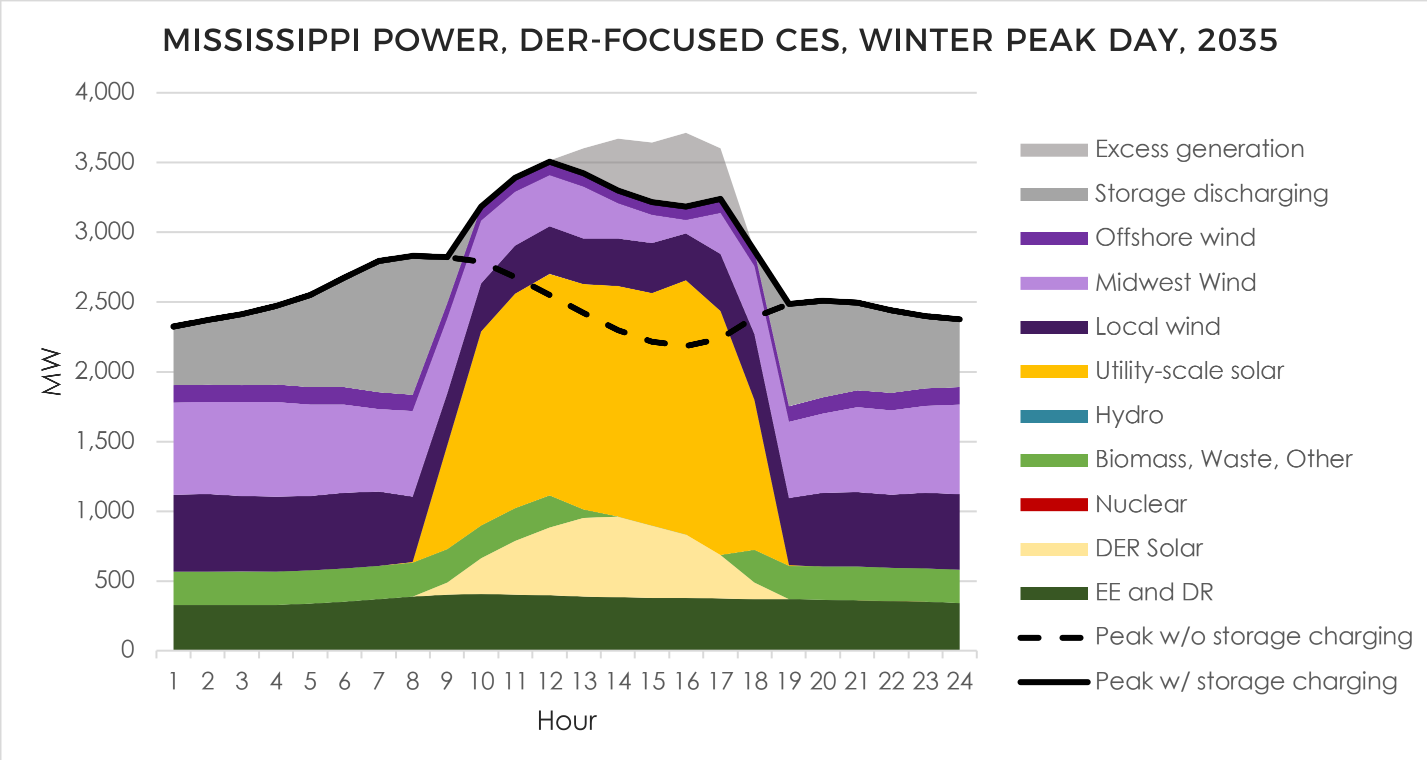


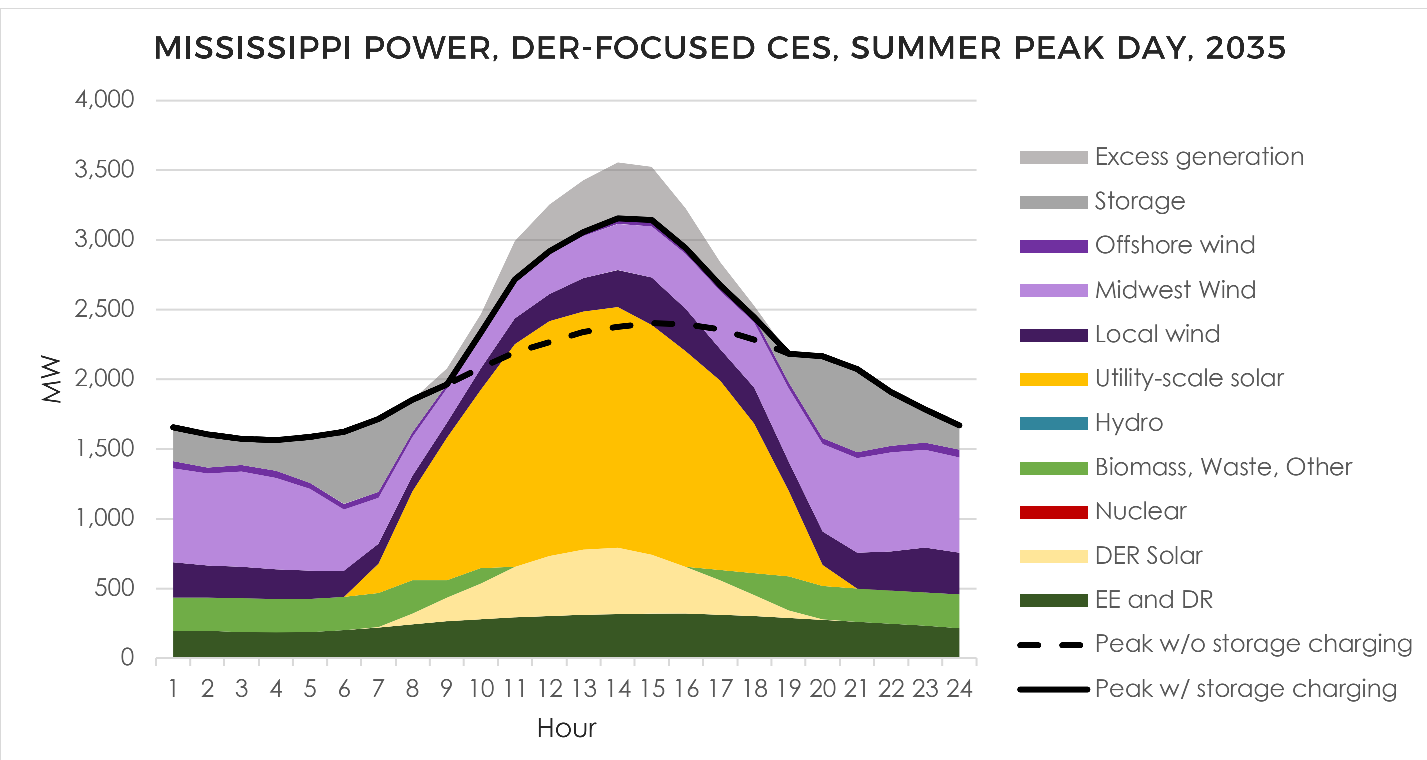

ALABAMA POWER, DER-FOCUSED CES, SPRING DAY, 2035
12,000
10,000
8,000
6,000
4,000
2,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

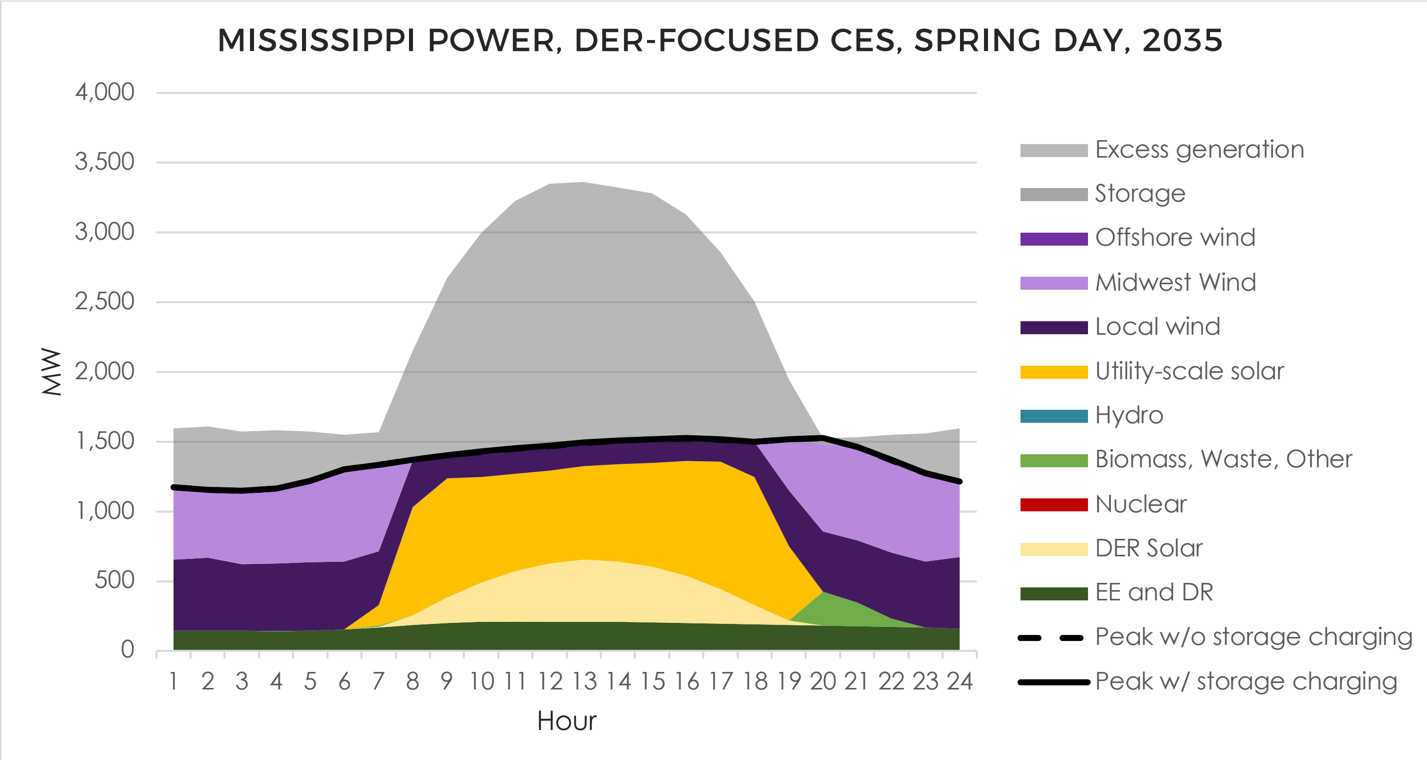

GEORGIA POWER, DER-FOCUSED CES, WINTER PEAK DAY, 2035
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage discharging
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging


GEORGIA POWER, DER-FOCUSED CES, SUMMER PEAK DAY, 2035
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging


GEORGIA POWER, DER-FOCUSED CES, SPRING DAY, 2035
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

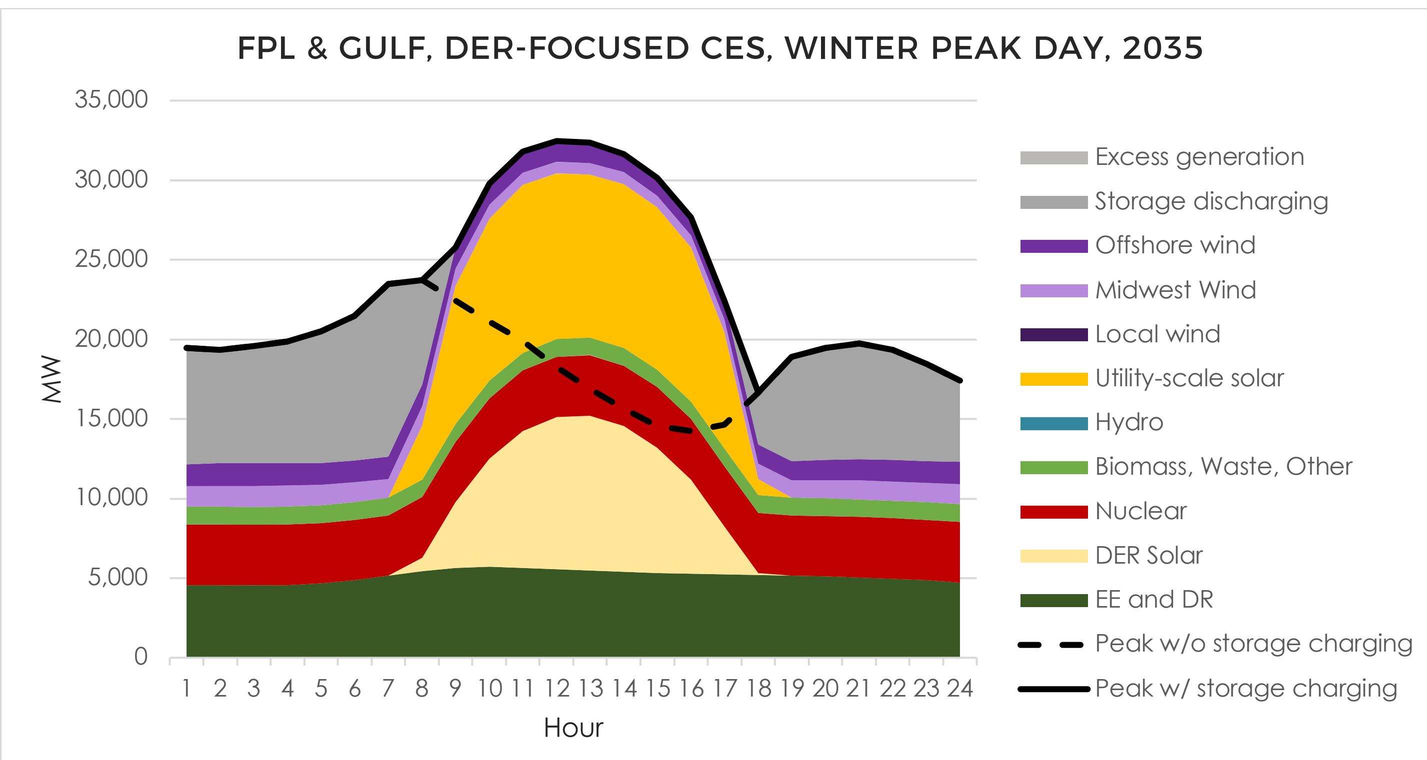

MISSISSIPPI POWER, DER-FOCUSED CES, WINTER PEAK DAY, 2035
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage discharging
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging


MISSISSIPPI POWER, DER-FOCUSED CES, SUMMER PEAK DAY, 2035
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

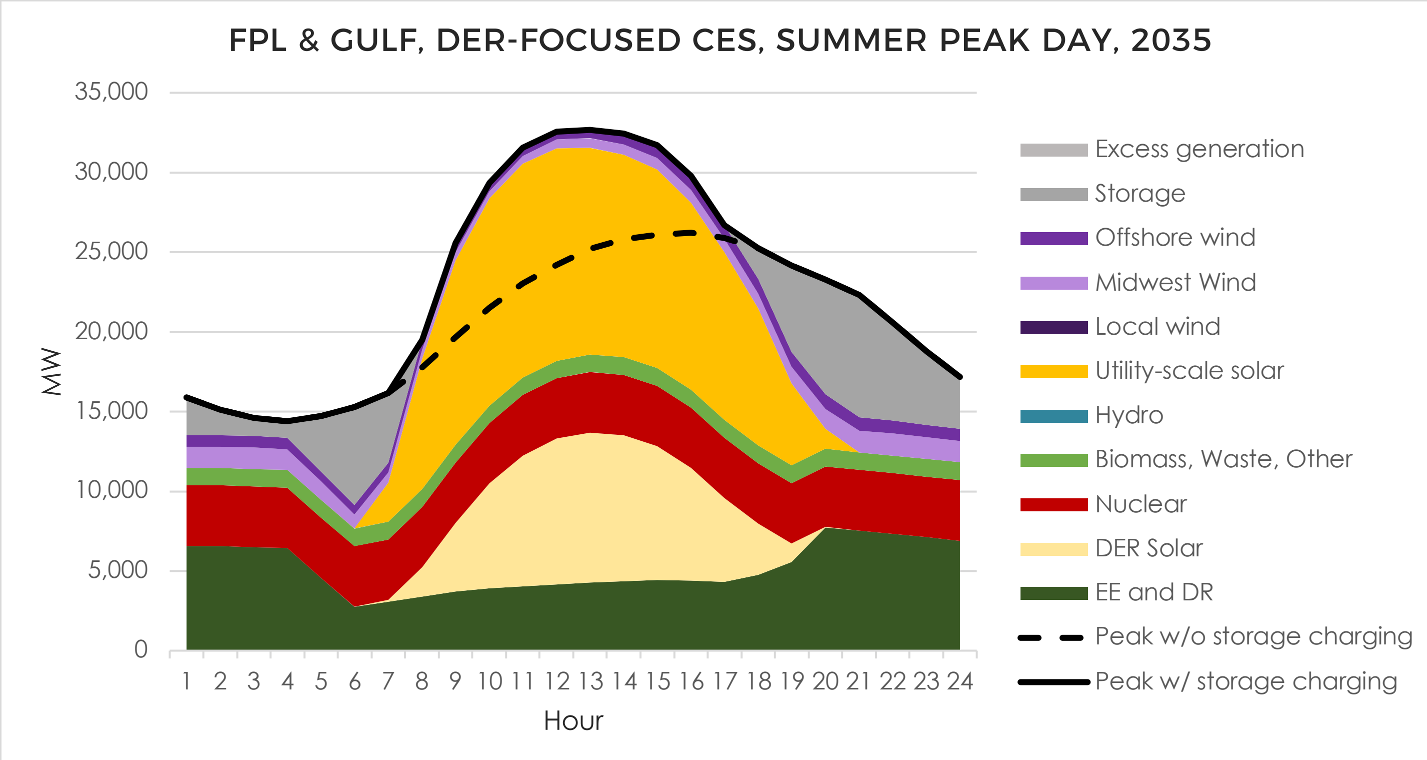


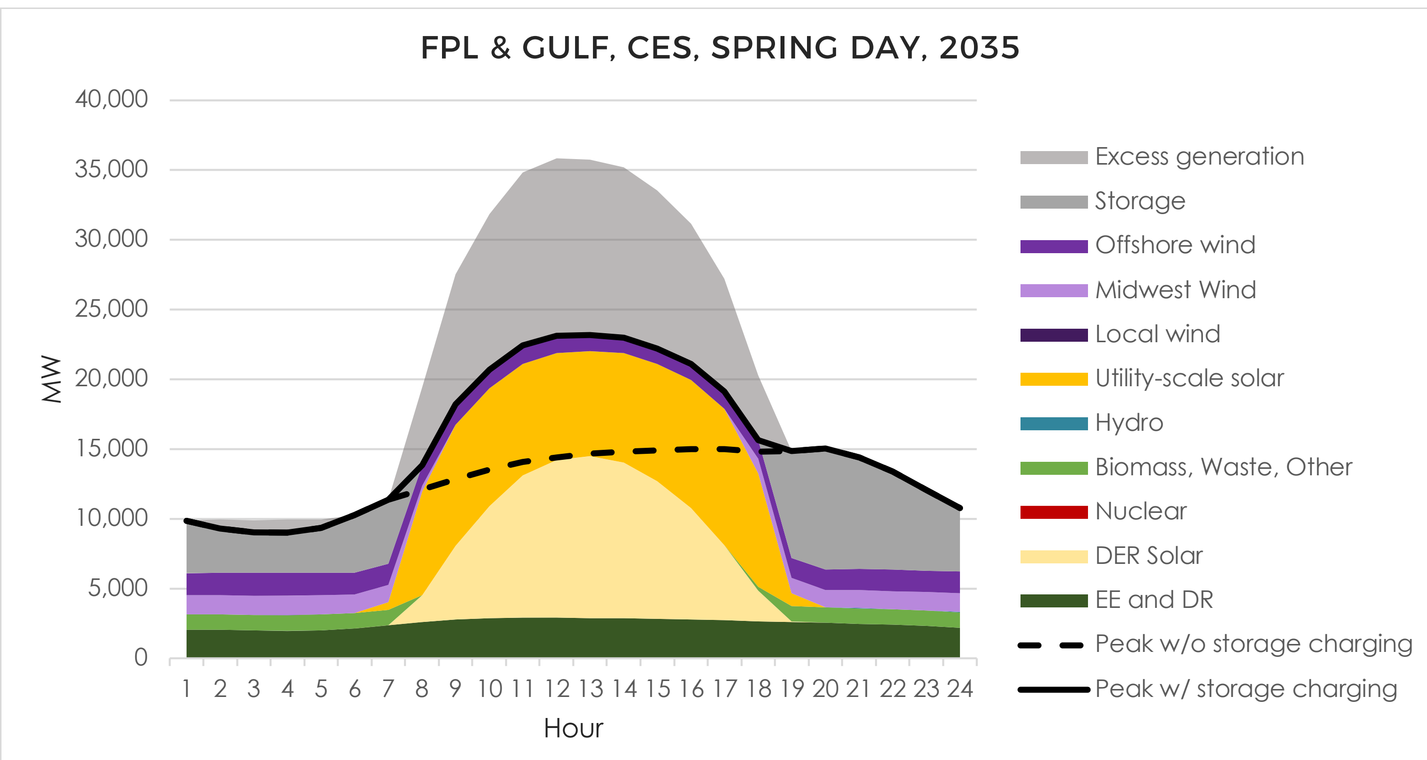
MISSISSIPPI POWER, DER-FOCUSED CES, SPRING DAY, 2035
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

NextEra



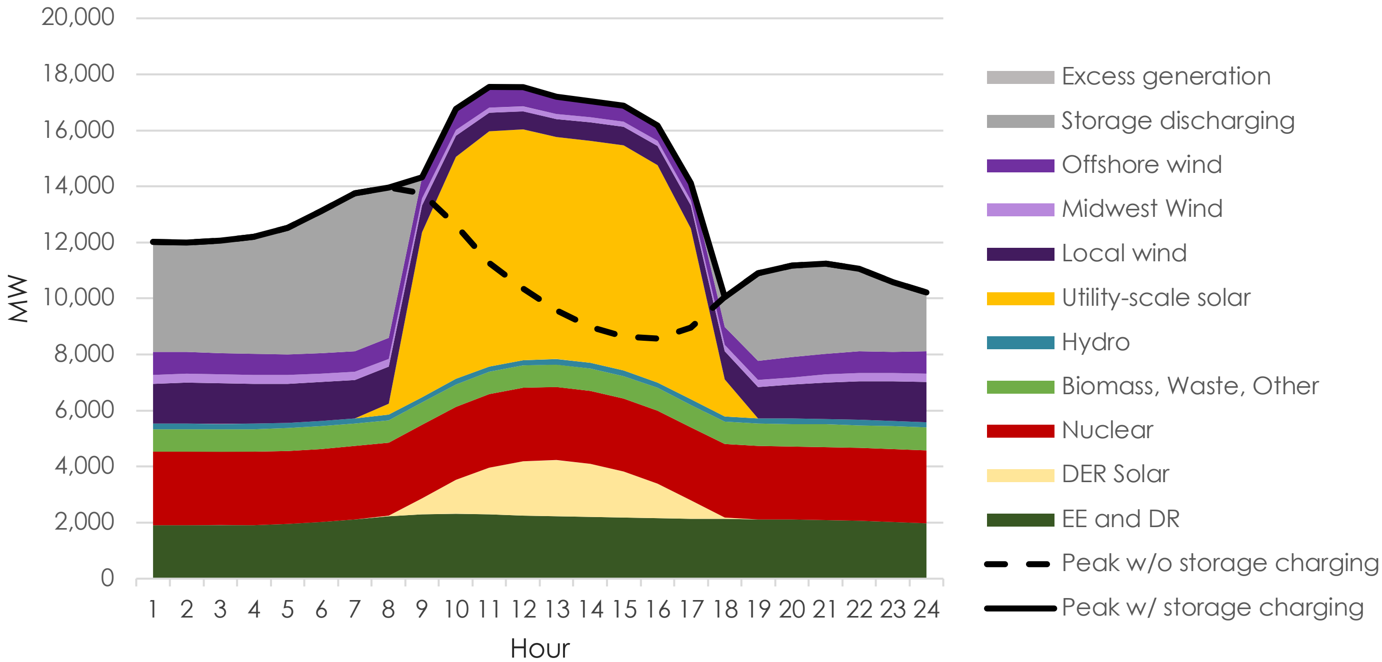
FPL & GULF, DER-FOCUSED CES, WINTER PEAK DAY, 2035
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage discharging
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging


FPL & GULF, DER-FOCUSED CES, SUMMER PEAK DAY, 2035
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

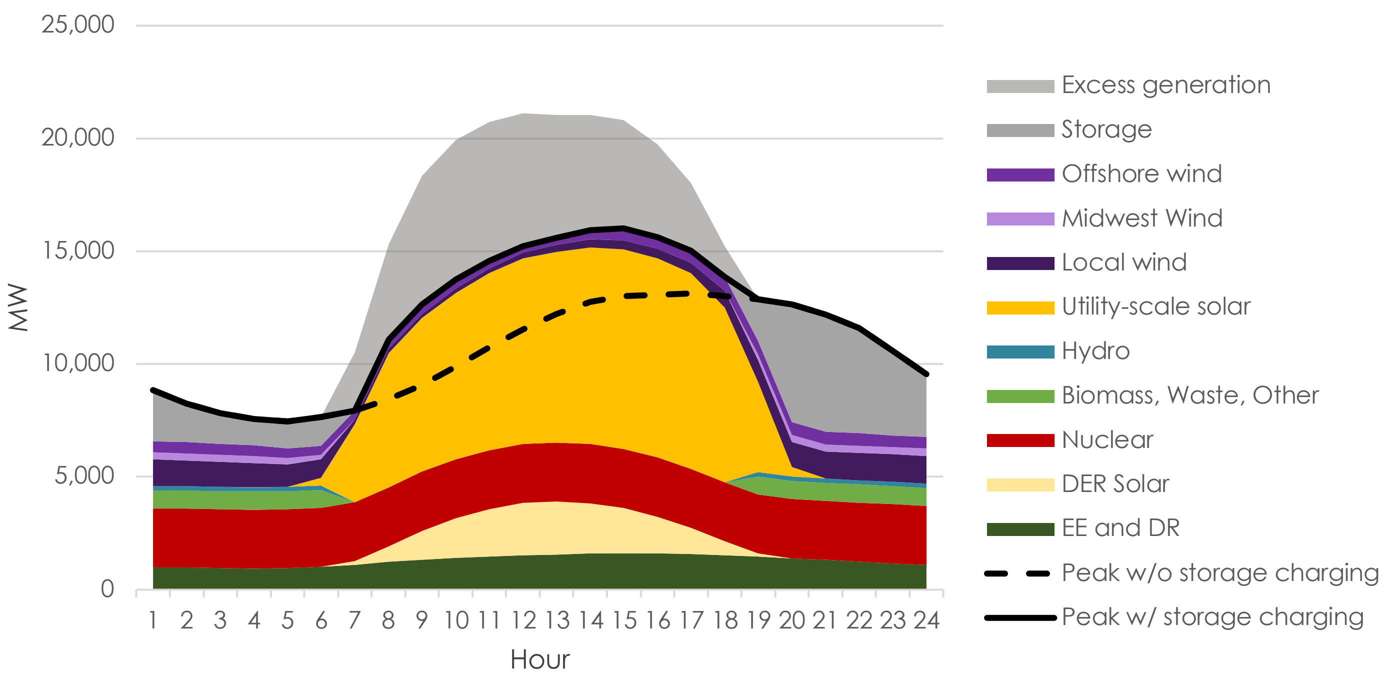

FPL & GULF, CES, SPRING DAY, 2035
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

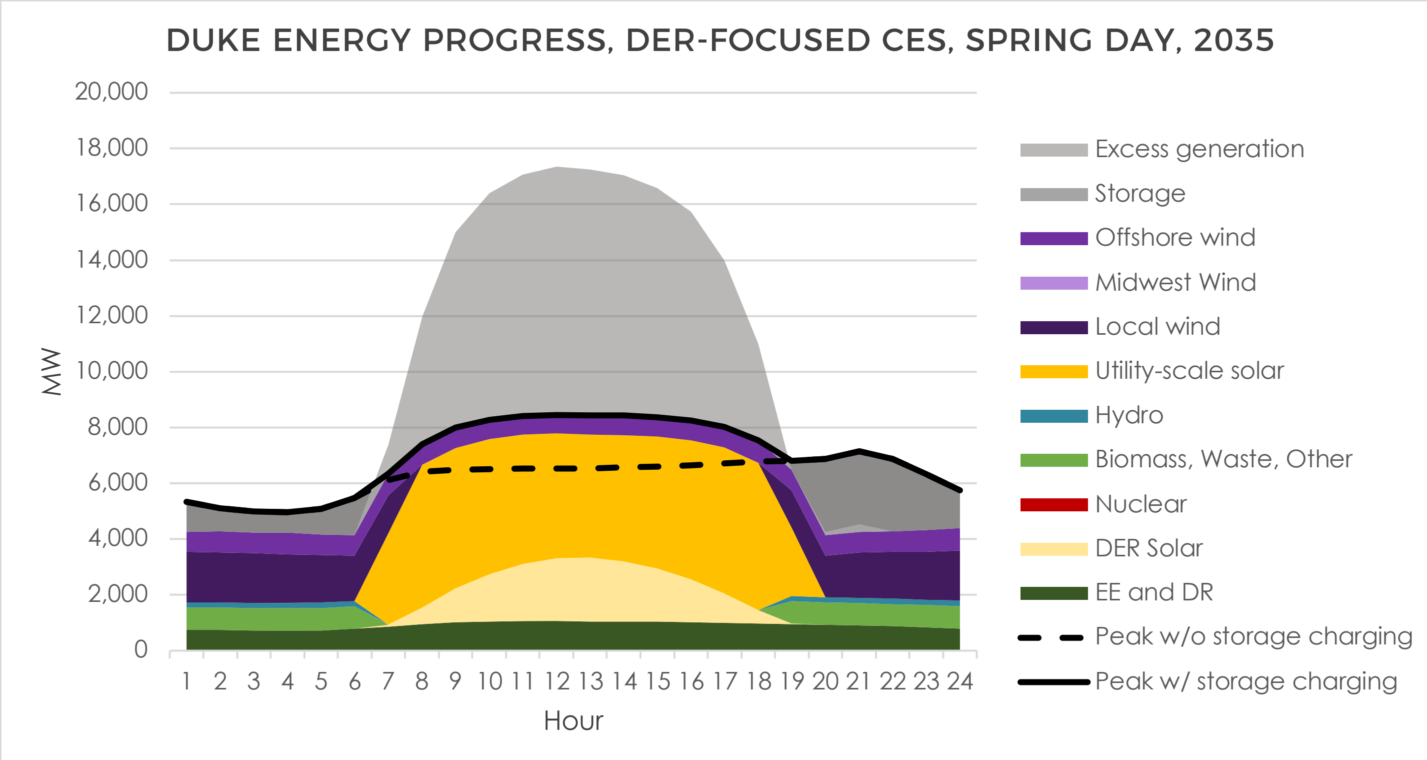
Duke Energy

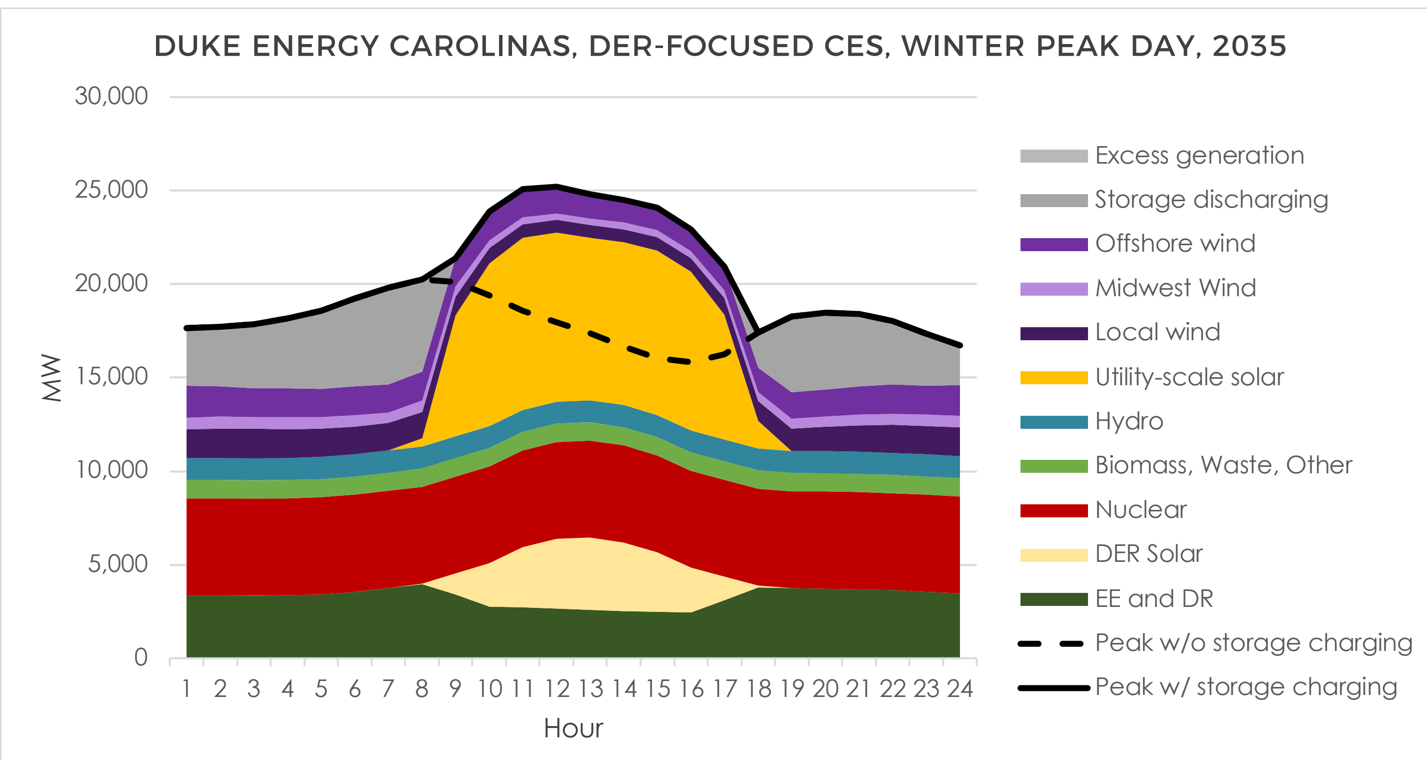
DUKE ENERGY PROGRESS, DER-FOCUSED CES, WINTER PEAK DAY, 2035



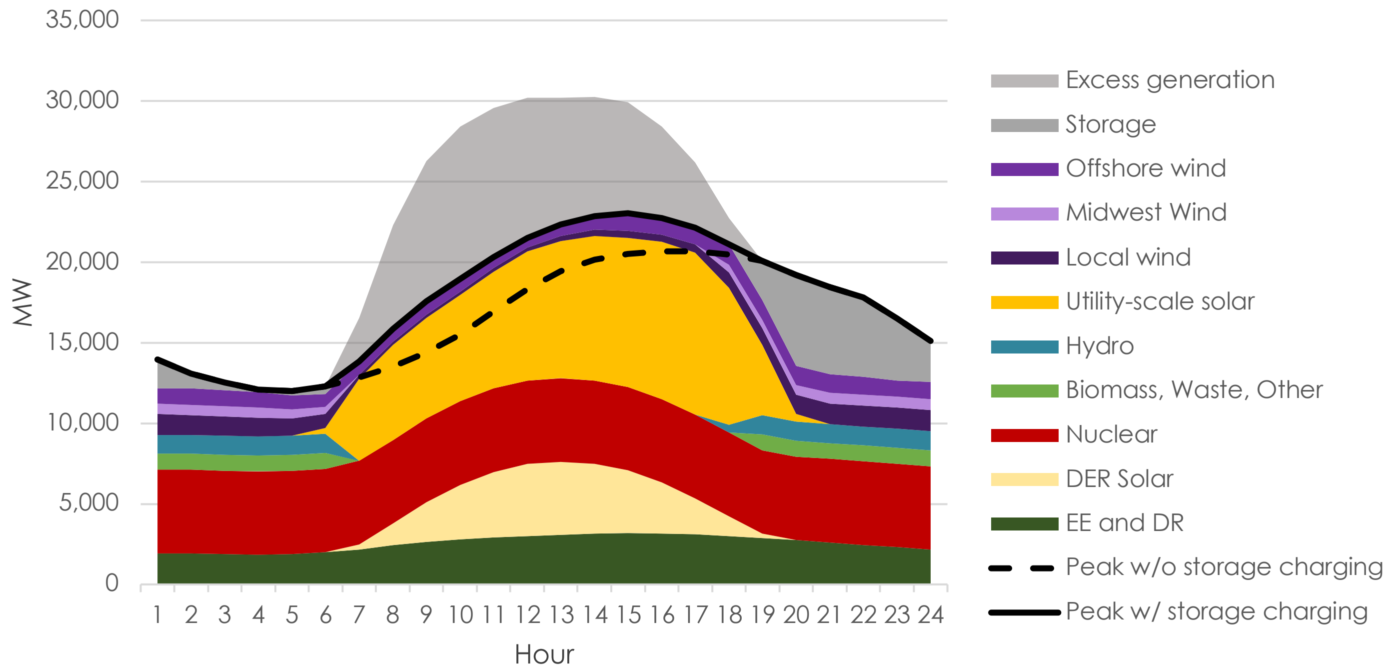
DUKE ENERGY PROGRESS, DER-FOCUSED CES, SUMMER PEAK DAY, 2035



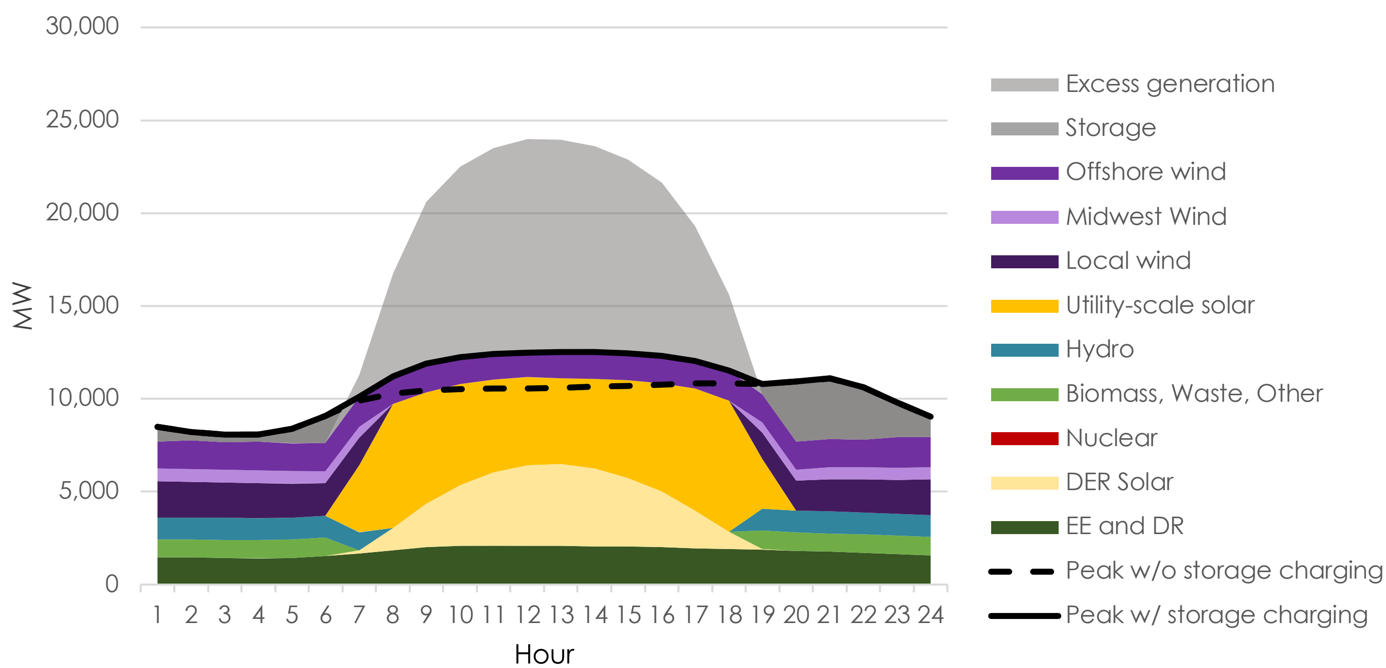

DUKE ENERGY PROGRESS, DER-FOCUSED CES, SPRING DAY, 2035
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

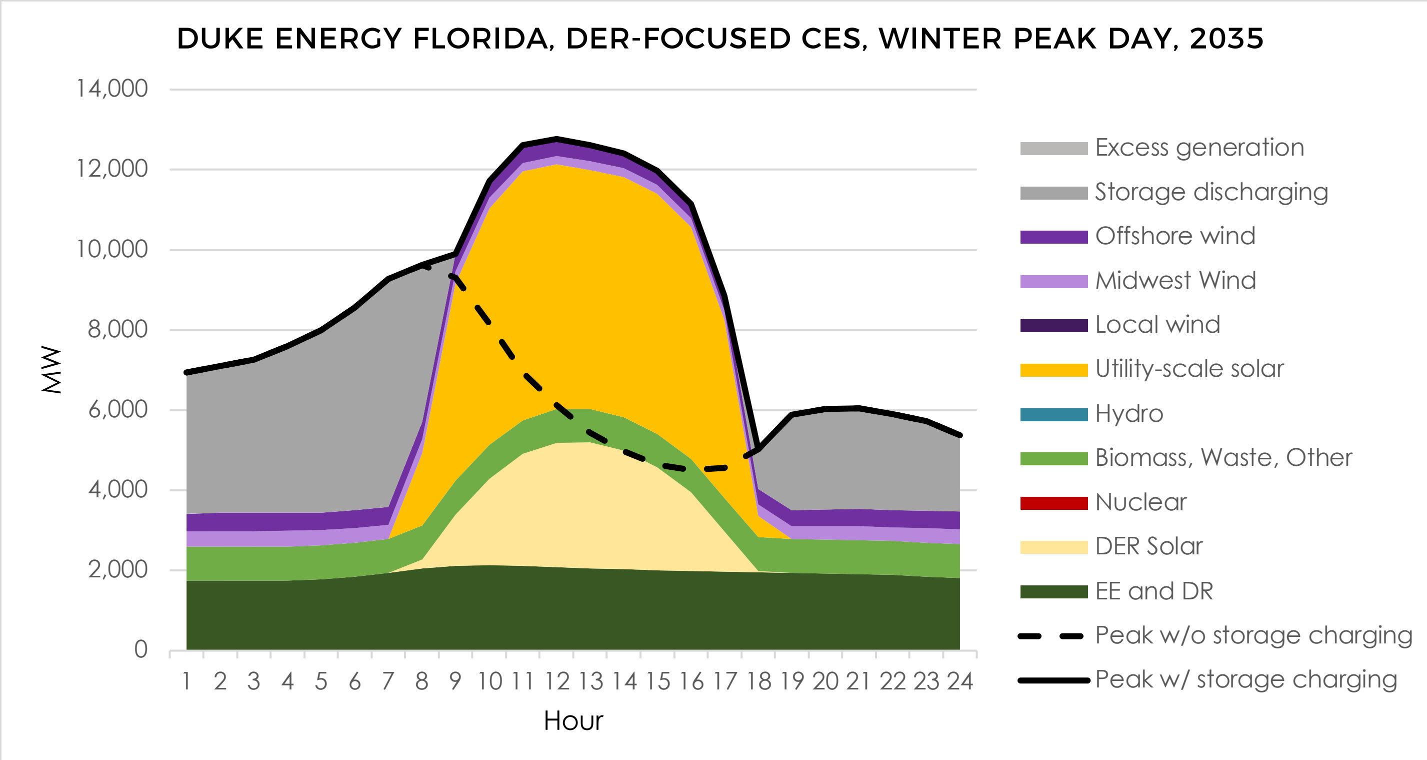

DUKE ENERGY CAROLINAS, DER-FOCUSED CES, WINTER PEAK DAY, 2035
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage discharging
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

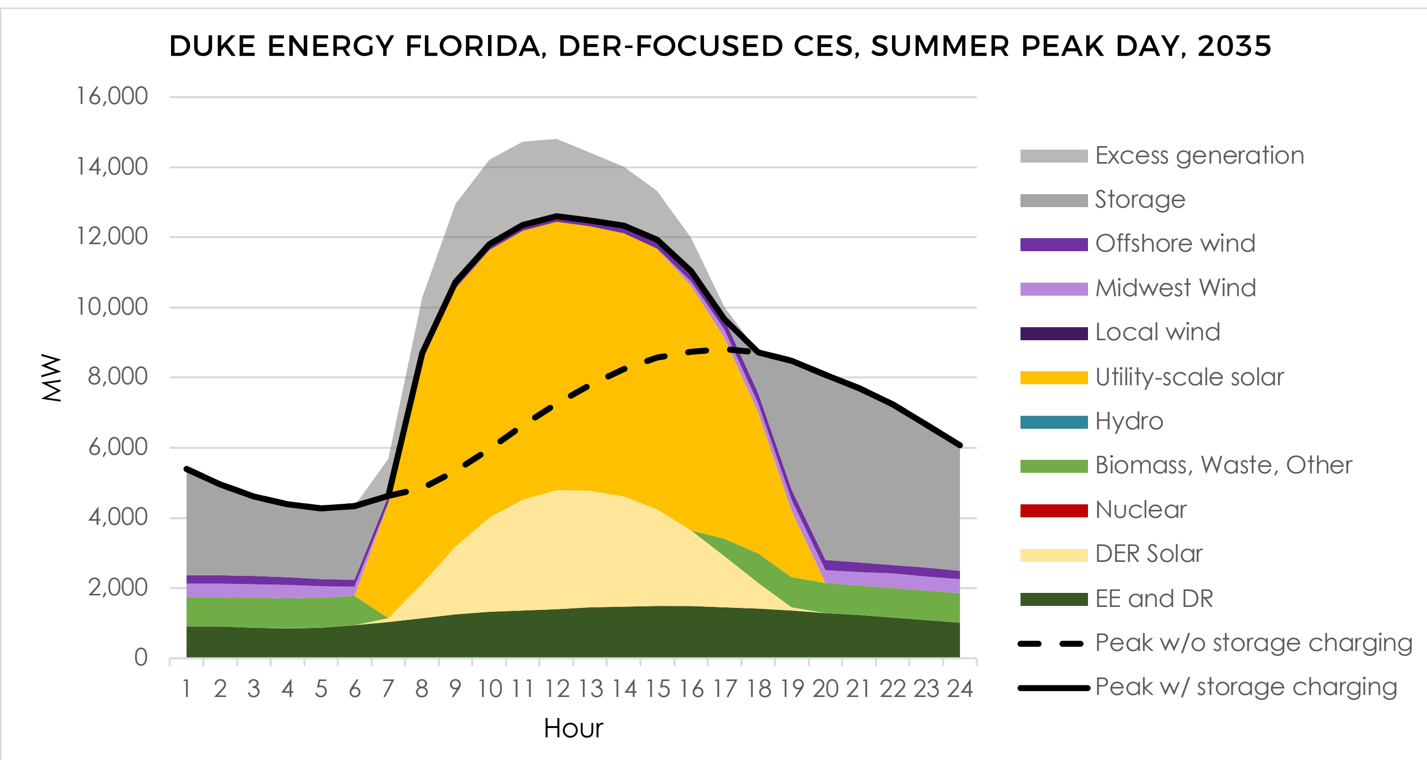
DUKE ENERGY CAROLINAS, DER-FOCUSED CES, SUMMER PEAK DAY, 2035

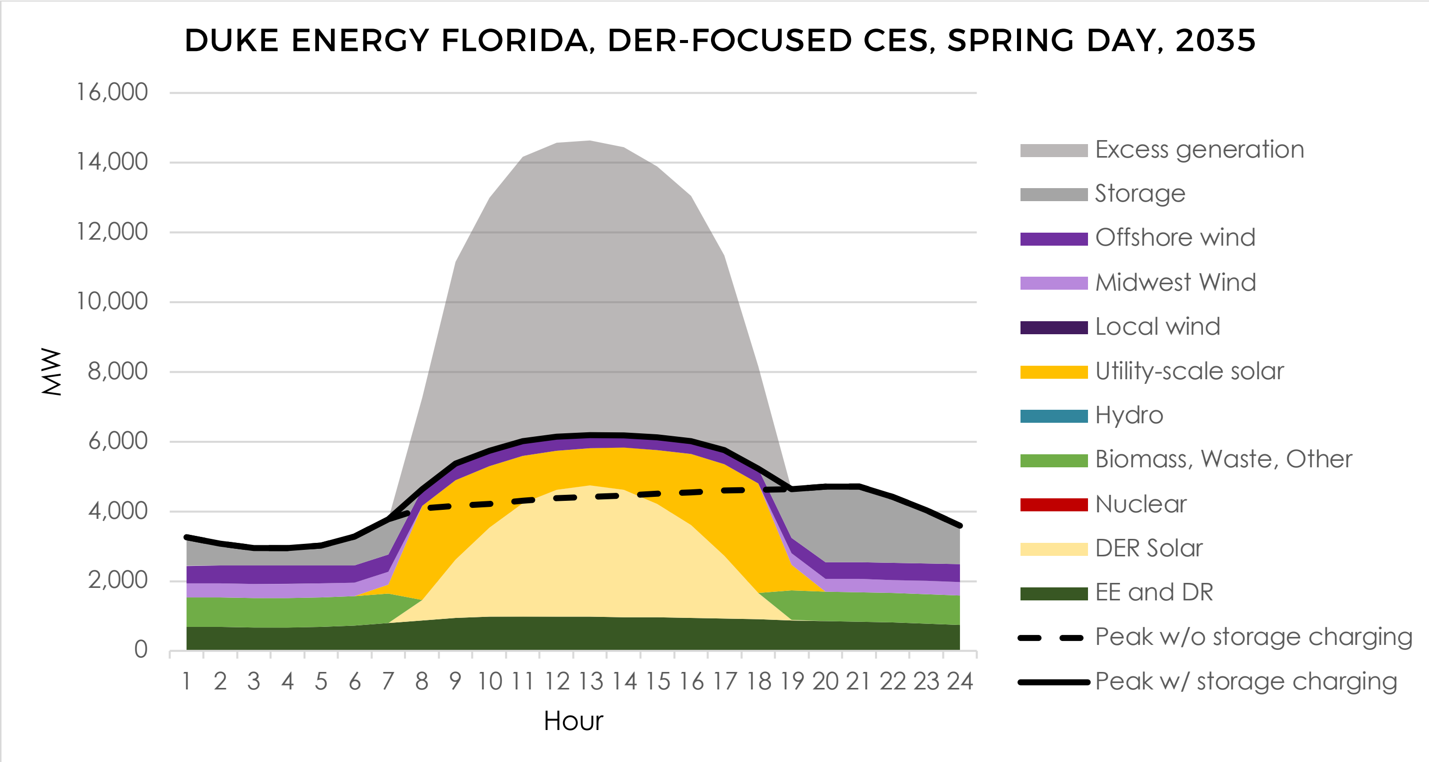


DUKE ENERGY CAROLINAS, DER-FOCUSED CES, SPRING DAY, 2035

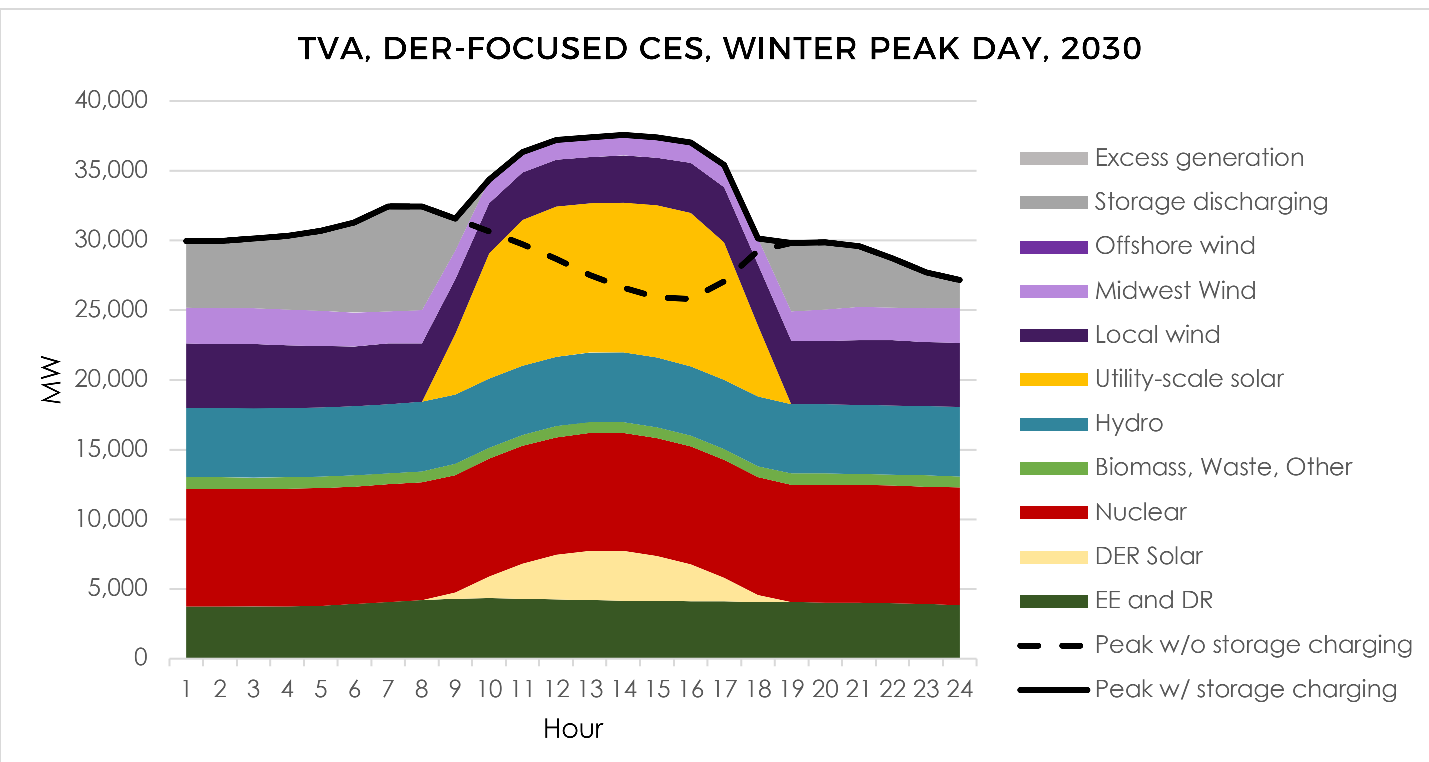


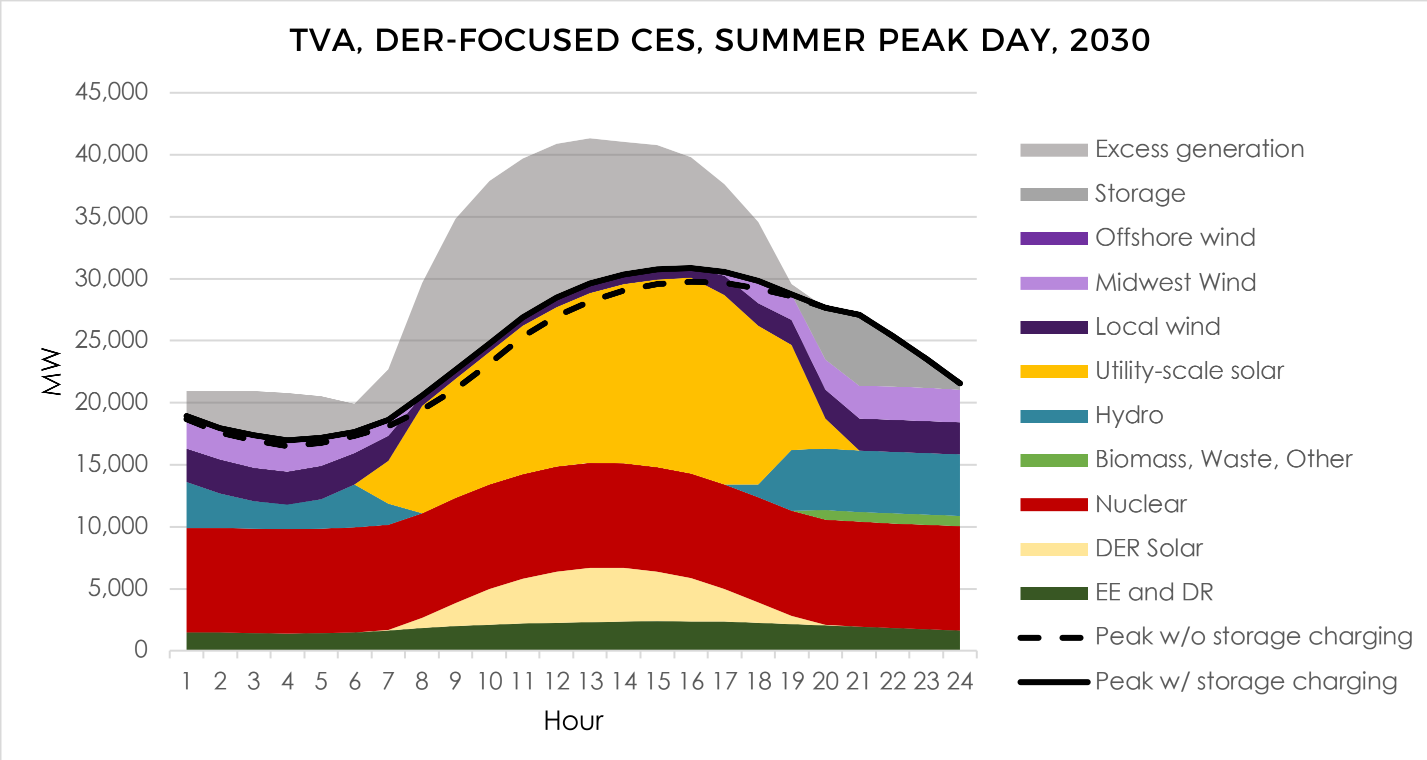

DUKE ENERGY FLORIDA, DER-FOCUSED CES, WINTER PEAK DAY, 2035
MW
Hour
0
2,000
4,000
6,000
8,000
10,000
12,000
14,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Excess generation
Storage discharging
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

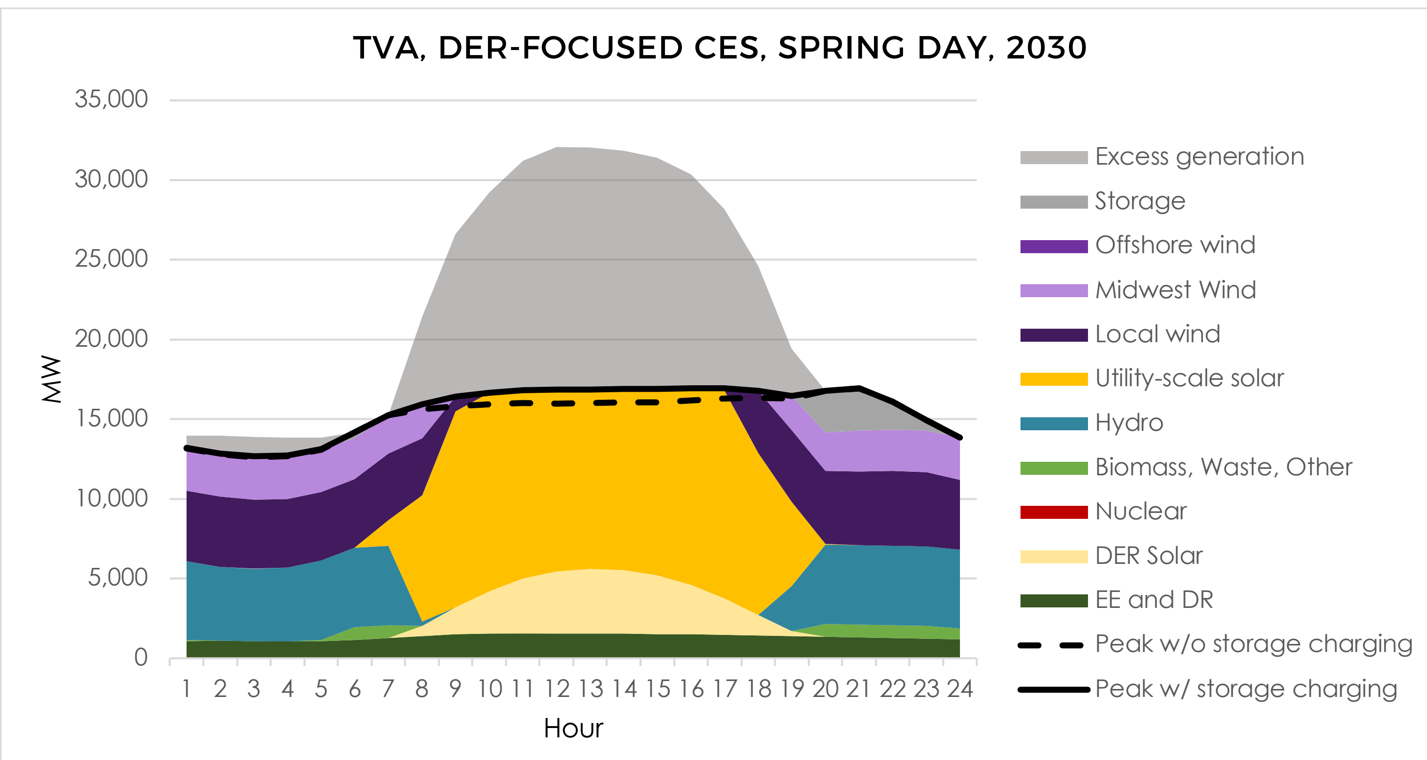

DUKE ENERGY FLORIDA, DER-FOCUSED CES, SUMMER PEAK DAY, 2035
MW
Hour
0
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging



Tennessee Valley Authority

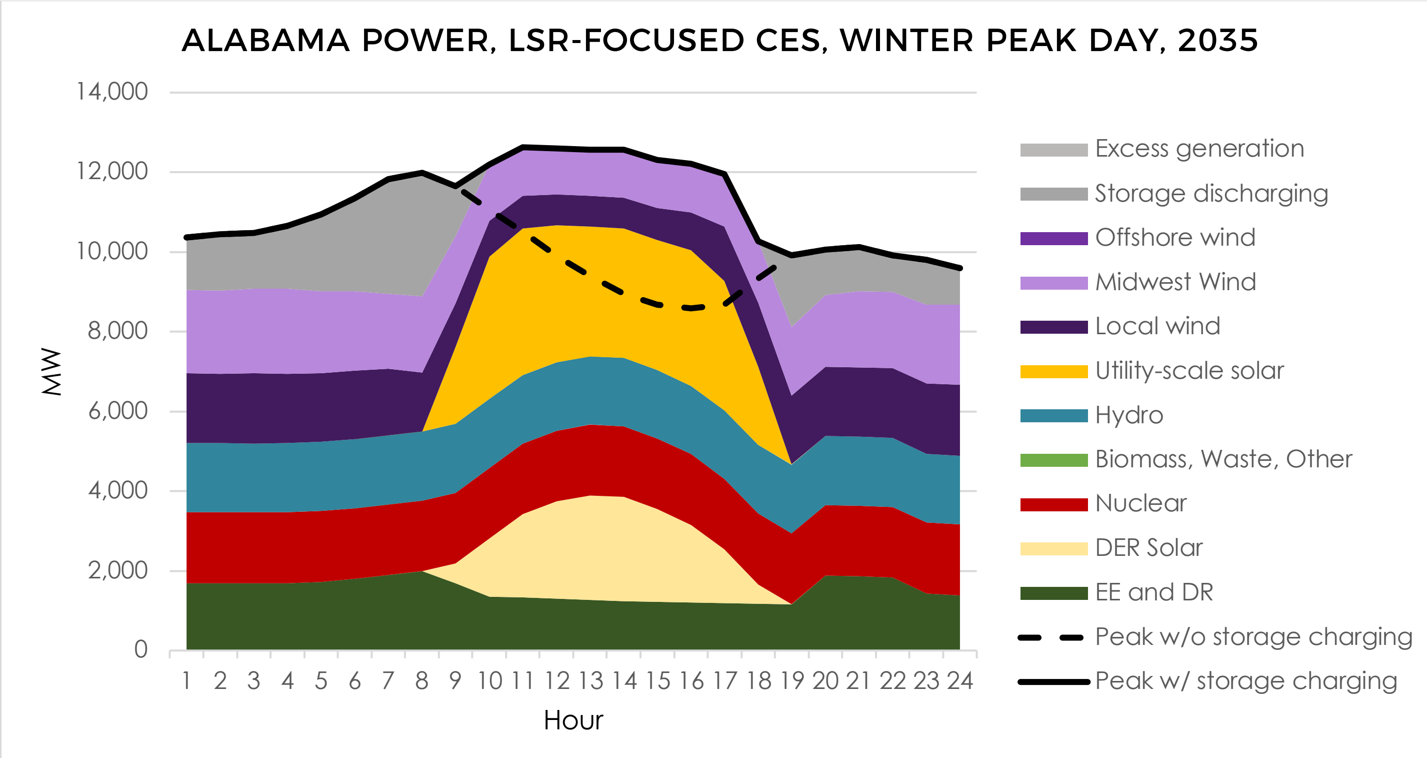


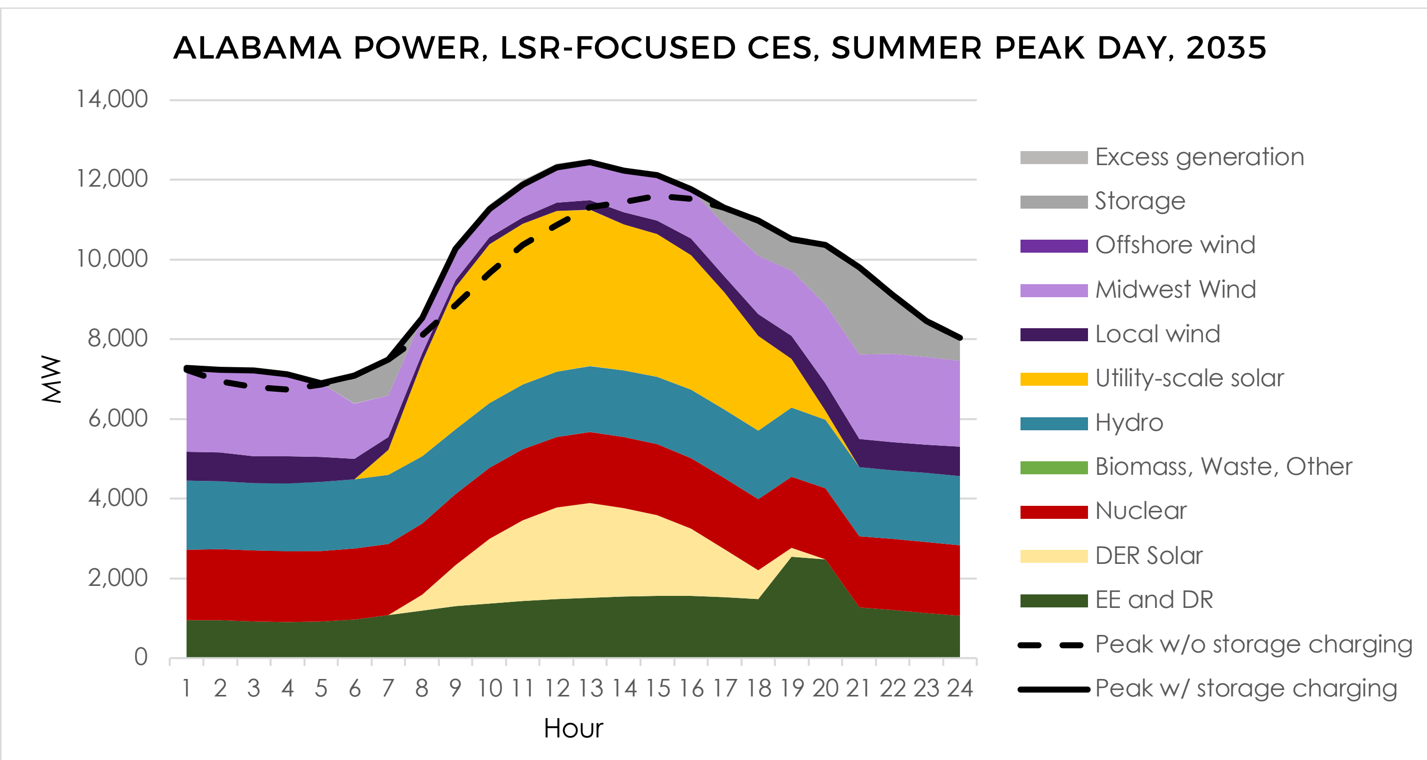

TVA, DER-FOCUSED CES, SUMMER PEAK DAY, 2030
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

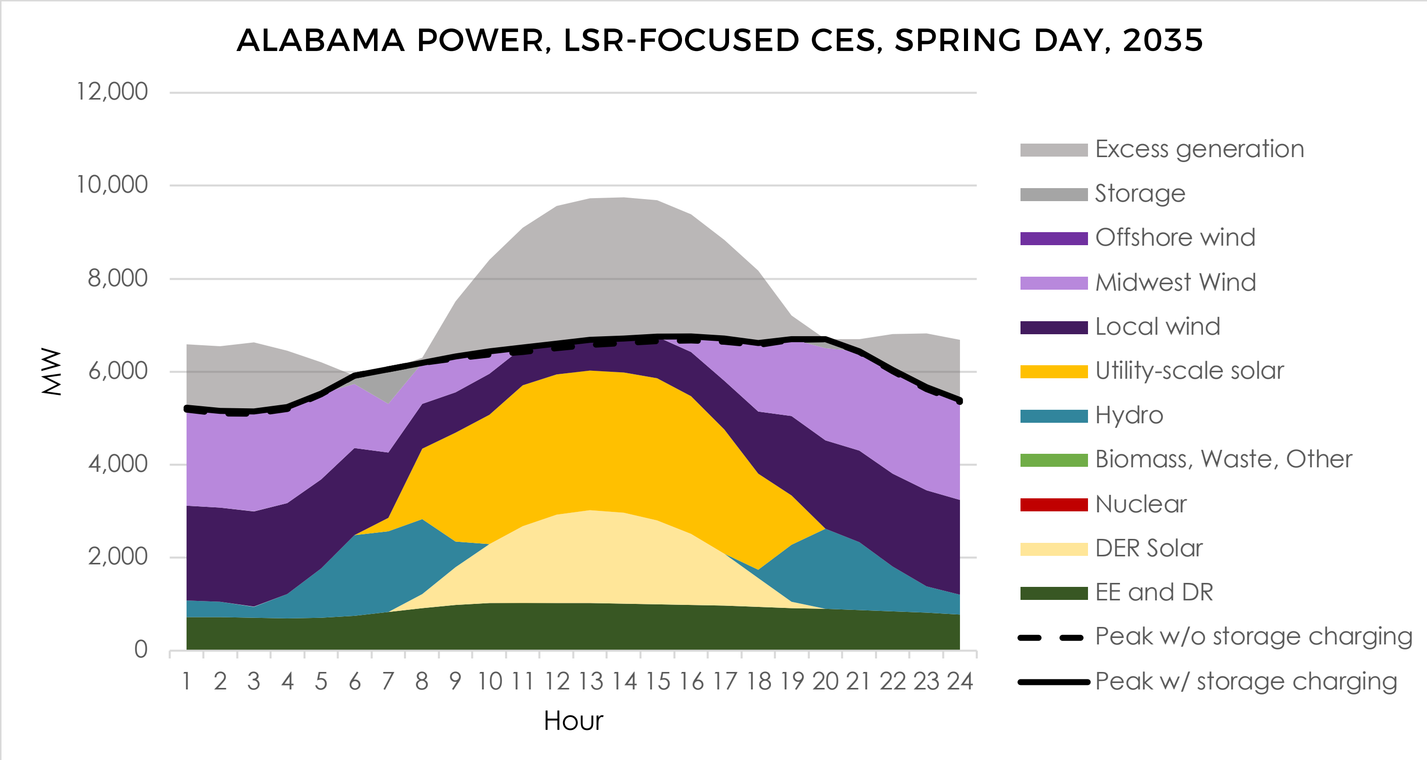

TVA, DER-FOCUSED CES, SPRING DAY, 2030
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

LARGE-SCALE RENEWABLE-FOCUSED CES

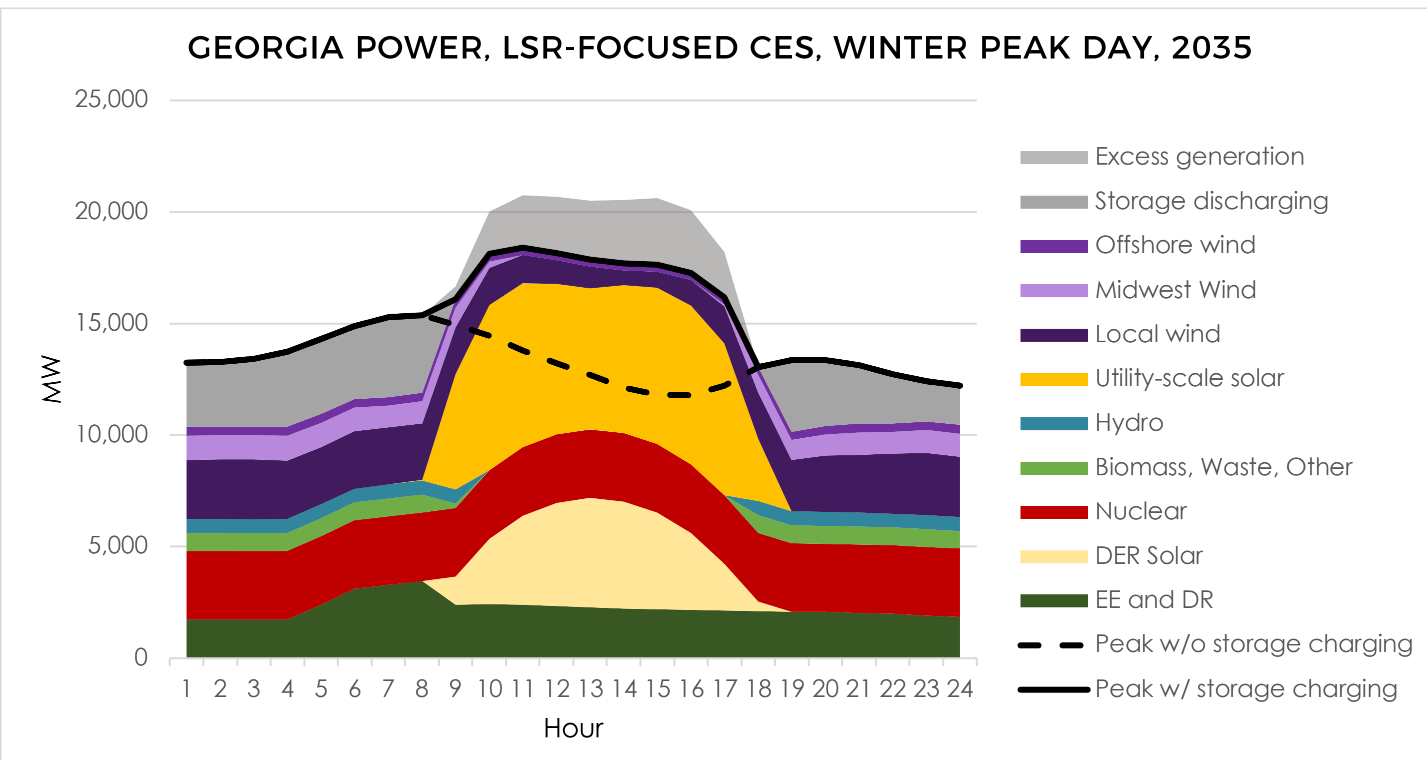
Southern Company



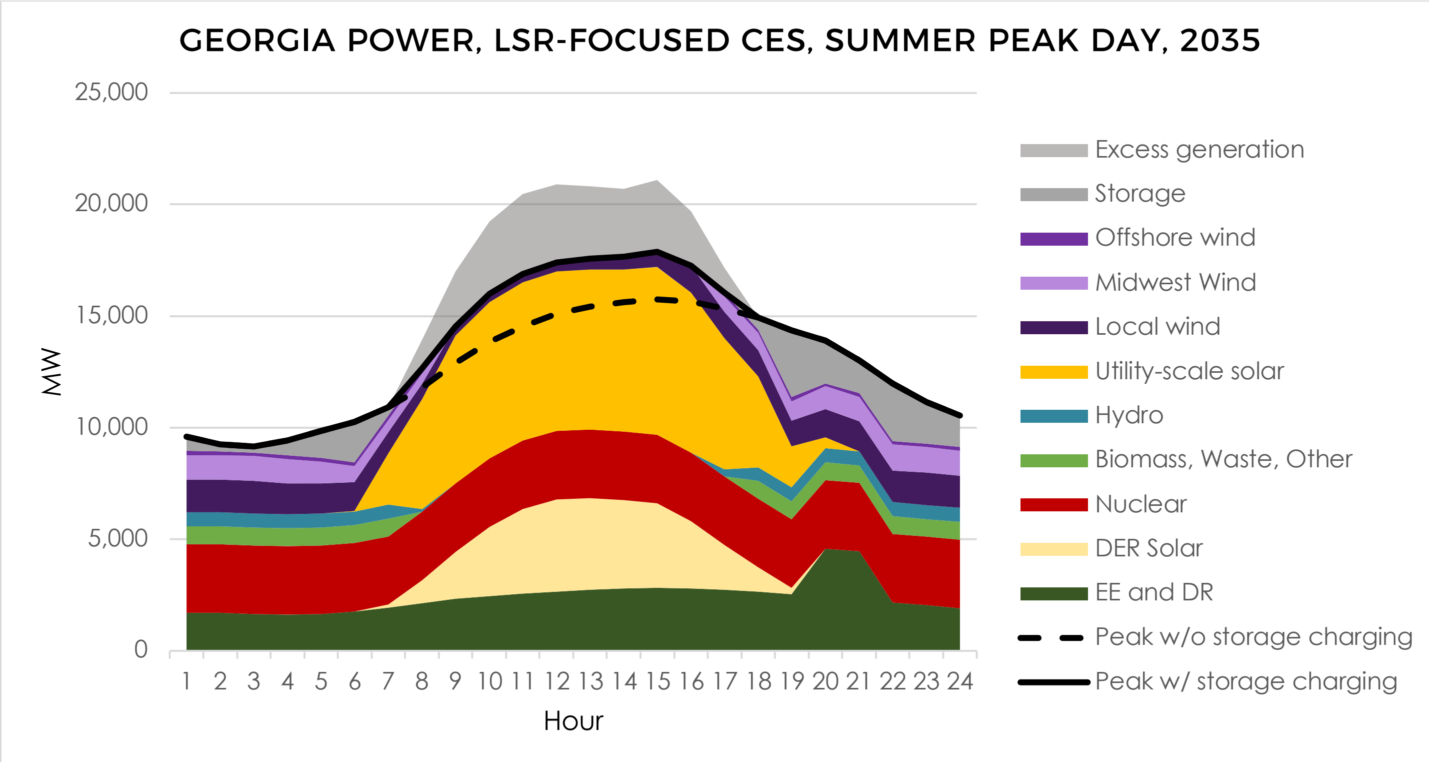


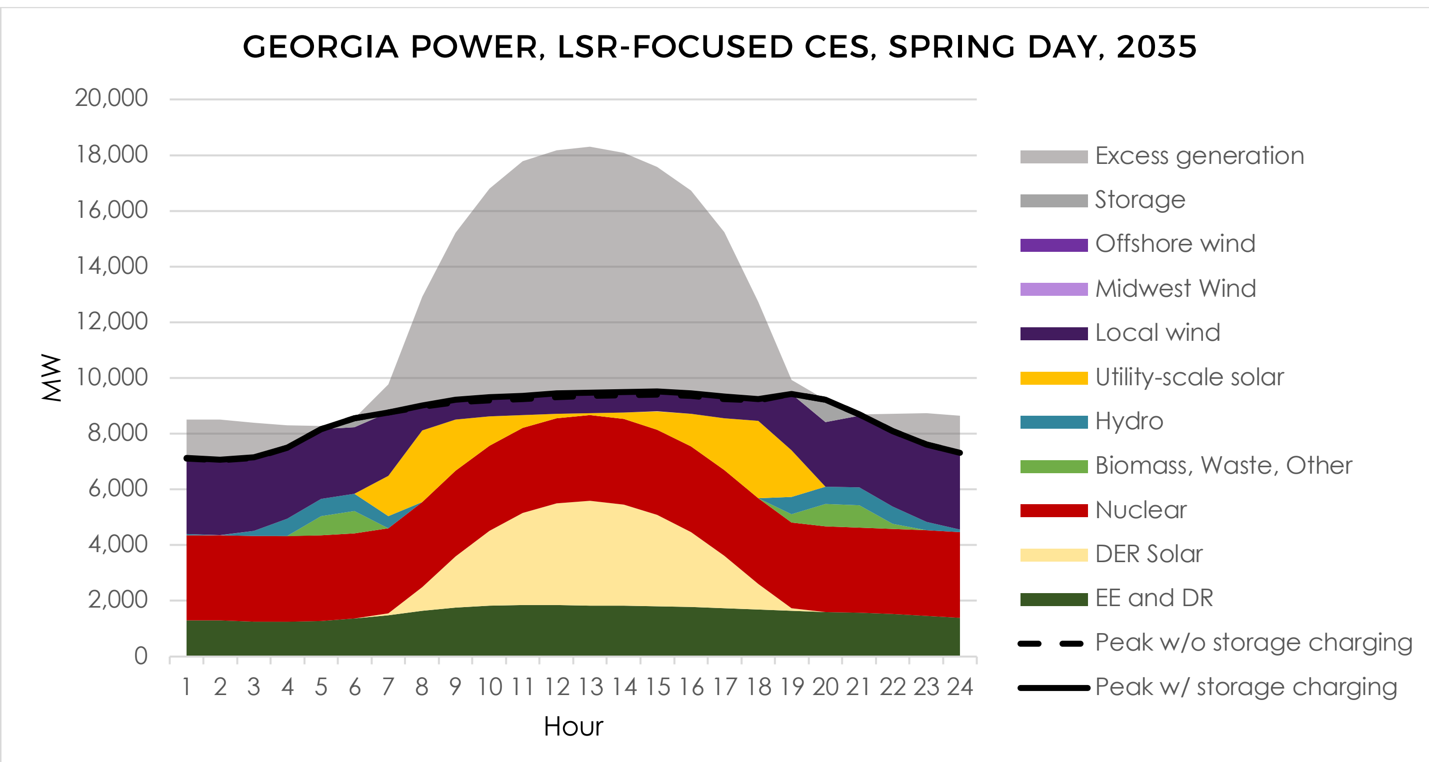


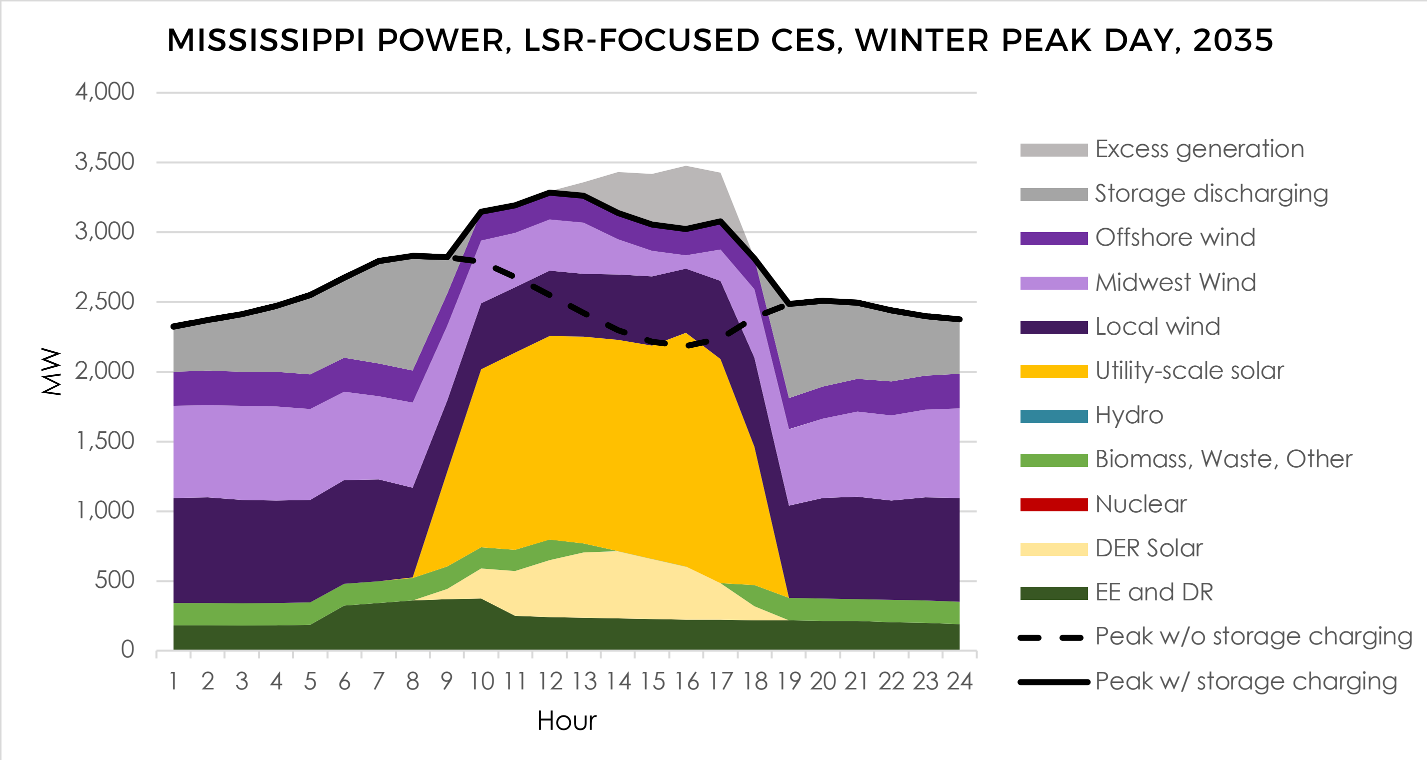
ALABAMA POWER, LSR-FOCUSED CES, SPRING DAY, 2035
12,000
10,000
8,000
6,000
4,000
2,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

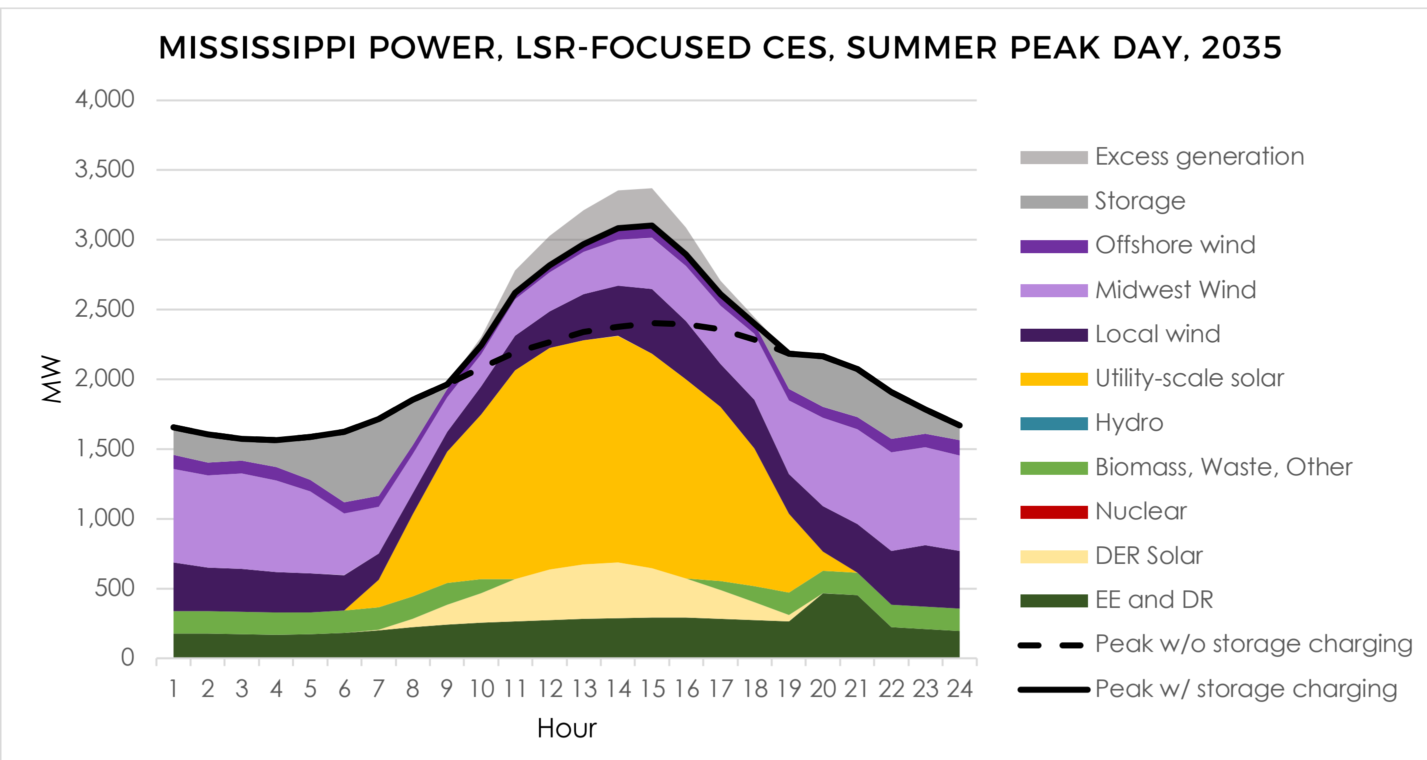


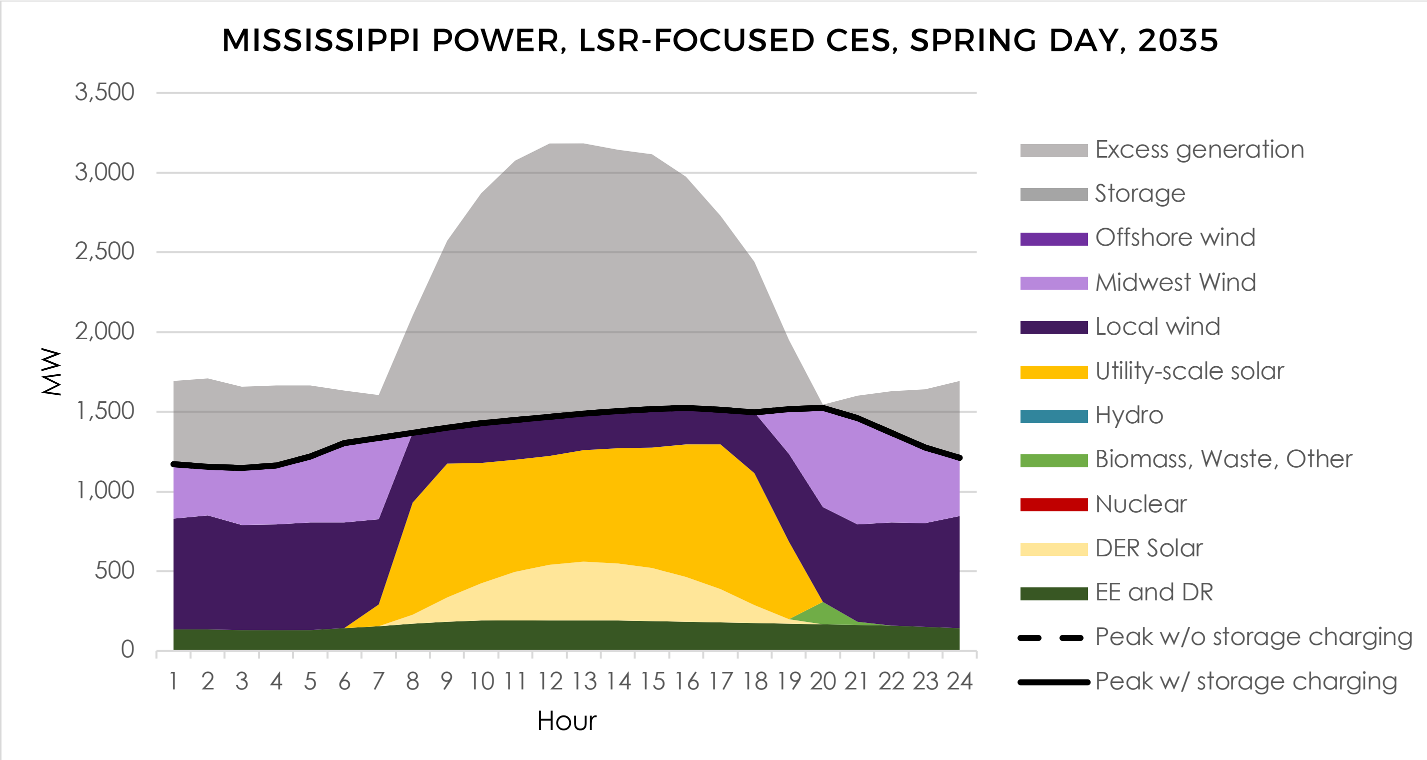
GEORGIA POWER, LSR-FOCUSED CES, WINTER PEAK DAY, 2035
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage discharging
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging


GEORGIA POWER, LSR-FOCUSED CES, SUMMER PEAK DAY, 2035
MW
25,000
20,000
15,000
10,000
5,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

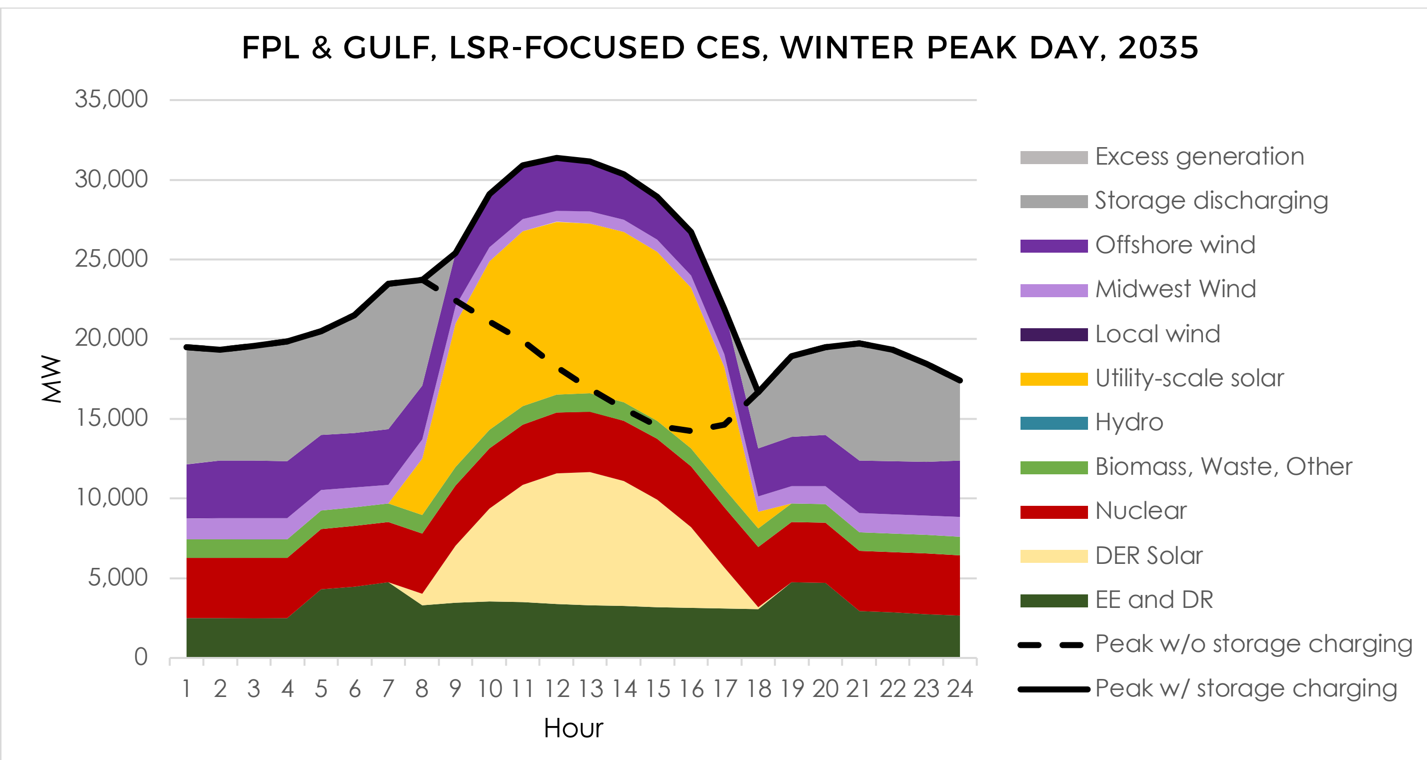

GEORGIA POWER, LSR-FOCUSED CES, SPRING DAY, 2035
MW
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

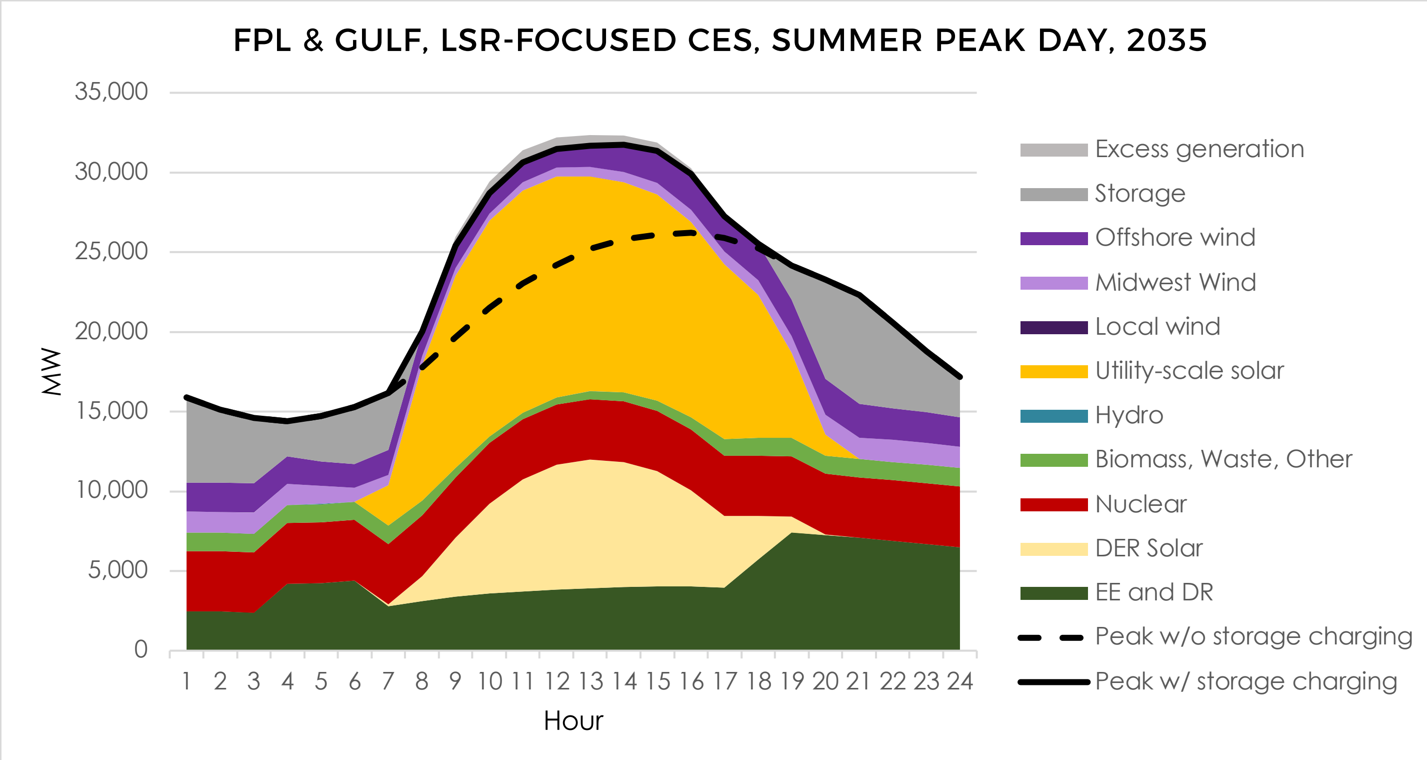

MISSISSIPPI POWER, LSR-FOCUSED CES, WINTER PEAK DAY, 2035
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage discharging
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

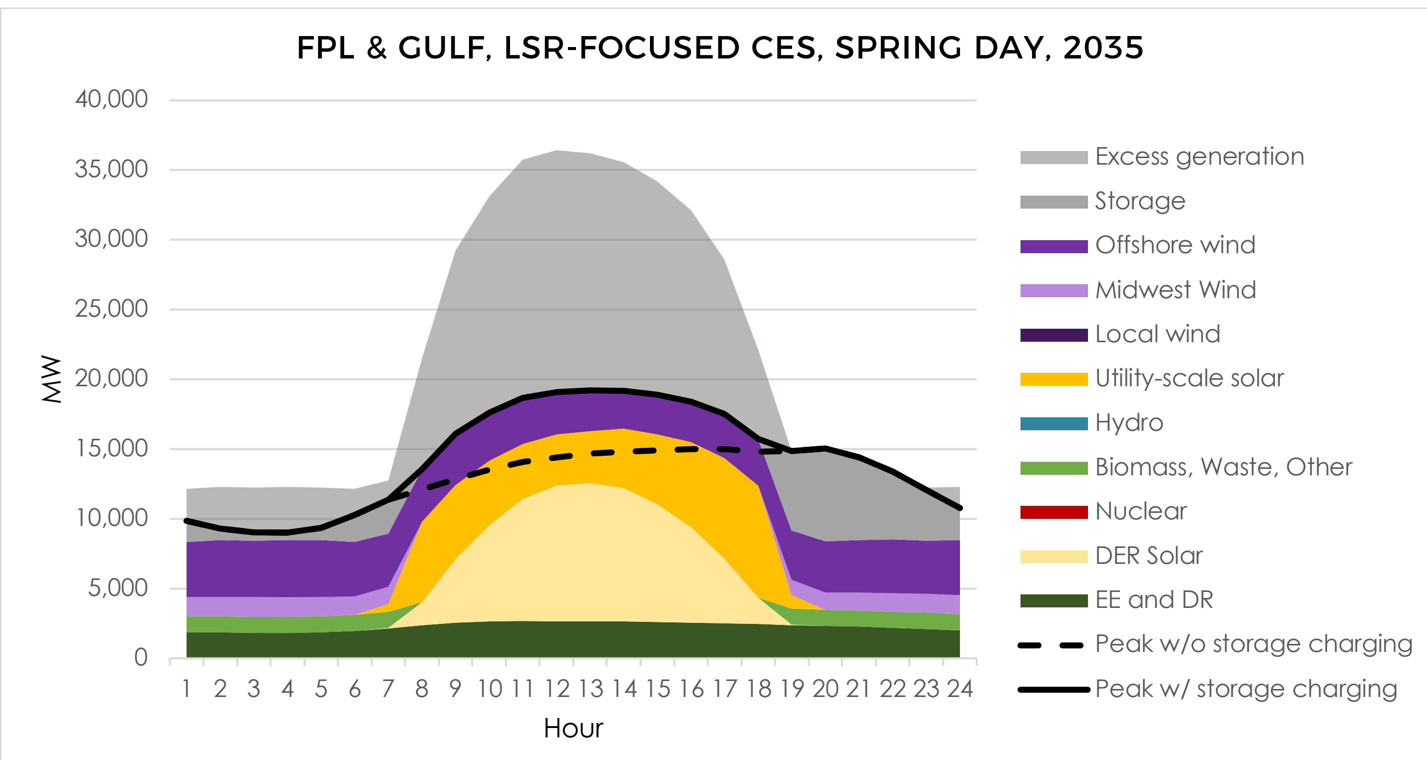

MISSISSIPPI POWER, LSR-FOCUSED CES, SUMMER PEAK DAY, 2035
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging


MISSISSIPPI POWER, LSR-FOCUSED CES, SPRING DAY, 2035
3,500
3,000
2,500
2,000
1,500
1,000
500
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

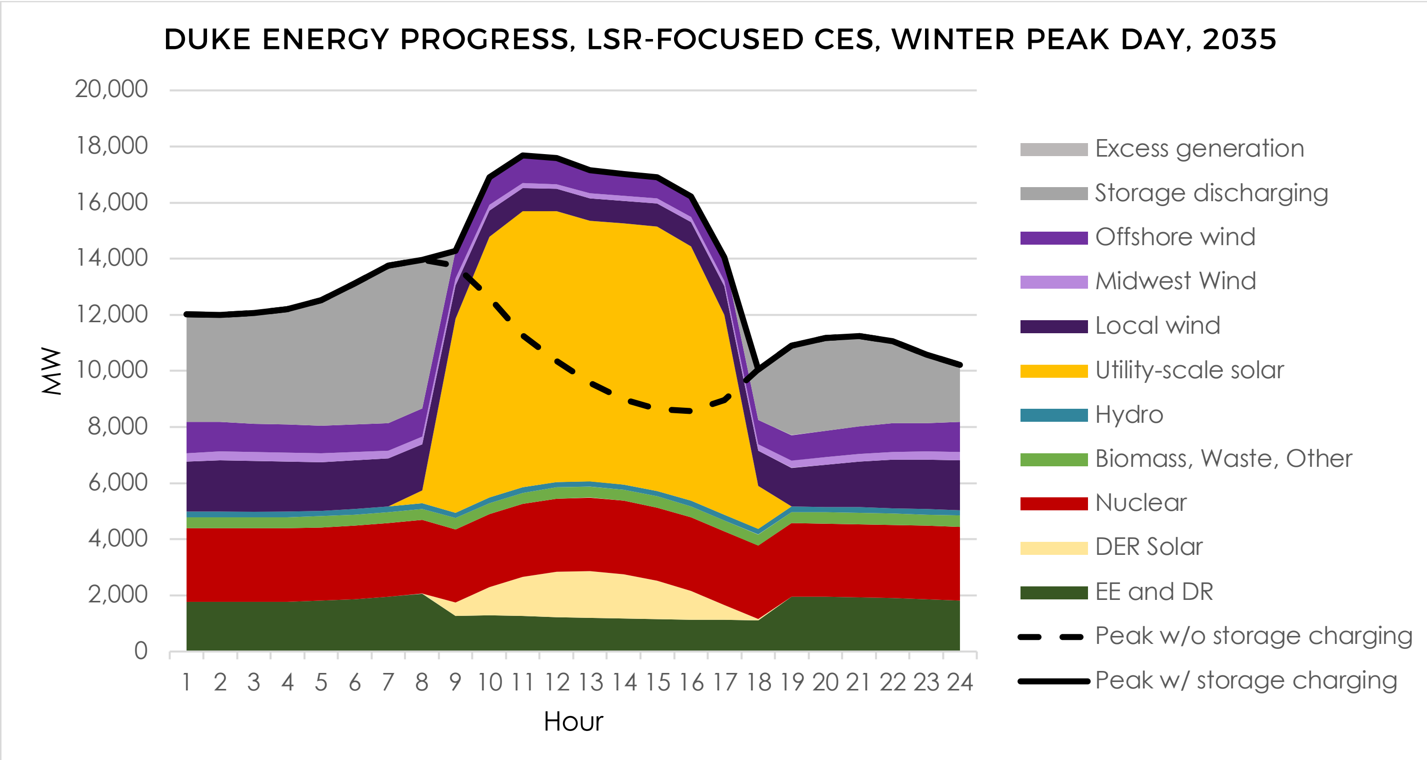
NextEra


FPL & GULF, LSR-FOCUSED CES, WINTER PEAK DAY, 2035
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage discharging
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

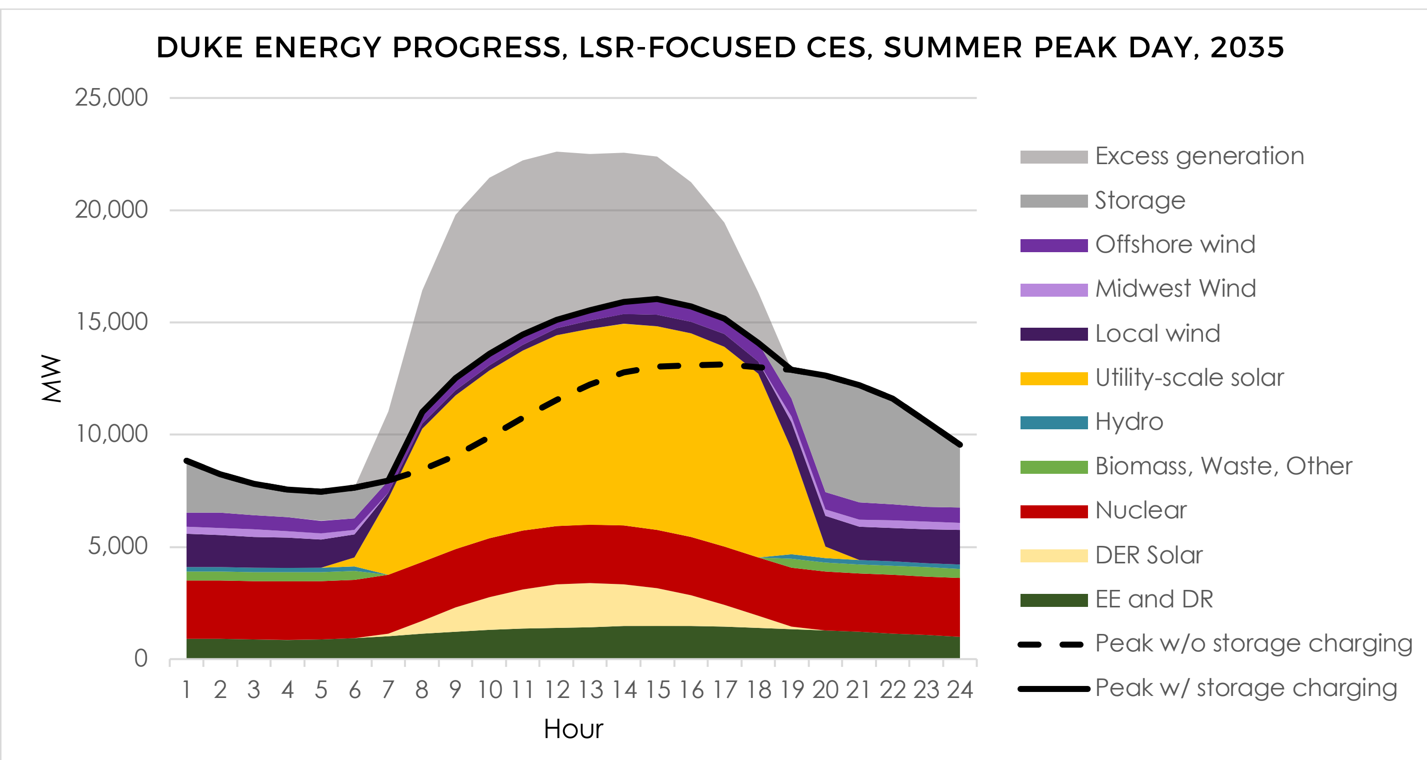

FPL & GULF, LSR-FOCUSED CES, SUMMER PEAK DAY, 2035
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging


FPL & GULF, LSR-FOCUSED CES, SPRING DAY, 2035
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

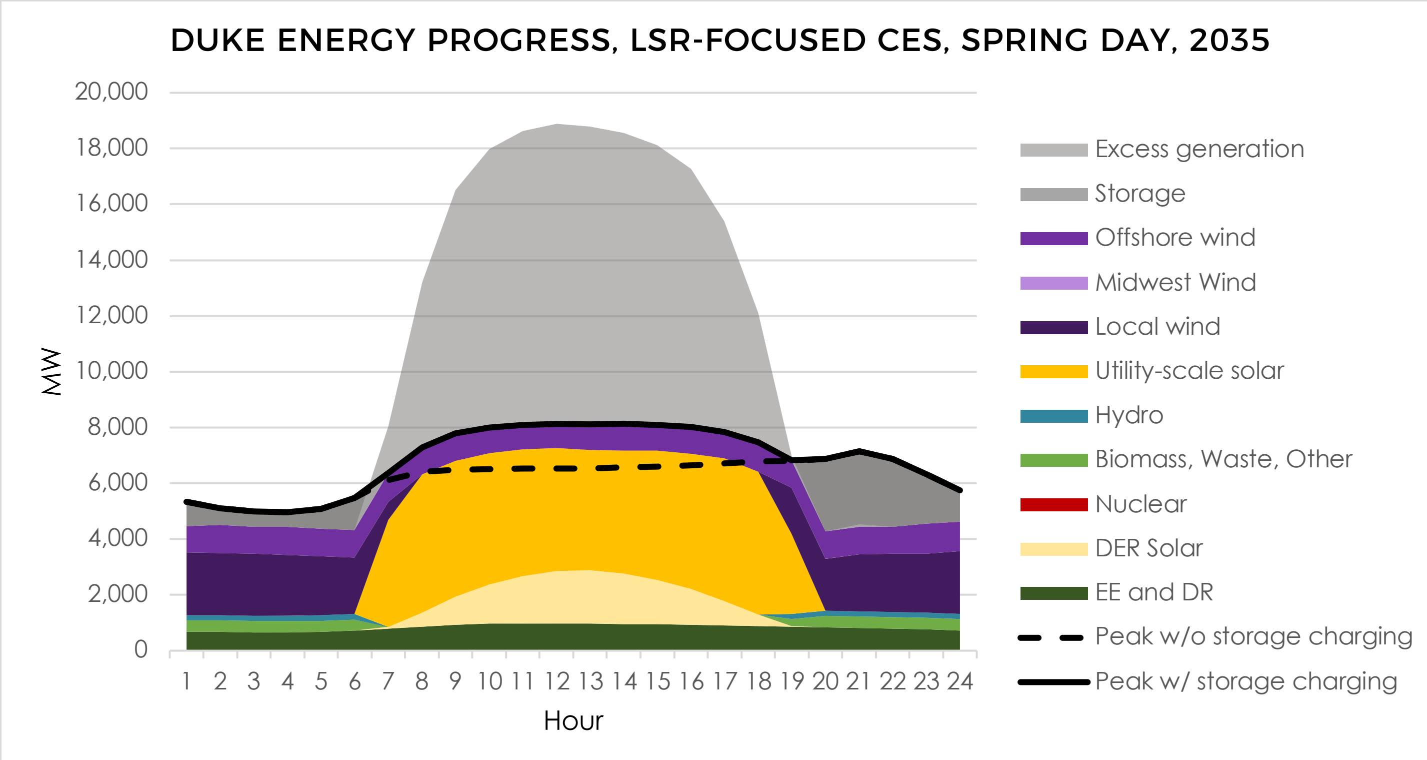
Duke Energy

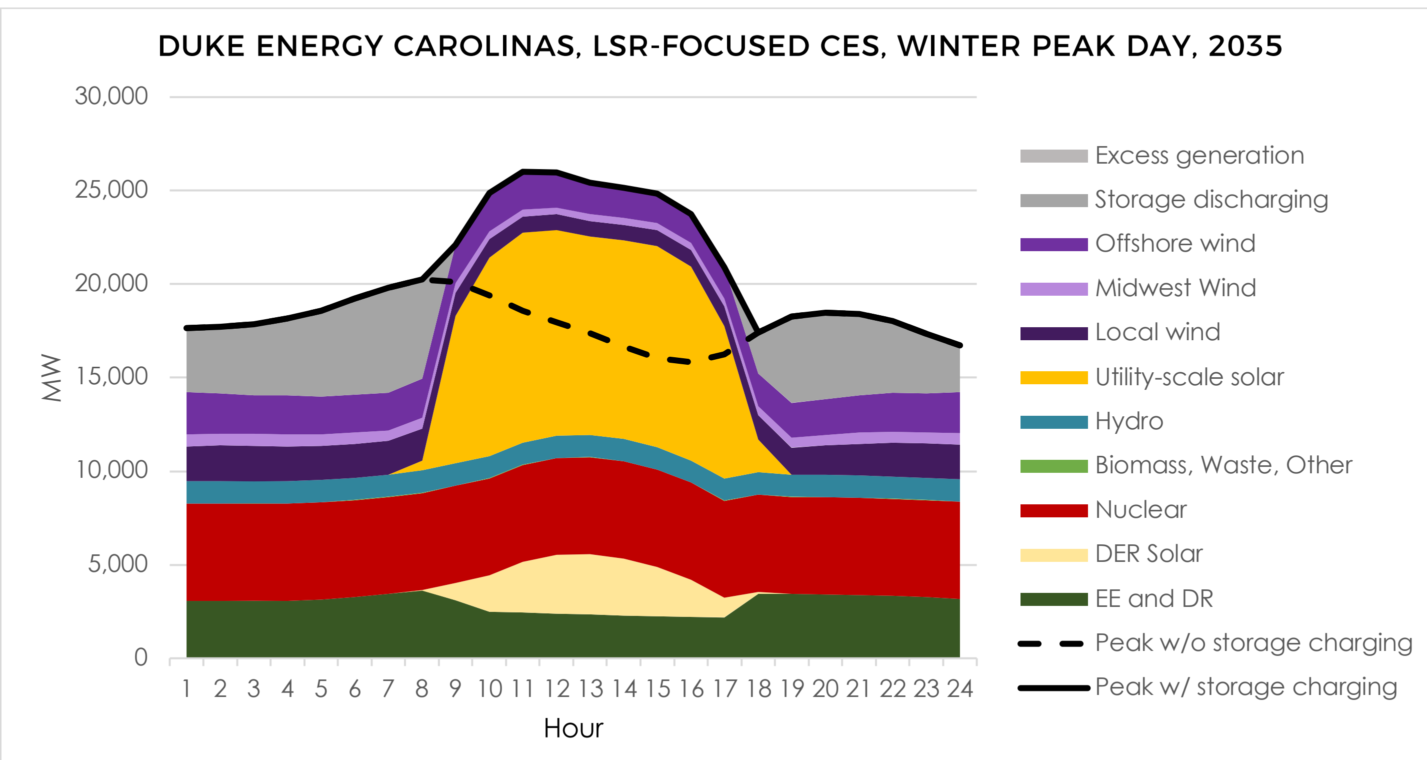


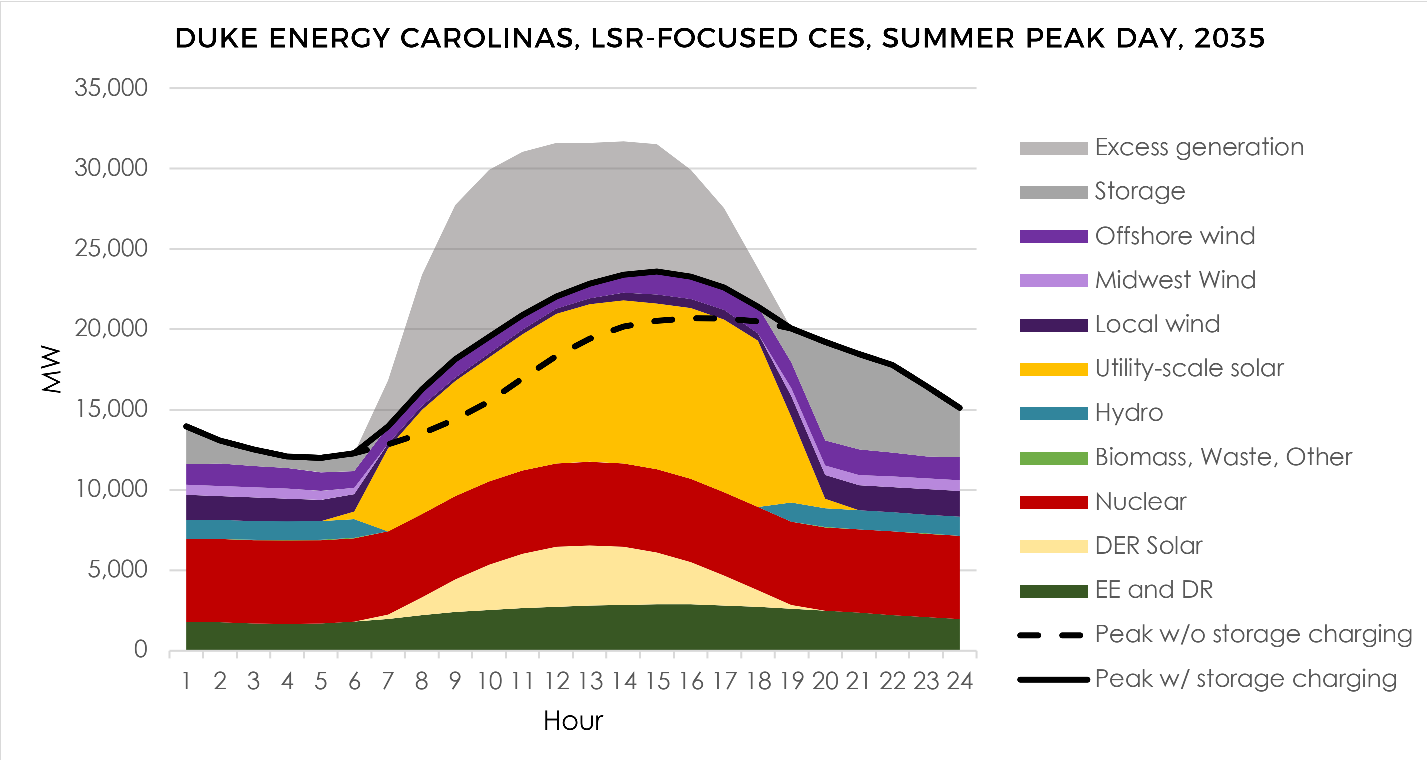
DUKE ENERGY PROGRESS, LSR-FOCUSED CES, WINTER PEAK DAY, 2035
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage discharging
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

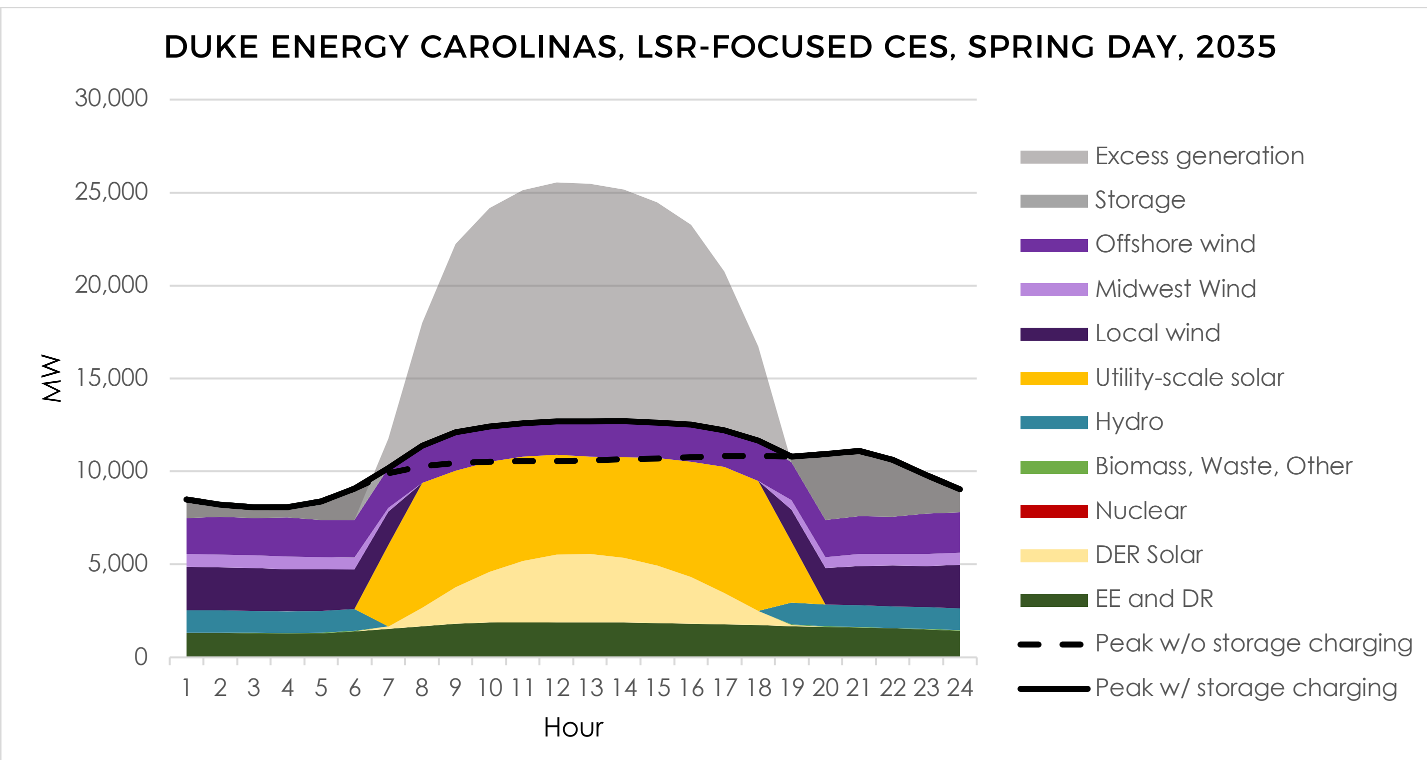


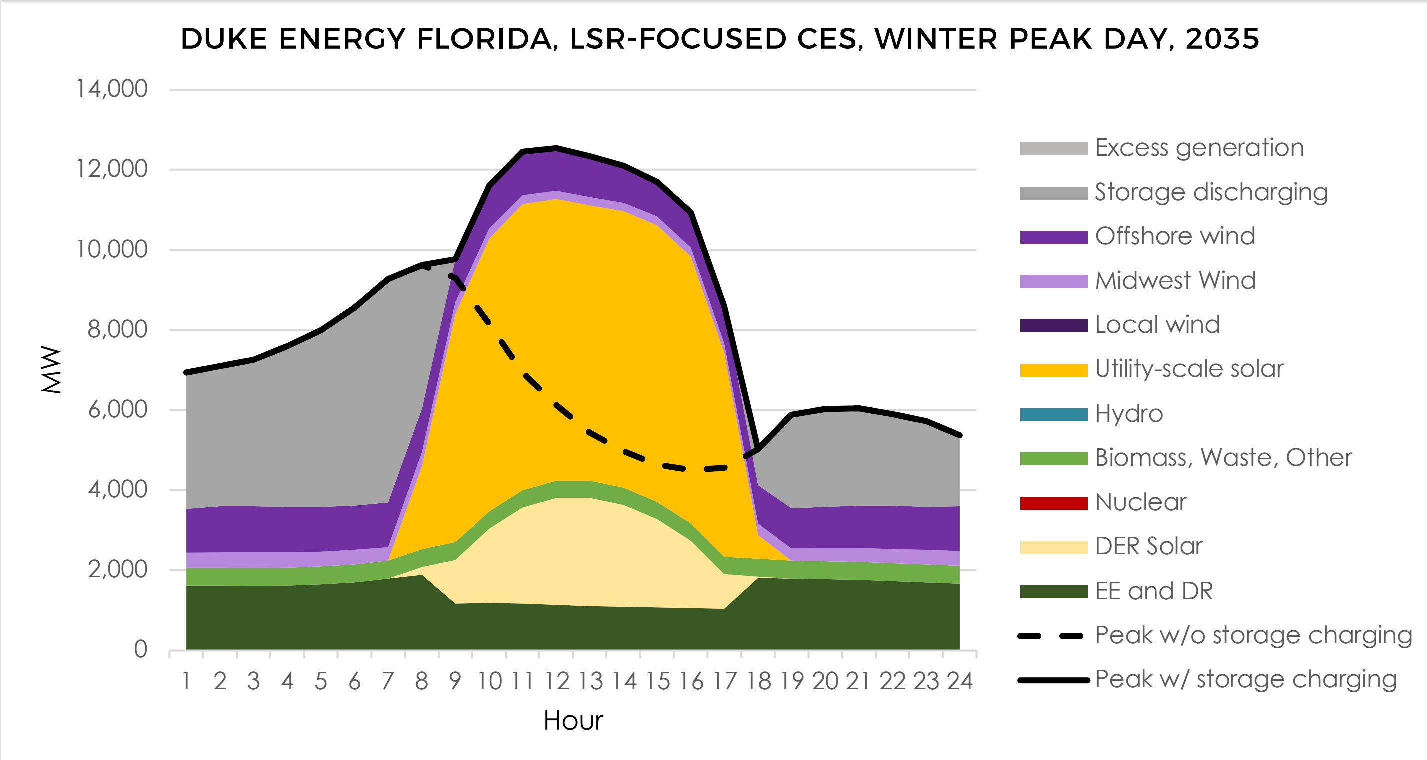
DUKE ENERGY PROGRESS, LSR-FOCUSED CES, SUMMER PEAK DAY, 2035
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

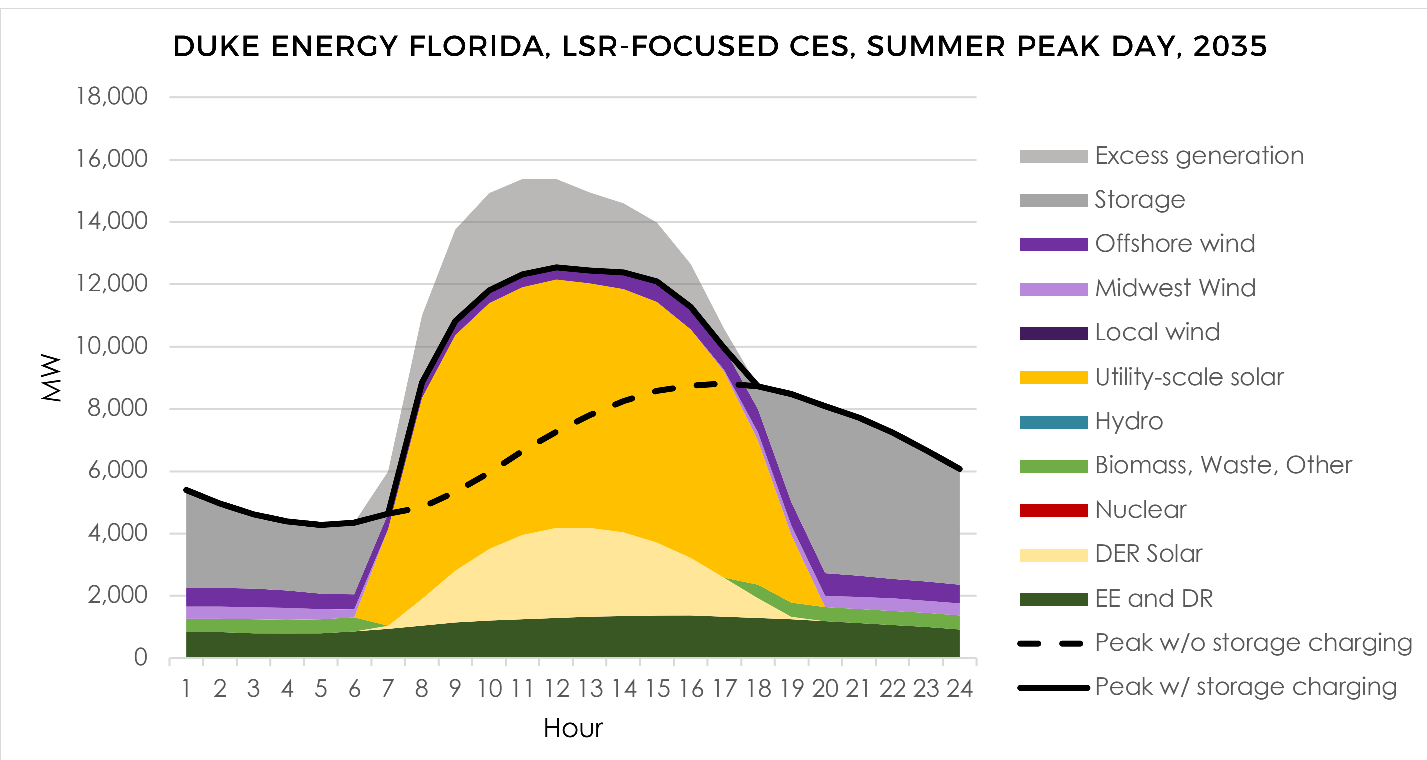

DUKE ENERGY PROGRESS, LSR-FOCUSED CES, SPRING DAY, 2035
MW
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

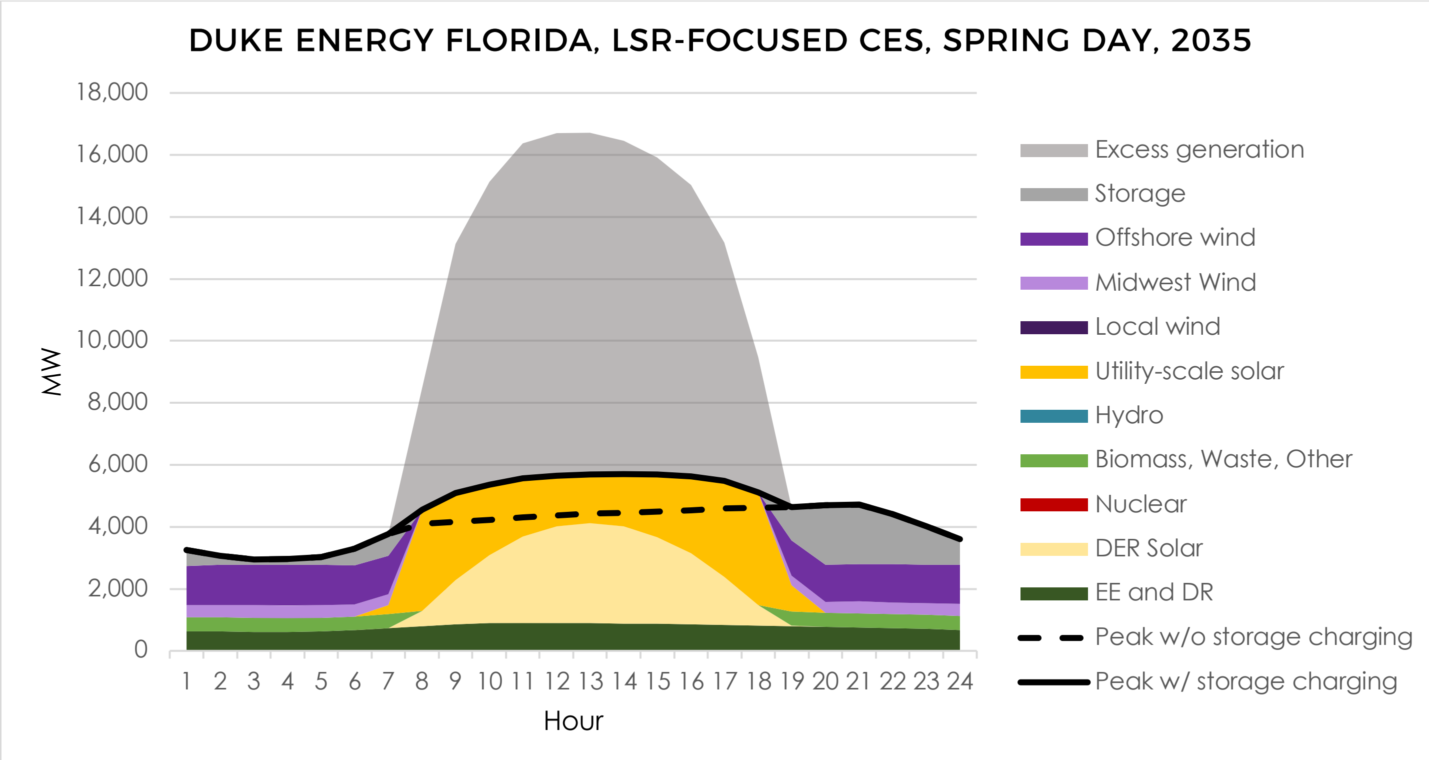

DUKE ENERGY CAROLINAS, LSR-FOCUSED CES, WINTER PEAK DAY, 2035
MW
30,000
25,000
20,000
15,000
10,000
5,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage discharging
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging


DUKE ENERGY CAROLINAS, LSR-FOCUSED CES, SUMMER PEAK DAY, 2035
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

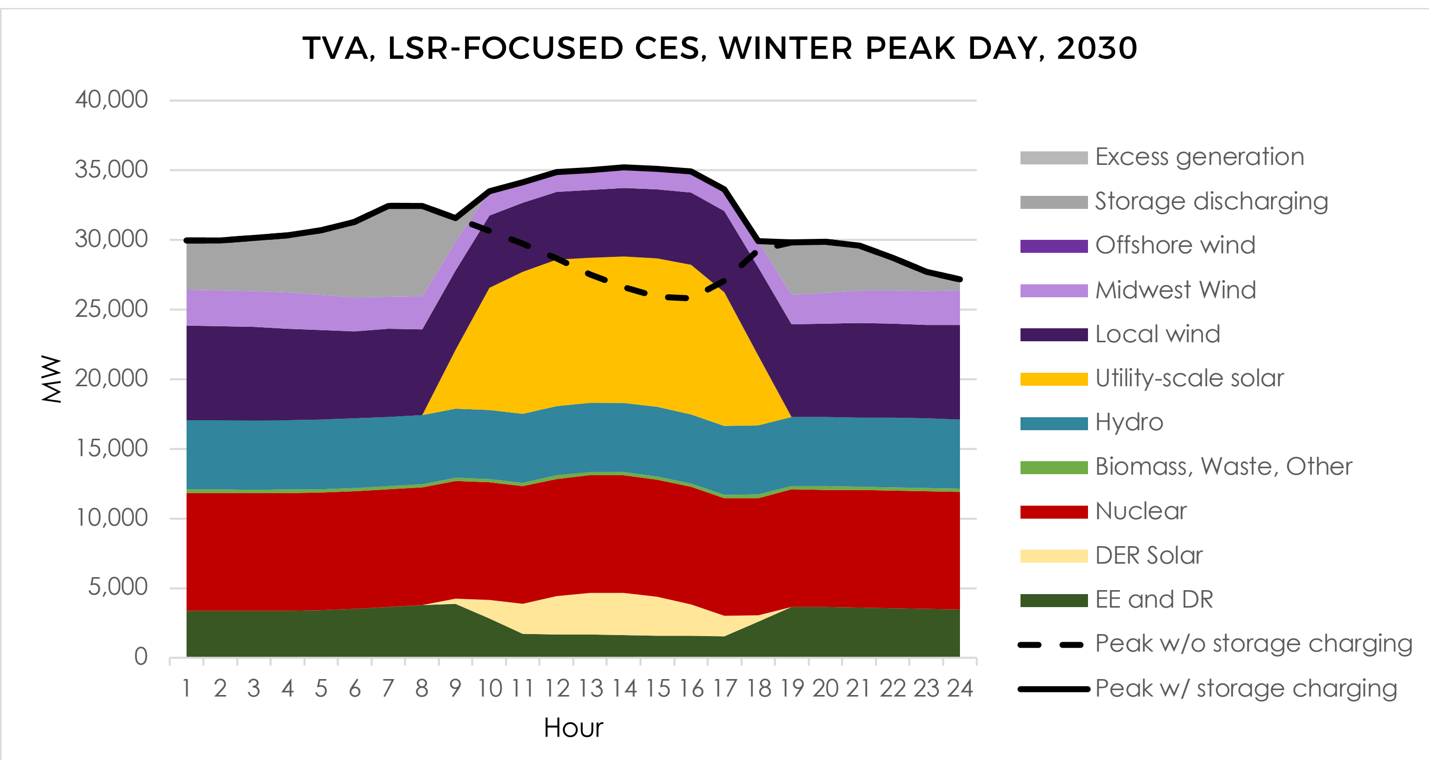

DUKE ENERGY CAROLINAS, LSR-FOCUSED CES, SPRING DAY, 2035
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

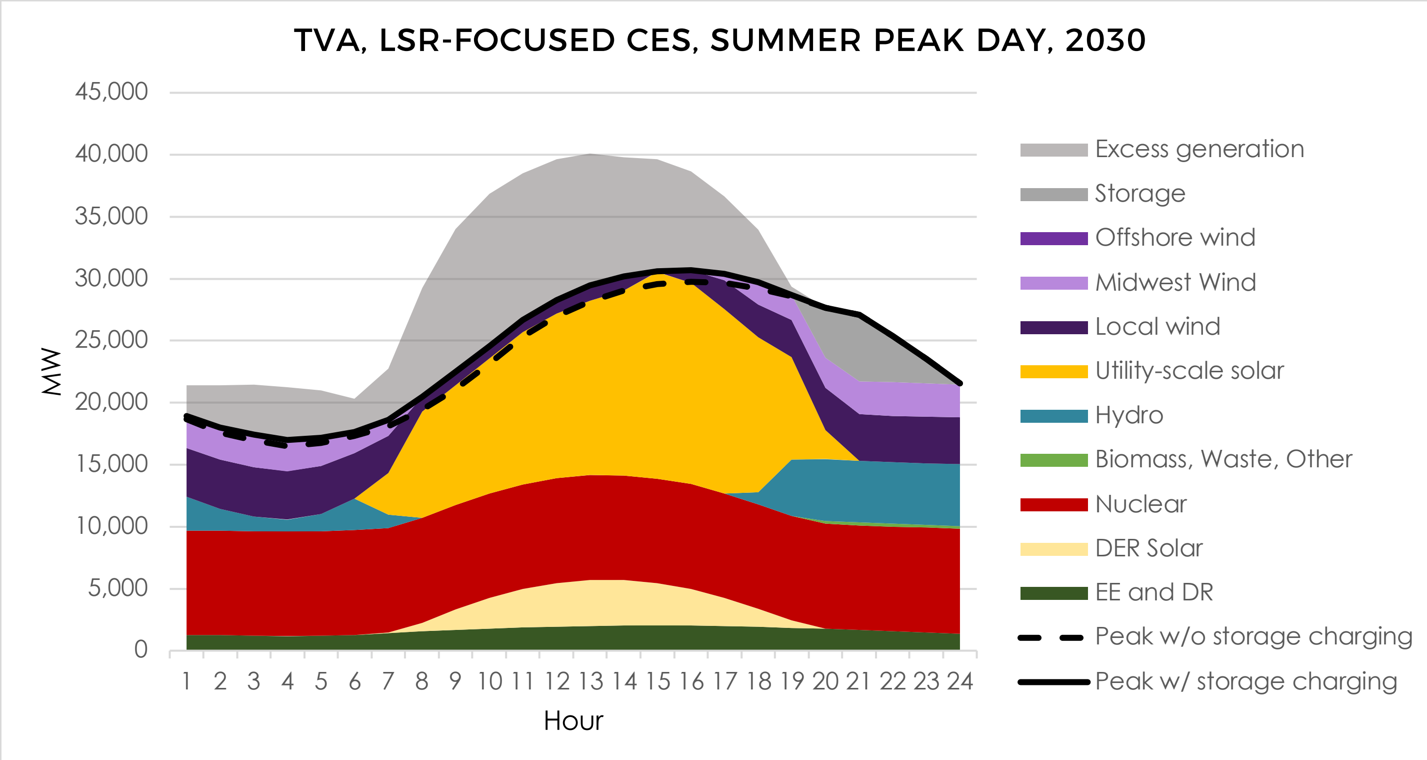

DUKE ENERGY FLORIDA, LSR-FOCUSED CES, WINTER PEAK DAY, 2035
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage discharging
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging


DUKE ENERGY FLORIDA, LSR-FOCUSED CES, SUMMER PEAK DAY, 2035
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging

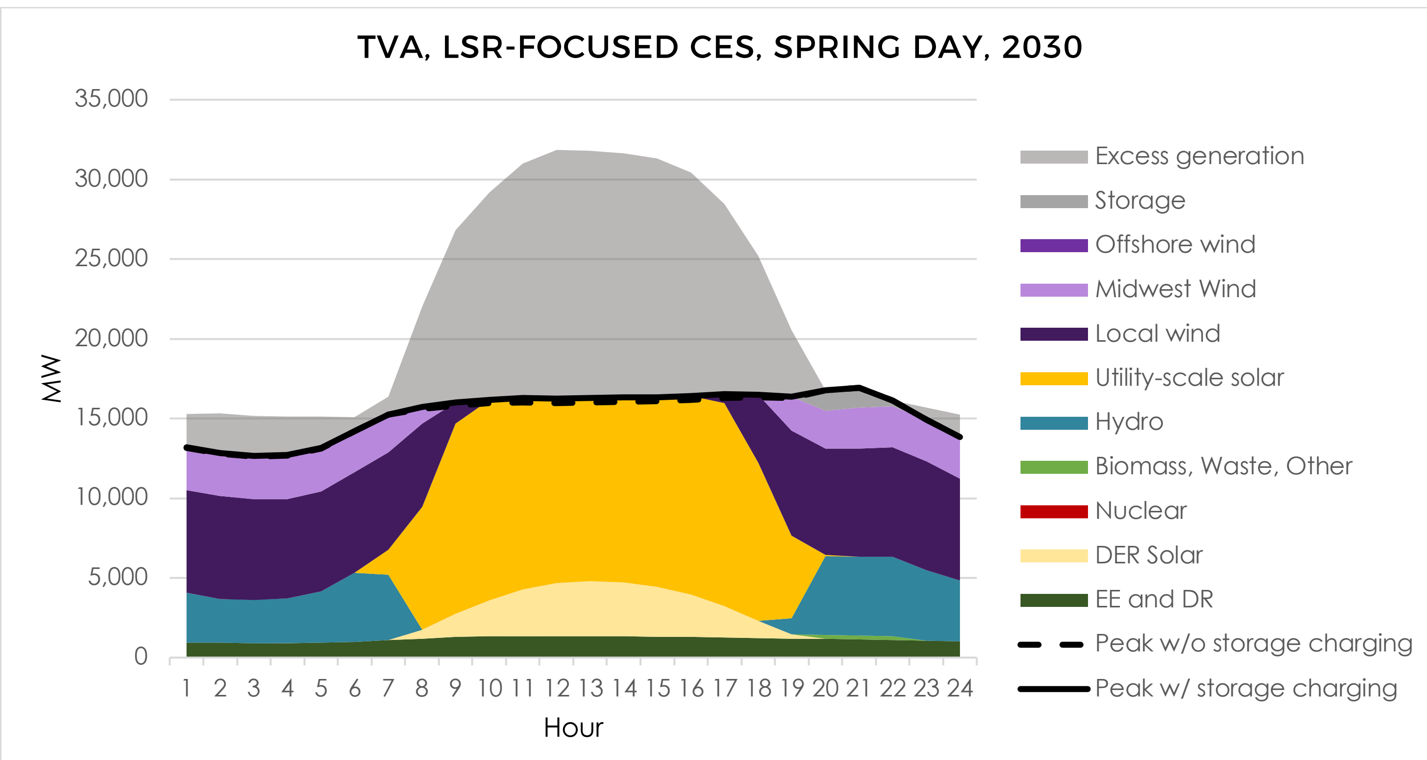


Tennessee Valley Authority





TVA, LSR-FOCUSED CES, SUMMER PEAK DAY, 2030
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging



TVA, LSR-FOCUSED CES, SPRING DAY, 2030
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Excess generation
Storage
Offshore wind
Midwest Wind
Local wind
Utility-scale solar
Hydro
Biomass, Waste, Other
Nuclear
DER Solar
EE and DR
Peak w/o storage charging
Peak w/ storage charging