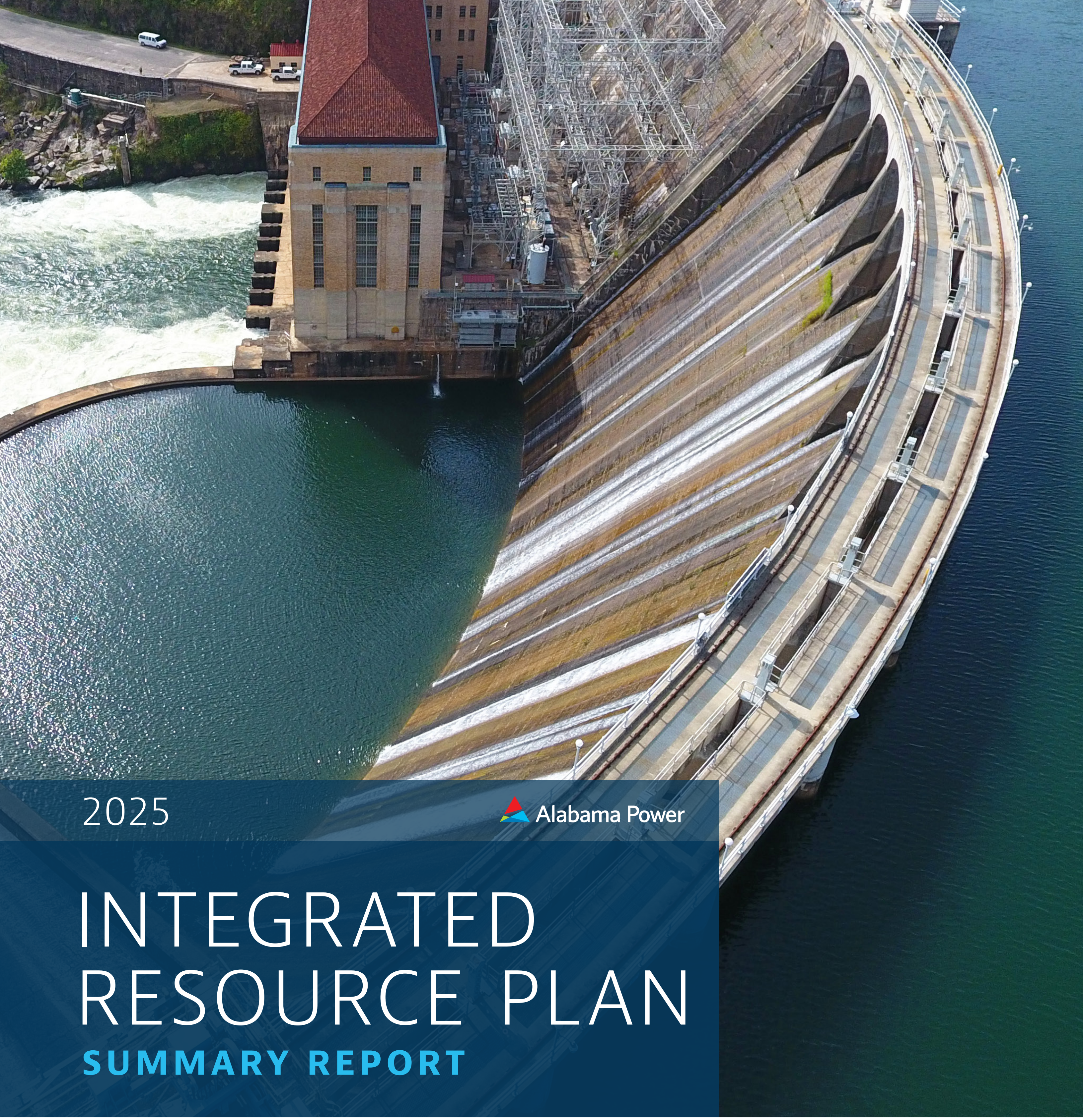
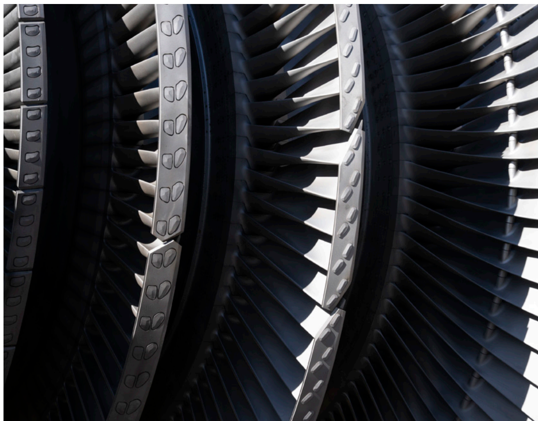


2025

Alabama Power

INTEGRATED RESOURCE PLAN

SUMMARY REPORT



2025

INTEGRATED RESOURCE PLAN

SUMMARY REPORT

Alabama Power

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EXECUTIVE SUMMARY

The 2025 Integrated Resource Plan Summary Report ("2025 IRP") provides an overview of the results of the most recently completed integrated resource planning process ("IRP process") for Alabama Power Company ("Alabama Power" or "Company"). Integrated resource planning is a comprehensive, data-intensive process that establishes the foundation for certain decisions affecting the Company's future portfolio of supply-side and demand-side resources. The IRP process itself does not determine what specific resources the Company must procure in the future. Rather, this management tool facilitates the Company's ability to make resource decisions through: (i) its development of an indicative list of future additions that meet appropriate reliability requirements in a cost-effective manner; and (ii) its accounting for risks and uncertainties inherent in planning for resources sufficient to meet forecasted customer demand. The IRP process also informs decision-making strategies involving the Company's existing portfolio of supply-side and demand-side resource options, better enabling the Company to adapt and respond to changes in external factors that could influence the Company's ability to provide reliable electric service to its customers.[1]

The IRP Summary Report is produced every three years and reviewed with the Alabama Public Service Commission ("APSC"). Through this review and other regulatory oversight, the APSC remains informed of the projected timing of resource additions and other planning assumptions, consistent with the Company's duty of service to customers and the need to provide the desired level of service reliability in a cost-effective manner. The APSC also receives detailed information regarding the IRP process through proceedings involving petitions by Alabama Power for a certificate of convenience and necessity related to specific resource additions.

Alabama Power remains committed to maintaining a diverse supply-side generating portfolio, along with cost-effective demand-side resources that benefit all customers. Resource diversity on the supply side – which includes nuclear, natural gas, coal, oil, hydroelectric, wind and solar resources – provides significant benefit to customers, as it helps mitigate risk and enables the Company to adapt to changes impacting its energy supply obligations. In that regard, the Company's generating fleet continues to transition in response to various factors, particularly the cost of compliance with environmental regulations issued by the U.S. Environmental Protection Agency ("EPA").

The Company's resource planning decisions are driven by the fact that Alabama Power has both summer and winter peak seasons. Accordingly, the Company employs separate summer and winter Target Reserve Margins ("TRM") to address reliability concerns over the course of a year. This seasonal planning approach provides greater visibility into the unique capacity needs associated with each period, rather than limiting reliability decisions to the requirements of a single season.

[1] Appendix 1 is a detailed list of all supply-side resources owned and controlled by Alabama Power. Appendix 2 summarizes the Company's activities related to existing and potential demand-side resources, including demand-side management programs.

Alabama Power's 2025 IRP reflects the results of the most recent Reserve Margin Study ("RMS") for the Southern Company System ("System").[2] The RMS provides a detailed reliability and economic analysis that yields appropriate seasonal TRMs for the System. For long-term planning starting in 2028 and beyond, the study supports a summer season System TRM of 20 percent and a winter season System TRM of 26 percent. Consistent with past practice, the RMS also evaluated System reliability needs on a shorter-term basis (2025-2027), which for planning purposes calls for a 19.50 percent System target and a 25.50 percent System target for those summer and winter seasons, respectively. Due to the benefits of load diversity, coordinated planning, and unit commitment and operations pursuant to the Southern Company System Intercompany Interchange Contract ("IIC" or "Southern Pool"), the Southern Company retail Operating Companies (i.e., Alabama Power, Georgia Power Company and Mississippi Power Company) can together achieve these System targets by each utilizing diversified reserve margins that are lower than the target reserve margins for the System as a whole. Thus, the diversified summer TRMs for Alabama Power are 19.09 percent over the long-term and 18.58 percent over the short-term. Likewise, Alabama Power's diversified winter TRMs are 25.13 percent over the long-term and 24.61 percent over the short-term. These diversified values are subject to revision in response to changes in System load. Figure ES-1 compares the prior seasonal TRMs to those predicated on the new RMS.

FIGURE ES-1: SUMMER AND WINTER TRM COMPARISON

Target Reserve Margins	2022 IRP	2025 IRP
System Long-Term Planning TRM (Summer)	16.25%	20.00%
System Short-Term Planning TRM (Summer)	15.75%	19.50%
Diversified Long-Term Planning TRM (Summer)	15.28%	19.09%
Diversified Short-Term Planning TRM (Summer)	14.78%	18.58%
System Long-Term Planning TRM (Winter)	26.00%	26.00%
System Short-Term Planning TRM (Winter)	25.50%	25.50%
Diversified Long-Term Planning TRM (Winter)	25.18%	25.13%
Diversified Short-Term Planning TRM (Winter)	24.69%	24.61%

Considering these TRMs and forecasted increases in load, Alabama Power projects a capacity deficit beginning in 2029. The Company will be assessing its options for most effectively addressing this anticipated capacity need in a timely manner.

[2]Except where otherwise noted, the Southern Company System includes Alabama Power Company, Georgia Power Company, Mississippi Power Company, and Southern Power Company resources included in the Southern Company System Intercompany Interchange Contract.

I. INTRODUCTION AND OVERVIEW

Alabama Power is an investor-owned electric utility, organized and existing under the laws of the State of Alabama, and is a subsidiary of Southern Company. In addition to Alabama Power, Southern Company is the parent of Georgia Power Company, Mississippi Power Company, and Southern Power Company (collectively with Alabama Power, the "Operating Companies"), Southern Company Gas, certain service companies and other subsidiaries. Alabama Power is primarily engaged in generating, transmitting and distributing electricity to the public in a large section of Alabama. The Company's retail rates and services are regulated by the APSC under the provisions of Title 37 of the Code of Alabama.

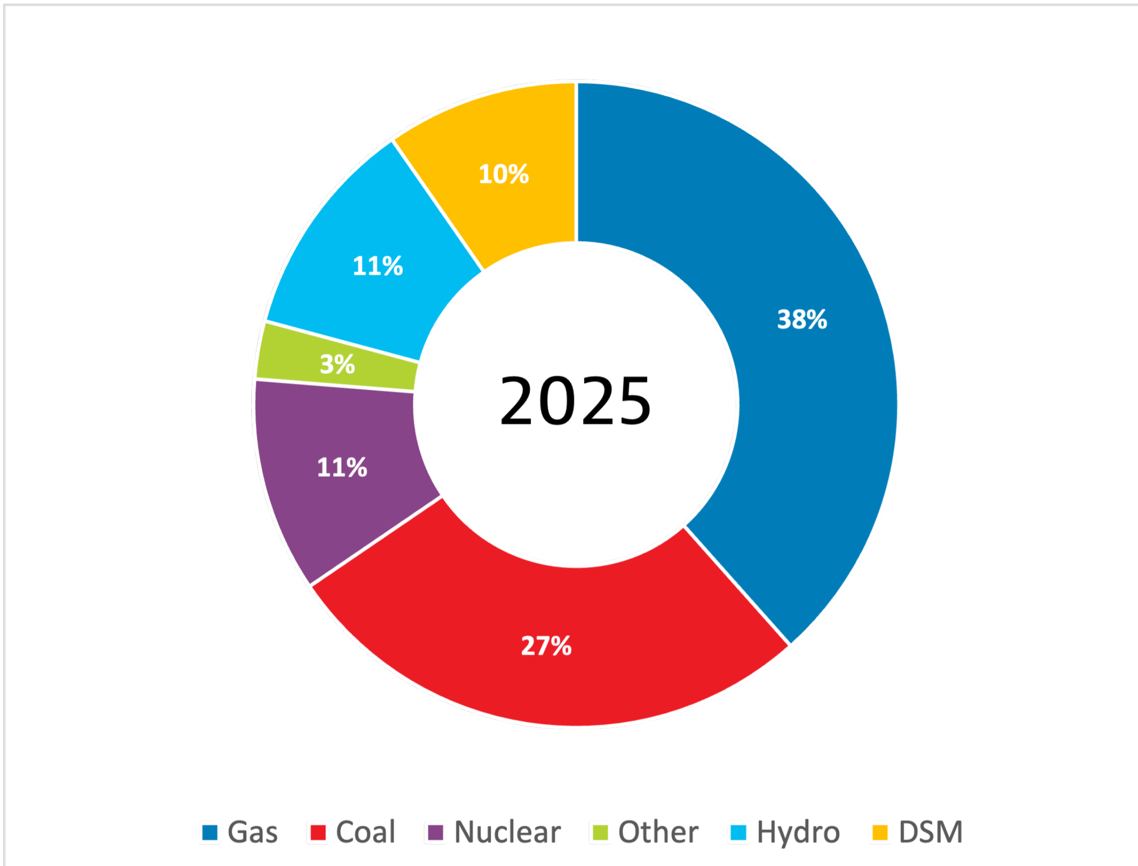
The Company has more than 1.5 million customers, of which approximately 86 percent are residential, 13.5 percent are commercial, and 0.5 percent are industrial and other. Alabama Power has more than 1.5 million transmission and distribution poles, and approximately 86,000 miles of power lines. The Company strives to maintain cost-effective and reliable service to its customers and continues to provide 99 percent service reliability. As noted earlier, Alabama Power has a diverse mix of supply-side (both owned and contracted) and demand-side resources, including hydroelectric, natural gas, nuclear, coal, oil, renewable[3], combined heat and power, and demand-side management ("DSM") programs.[4]

As of January 2025, Alabama Power had a combined resource capability of approximately 19,000 MW for the winter planning period and 18,000 MW for the summer planning period. The following figure reflects Alabama Power's diverse winter capacity mix comprising both owned and contracted resources.

[3]As applicable to all references to renewable projects in this 2025 IRP, the Company has rights to the environmental attributes, including the renewable energy certificates ("RECs"), associated with the energy from these projects. Alabama Power can choose to retire some, or all, of these environmental attributes on behalf of its retail electric customers, or it can sell the environmental attributes, either bundled with energy or separately, to third parties. Included in Appendix 1 is a listing of the Company's contracted or owned renewable projects.

[4]"Active" DSM programs (i.e., those under the control of the Company) are included in the IRP as supply resources, whereas the effects of "passive" DSM programs (i.e., those dependent on responsive customer behavior) are reflected in the Company's load forecast.

FIGURE I - 1: ALABAMA POWER WINTER CAPACITY MIX [5]



This document summarizes the results of Alabama Power's 2025 IRP and overviews the process used in its development. As noted at the outset, the IRP serves as the foundation for certain decisions affecting the Company's portfolio of resources, facilitating the Company's ability to provide reliable and cost-effective electric service to its customers. The IRP yields an indicative schedule of supply-side and demand-side resource additions to accomplish these objectives, consistent with the Company's duties and obligations to the public as a regulated public utility. The Company's IRP is performed through a coordinated process that includes the retail Operating Companies, with the assistance of their agent, Southern Company Services, Inc. ("SCS"). The process used by Alabama Power to develop the IRP comports with the provisions of the Public Utility Regulatory Policies Act of 1978, as amended, which contemplates the use of appropriate integrated resource planning by electric utilities.

[5] This figure does not include PowerSouth capacity resources made available to the Company for commitment and dispatch pursuant to the CPO Agreement (See Section II). Percentages reflect winter seasonal rating for dispatchable resources and nameplate ratings for variable energy resources and active DSM programs. "Other" category includes solar and wind resources.

As noted earlier, Alabama Power participates with the other Operating Companies in the Southern Pool, which provides for coordinated System operations and centralized unit commitment and joint dispatch of the Operating Companies' respective generating resources. The Southern Pool seeks to minimize total System production cost for the benefit of all participants, with after-the-fact accounting procedures assuring that each Operating Company realizes the economics of its lowest cost resources in accordance with the provisions of the IIC. To take advantage of economies of scale, the retail Operating Companies engage in the coordinated planning of their respective resource additions; however, each such Operating Company retains decision-making authority regarding any resource additions it may require, consistent with its respective duty of service as provided by law. Under the IIC, a retail Operating Company can, on a temporary basis, benefit from a short-term capacity surplus that might be present in the Southern Pool. However, each Operating Company is expected to have adequate resources, including an appropriate level of reserves, to reliably serve its own load obligations and cannot rely on the capacity of affiliates to meet the long-term needs of its customers.

The System is represented on the Southeastern Electric Reliability Council ("SERC"), which serves to coordinate operations and other measures to maintain a high level of reliability for the electric systems in the Southeastern United States. Likewise, Alabama Power and the other retail Operating Companies, along with nine other transmission owners, are sponsors of the Southeastern Regional Transmission Planning process, which provides an open, coordinated, and transparent transmission planning process for much of the Southeast in accordance with the requirements of FERC.

Consistent with its duty to serve, Alabama Power develops a load forecast that comprises a long-term projection of the expected energy and demand requirements of its customers. Using the best information reasonably available, the Company then develops an IRP that reflects an indicative optimized mix of supply-side and demand-side resources to meet the projected customer peak demand in a reliable and cost-effective manner. The resulting generic expansion plan provides suggestive guidance that helps inform decision-making, subject to the availability of more cost-effective opportunities or other overriding considerations.

Alabama Power's operations now reflect dual-season peaks, as historical summer peaking characteristics have given way to significant demands in the winter months. In recent years, Alabama Power's winter peak demand (both actual and weather-normalized) has exceeded its summer peak demand, and the Company's most recent load forecast continues to project a predominant winter peak demand. The Company's load forecast is discussed further in Section IV.C.

II. COORDINATED PLANNING AND OPERATIONS WITH POWERSOUTH

In 2021, Alabama Power and PowerSouth Energy Cooperative ("PowerSouth") entered into the Coordinated Planning and Operations ("CPO") Agreement. Under the CPO Agreement, which carries a minimum 10-year term, the two systems have combined their operations so that their respective generating resources can be jointly committed and dispatched. This optimization is intended to create energy cost savings and enhance system reliability for both parties. The CPO Agreement also contemplates mutually beneficial coordinated planning, but each company retains resource planning responsibility for its own system and PowerSouth must carry reserves commensurate with Alabama Power's diversified Target Reserve Margins.

III. ENVIRONMENTAL STATUTES AND REGULATIONS

III.A. GENERAL

The Company's operations are subject to extensive regulation by federal, state and local environmental agencies under a variety of statutes and regulations that impact air, water and land resources. Applicable statutes include: the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning and Community Right-to-Know Act; the Endangered Species Act; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; analogous state statutes; and related federal and state regulations. Compliance with these and other environmental requirements involves significant capital and operating costs. As of December 31, 2024, the Company has spent approximately $6 billion on environmental capital retrofit projects to comply with these requirements. The Company currently expects that capital expenditures to comply with environmental statutes and regulations will total approximately $579 million from 2025 through 2029. These amounts do not include any estimated compliance costs associated with the regulation of CO2 emissions from existing fossil fuel-fired electric generating units. Costs associated with closure in place and ground water monitoring of ash ponds in accordance with the Coal Combustion Residuals ("CCR") Rule are not reflected in the capital expenditures above, as these costs are associated with the Company's asset retirement obligation ("ARO") liabilities.

The Company's environmental compliance strategy, including potential unit retirement and replacement decisions and future environmental capital, operations expenditures, and costs reflected in ARO liabilities, is affected by many considerations, such as the final requirements of new or revised environmental regulations and the outcome of any associated legal challenges; the cost and performance of control technologies and options; the cost and availability of emissions allowances; and the Company's projected capacity and energy needs and fuel mix. To date, the Company's compliance strategy in response to federal environmental requirements has resulted in a reduction of more than 2,100 MW of coal-fired capacity, due to either fuel switching or the retirement of units. Compliance costs may result from, among other things, additional unit retirements, installation of new environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units.

Compliance with any new or revised federal or state legislation or regulations relating to air, water and land resources or other environmental programs could significantly affect many areas of the Company's operations. The full impact of any such changes cannot be known with certainty until the applicable legislation or regulation is finalized, legal challenges are resolved, and any necessary rules are implemented at the state level. In any case, such governmental mandates could result in significant additional capital expenditures and compliance costs that could drive future unit retirement and replacement decisions. Many of the Company's commercial and industrial customers could also be impacted by such future environmental requirements, which for some may have the potential to affect their demand for electricity.

III.B. AIR QUALITY

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Additional controls to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements may become necessary in the future, depending on further actions taken by Congress, the EPA, or by the ADEM. Certain notable programs are discussed below.

In 2012, the EPA finalized the Mercury and Air Toxics Standards ("MATS") Rule ("2012 MATS Rule"), which imposed stringent emissions limits for acid gases, mercury, and particulate matter on coal-fired and oil-fired electric utility steam generating units ("EGUs"). The compliance deadline set by the 2012 MATS Rule was April 16, 2015, with provisions for extensions to April 16, 2016. The compliance strategy for the rule included emission controls, retirements and fuel conversions.

On June 29, 2015, the Supreme Court ruled that the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant ("HAP") emissions from EGUs. The EPA issued a Supplemental Finding ("2016 Supplemental Finding") on April 15, 2016, in response to the Supreme Court's decision. The 2016 Supplemental Finding revised the EPA's consideration of costs, but it did not have any impact on the 2012 MATS Rule compliance requirements or deadlines.

On April 16, 2020, the EPA published a reconsideration ("2020 Supplemental Finding") of its assessment of costs in the 2016 MATS Supplemental Finding and concluded there were flaws in the approach to considering costs and benefits. In the 2020 Supplemental Finding, the EPA determined that a proper consideration of costs demonstrates that the total projected cost of compliance dwarfs the monetized HAP benefits of the rule. However, the EPA further concluded that the absence of such a finding does not affect the status of the 2012 MATS Rule, which remains in effect. The EPA also took final action on the required Residual Risk and Technology Review ("RTR") ("2020 MATS RTR") and determined that the residual risks from HAP emissions from these EGUs are acceptable and no new cost-effective HAP controls have been identified to achieve further emission reductions. Accordingly, the EPA determined that revisions to the 2012 MATS Rule were not warranted. On March 6, 2023, the EPA published a final determination revoking the 2020 Supplemental Finding and reinstating the 2016 Supplemental Finding, which had concluded it was "appropriate and necessary" to regulate HAPs from EGUs after considering costs.

On May 7, 2024, the EPA finalized amendments to the rule ("2024 MATS RTR") resulting from its review of the 2020 MATS RTR. The amendments lowered the particulate matter ("PM") surrogate emission standard for non-mercury HAP metals and required the installation of PM continuous emission monitoring systems ("CEMS"). Compliance with the rule is required by July 2027. The rule impacts Alabama Power's obligations for monitoring PM emissions, but the Company expects to rely on its existing emission controls to comply with the more stringent emission standard. On March 31, 2025, Southern Company submitted a presidential exemption request for units subject to the 2024 MATS RTR that included Barry Unit 5 and Miller Units 1–4. On April 8, 2025, under the Presidential Proclamation entitled Regulatory Relief for Certain Stationary Sources to Promote American Energy, the request was granted and the compliance deadline for these units was extended to July 2029. The units will remain subject to the existing compliance obligations prior to issuance of the final rule.

On June 11, 2025, the EPA published a proposed rule to repeal specific requirements of the 2024 MATS RTR and found that the revisions to the rule were not necessary because they impose large compliance costs or raise potential technical feasibility concerns. The EPA proposes to repeal the revised PM surrogate emission standard and the requirement to install PM CEMS.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard ("NAAQS"). On October 1, 2015, the EPA finalized a rule that lowered the current eight-hour standard. As part of its five-year NAAQS review cycle of the ozone standards, the EPA decided in a final rulemaking on December 23, 2020, to retain without revision the 2015 ozone NAAQS (with which all areas within the Alabama Power service territory are in attainment). However, on August 21, 2023, the EPA announced its intent to initiate a new ozone NAAQS review that could result in a further tightening of the ozone standard.

The EPA regulates fine PM concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the current PM NAAQS. On December 18, 2020, as part of the required review cycle of the PM NAAQS, the EPA determined to retain all existing NAAQS for particulate matter. However, on June 10, 2021, the EPA announced its decision to reconsider the standards and stated that the scientific evidence supports lowering the annual standard from the current level. On March 6, 2024, the EPA published its reconsideration of the 2020 PM NAAQS, which lowered the primary annual PM2.5 standard. The State of Alabama submitted a recommendation to the EPA on February 7, 2025 to designate all areas in attainment with the lower PM2.5 standard. On March 12, 2025, the EPA announced plans to reconsider the PM NAAQS final rule.

The EPA also has prescribed NAAQS for sulfur dioxide ("SO2"). Final revisions to the 1-hour SO2 NAAQS became effective in 2010. In January 2017, the Company submitted modeling showing attainment of the SO2 standard in the vicinity of its coal-fired generating plants. On December 21, 2020, the EPA finalized Round 4 designations for the SO2 NAAQS, which included the designation of a portion of Shelby County as "attainment/unclassifiable." This EPA action concluded designations for Alabama regarding the 2010 1-hour SO2 NAAQS, with no area in the state being designated as nonattainment.

In 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR") to address impacts in downwind states of SO2 and NOX emissions from fossil fuel-fired electric generating plants. CSAPR established emissions trading programs and budgets for certain states and allocates emissions allowances for sources in affected states, including Alabama. In 2016, the EPA published a final rule ("CSAPR Update Rule") establishing more stringent ozone season NOX emissions budgets for several states (including Alabama) to ensure compliance with the 2008 ozone NAAQS.

Since the CSAPR Update Rule did not address the more stringent 2015 ozone NAAQS, the ADEM submitted a State Implementation Plan ("SIP") containing interstate transport obligations addressing the 2015 ozone NAAQS. On February 13, 2023, the EPA published its disapproval of twenty-one interstate transport SIP submissions, which included Alabama. This disapproval allowed the EPA to finalize a Federal Implementation Plan ("FIP") (known as the "Good Neighbor Plan") for these states, which was published on June 5, 2023. The Good Neighbor Plan requires additional ozone season NOx emission reductions that significantly reduce Alabama's ozone season NOX allowance budget. The ADEM, the State of Alabama and Alabama Power subsequently filed petitions in the Eleventh Circuit for review of the EPA's final action disapproving Alabama's interstate transport SIP and on June 13, 2023, filed a joint motion for a stay. On August 17, 2023, the Eleventh Circuit granted the stay; therefore, the Good Neighbor Plan for Alabama is currently not in effect for Alabama Power. On August 4, 2023, the ADEM, the State of Alabama, and Alabama Power also filed petitions for review of the EPA's FIP in the

Eleventh Circuit. Oral argument regarding the EPA's SIP disapproval was held on September 24, 2024, but the Eleventh Circuit later held the case in abeyance pending the Supreme Court's resolution of cases to address the venue provision. On June 18, 2025, the Supreme Court issued a ruling stating that SIP disapprovals are locally and regionally applicable actions and can therefore be heard in regional Courts instead of the D.C. Circuit. Litigation regarding the SIP and FIP remains pending.

In addition to the above-described Eleventh Circuit litigation, several petitions for review and stay motions were filed in the D.C. Circuit challenging the EPA's Good Neighbor Plan, and on September 25, 2023, the Court denied the stay motions. Petitioners filed emergency stay requests to the Supreme Court and on June 27, 2024, the Supreme Court issued a stay of the Good Neighbor Plan. On March 10, 2025, the EPA filed a motion for voluntary remand of the Good Neighbor Plan to reconsider the final rule and review which states are subject to it. The EPA anticipates completing a new rulemaking in 2026. The litigation in the D.C. Circuit is being held in abeyance and the Supreme Court stay will remain in place while the EPA completes the reconsideration process.

The EPA finalized regional haze regulations in 2005 and 2017. These regulations require states, tribal governments, and various federal agencies to develop and implement plans to reduce pollutants that impair visibility and demonstrate reasonable progress toward the goal of restoring natural visibility conditions in certain scenic areas (Class I areas, including national parks and wilderness areas) across the United States by 2064. Regional haze regulations established specified planning periods where states must meet reasonable progress toward visibility milestones at each Class I area. These planning period reviews could require further reductions in certain pollutants such as PM, SO2 and NOX, which may result in increased compliance costs to the Company. States must submit SIPs that evaluate whether further controls for visibility impairing these pollutants are necessary. SIP revisions for the second planning period (2018-2028) were required by July 31, 2021. On August 30, 2022, the EPA published a finding that fifteen states (including Alabama) failed to submit SIPs by the required deadline. Alabama is currently in the process of developing SIP revisions for the second planning period. However, on March 12, 2025, the EPA announced plans to reconsider its implementation of the Regional Haze Program.

On March 8, 2022, the EPA finalized amendments to the National Emission Standards for Hazardous Air Pollutants for stationary combustion turbines. The final action removed the stay of the standards for new premix and diffusion flame gas-fired turbines, affecting turbines at major sources of HAPs that began construction after January 14, 2003. Affected units must meet formaldehyde limits and continuously monitor and maintain minimum flue gas temperatures. There are also restrictions for startup, shutdown and malfunctions for affected turbines. The requirements pertain only to new combustion turbines, such as Plant Barry Unit 8, and not to existing units.

III.C. WATER QUALITY

Compliance with the Clean Water Act ("CWA") and associated regulations has also been and will continue to be a significant focus for the Company. While there are various regulatory activities arising in the context of the CWA, such as cooling water intake requirements under section 316(b) and litigation involving the definition of Waters of the United States, effluent limitation guidelines ("ELG") have been the most impactful compliance area for Alabama Power with regards to water compliance in recent years. Established by the EPA over 50 years ago, ELG regulates discharge of wastewater from steam electric generating facilities. On November 3, 2015, the EPA published its first major revision to the steam electric ELG in over 30 years. That ELG rule ("2015 ELG Rule") imposed more stringent technology-based requirements on wastewater discharges from coal-fired plants, including fly ash transport water ("FATW"), bottom ash transport water ("BATW") and flue gas desulfurization ("FGD" or "scrubber") wastewater.

In September 2017, the EPA released a final rule postponing by two years the 2015 ELG Rule's earliest possible compliance date for the FGD wastewater and BATW streams while the agency reconsidered the 2015 rulemaking. The EPA subsequently published its final ELG Reconsideration Rule ("2020 ELG Rule") in the Federal Register on October 13, 2020, with an effective date of December 14, 2020.

The 2020 ELG Rule differed from the 2015 ELG Rule in several important respects. First, it established changes to certain discharge limitations applicable to FGD wastewater and BATW, including more stringent limitations for certain constituents. In addition, it altered certain mandatory compliance timelines, including extending the latest "as soon as possible" date from December 31, 2023 to December 31, 2025. Further, the 2020 ELG Rule provided alternate compliance options, in lieu of complying with the generally applicable limitations, and established a process allowing regulated entities to transfer among the various compliance options, subject to specified requirements. Any facility wanting to comply with the permit conditions and discharge limitations associated with any of the alternate compliance options included in the 2020 ELG Rule was required to submit a Notice of Planned Participation ("NOPP") to its permitting authority by October 13, 2021.

Alabama Power complied with the 2015 and 2020 ELG Rules in various ways. For Plant Miller, Alabama Power deployed compliance solutions to manage effluent limitations consistent with the applicable requirements. Plant Barry Unit 4 has converted to natural gas and Barry Unit 5 will cease coal combustion by no later than December 31, 2028. For Plant Gaston Units 1-4, the 2025 IRP reflects the assumption of compliance with ELG with continued backup operation on coal through 2034. Plant Gaston Unit 5 is expected to repower to operate solely on natural gas by the end of 2028.

For the third time in less than 10 years, the EPA revised the ELG limitations with a supplemental rulemaking published on May 8, 2024 and effective July 8, 2024 ("2024 ELG Rule"). The 2024 ELG Rule differed from both the 2015 and 2020 ELG Rules in several important areas. Key changes include: (1) setting zero liquid discharge ("ZLD") BAT effluent limitations for FGD wastewater and BATW with an "as soon as possible" but no later than December 31, 2029 compliance date; and (2) setting new BAT limitations for combustion residual leachate ("CRL"), unmanaged CRL, and legacy wastewater. The new limitations require ZLD for CRL, as well as more stringent limits for legacy wastewater and unmanaged CRL. The 2024 ELG Rule maintained the 2028 permanent cessation of coal combustion subcategory from the 2020 ELG Rule as well as most of the transfer provisions applicable to the Company. The 2024 ELG Rule also created a new permanently ceasing coal combustion subcategory for units complying with certain BAT compliance options from the 2020 ELG Rule that will retire or repower by December 31, 2034. To select this compliance subcategory, a NOPP must be filed with the regulatory agency by December 31, 2025. Alabama Power continues to review the 2024 ELG Rule regarding compliance options for Plants Gaston, Barry and Miller. On March 12, 2025, the EPA announced that it would once again revise this Rule. On June 30, 2025, the EPA announced its intent to advance this action by proposing to extend compliance deadlines for many of the zero-discharge requirements in the 2024 ELG Rule and the deadline for facilities to decide whether to submit a NOPP. The EPA also intends to explore other flexibilities to promote reliable and affordable power generation.

This initial rulemaking is expected to seek additional information on zero-discharge technologies, including cost and performance data. The resulting information will help the EPA determine whether to move forward with a second rulemaking to address zero-discharge technologies and other flexibilities to ensure that electric utilities can better meet projected energy demand over the next decade. The scope of this second rulemaking could also address unmanaged combustion residual leachate, another type of wastewater.

III.D. COAL COMBUSTION RESIDUALS

In 2015, the EPA finalized the CCR Rule, which established non-hazardous solid waste regulations for the management and disposal of CCR (including coal ash and gypsum) in landfills and surface impoundments (ash ponds) at active generating power plants. Among other things, the CCR Rule requires CCR facilities to be evaluated against a set of performance criteria. The ADEM has also finalized regulations regarding the handling of CCR. In April 2019, Alabama Power initiated closure of its unlined CCR impoundments and ash ponds in accordance with these regulations. At this time, the Company does not expect the closure process to impact the availability or operation of its supply-side resources.

III.E. CLIMATE ISSUES

The EPA has made three attempts to promulgate rules aimed at regulating CO2 emissions from existing fossil fuel-fired electric generating units. First, in October 2015, the EPA finalized the Clean Power Plan ("CPP"), which aimed to shift generation from fossil fuels to renewables through a cap-and-trade program. However, the Supreme Court stayed the CPP in February 2016, preventing it from taking effect. Second, in June 2019, the EPA repealed the CPP and replaced it with the Affordable Clean Energy ("ACE") rule, which focused on efficiency improvements at individual generating units. The CPP was repealed because the EPA determined it had exceeded its statutory authority under the CAA by relying on standards and methods that could not be implemented by individual facilities. Both the CPP repeal and the ACE rule were challenged on appeal, and in January 2021, the D.C. Circuit vacated the ACE rule and remanded it to the EPA. On May 9, 2024, for the third time, the EPA finalized a new set of rules in response to this action ("111 GHG Rules"). The 111 GHG Rules require new combustion turbine units to install carbon capture and sequestration ("CCS") or comply with a CO2 emission standard based on utilization. The 111 GHG Rules also instruct states to develop plans that will include requirements for existing coal-fired units to install CCS, co-fire natural gas, or set early retirement dates. Moreover, existing gas-fired or oil-fired steam electric generating units would be required to meet a CO2 emission standard based on utilization. Compliance is required as early as January 1, 2030 or by January 1, 2032, based on the type of unit and compliance option. However, on June 11, 2025, the EPA announced further action regarding GHG emissions from fossil fuel-fired power plants, proposing to repeal the 111 GHG Rules. This latest proposal offers two pathways: one that would fully repeal all existing GHG emission standards for new and existing coal and gas plants, and an alternative that would repeal the requirement to install CCS and all other requirements for existing coal, gas, and oil-fired units. The EPA is seeking to finalize its decision by December 2025. The impact and outcome of this proposed rule cannot be determined at this time.

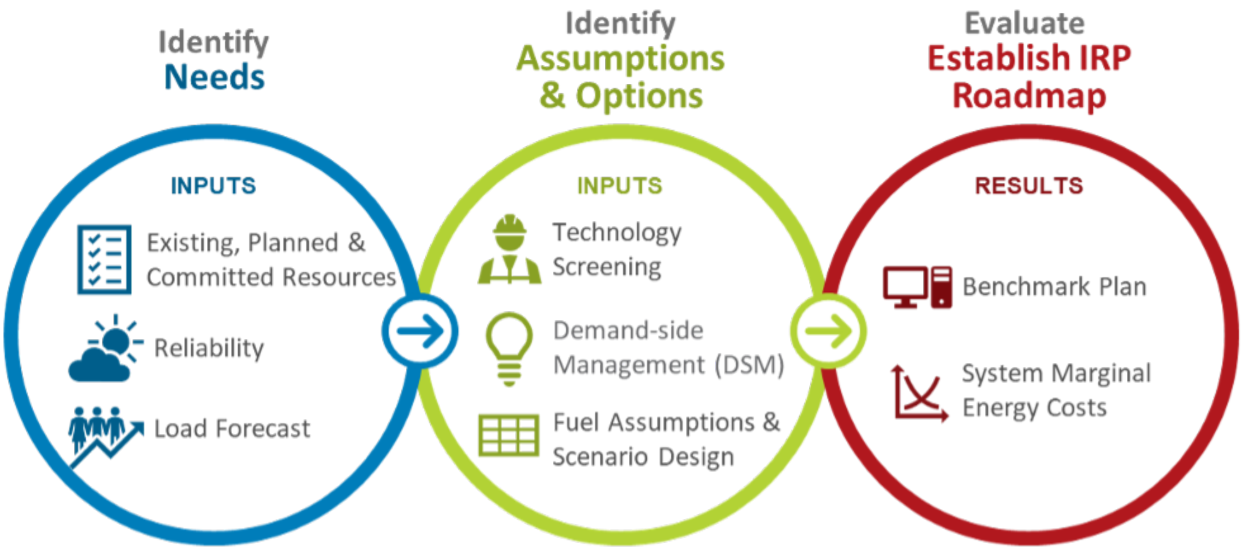
IV. INTEGRATED RESOURCE PLAN

IV.A. IRP PROCESS OVERVIEW

The IRP process is designed to identify the timing, amount and types of indicative resources needed to serve the long-term energy and demand requirements of Alabama Power's customers. The IRP process includes several sequential steps, ultimately leading to the identification of future resource needs, the development of generic expansion plans and the production of marginal energy cost forecasts that inform a variety of planning decisions. Aided by the IRP, the Company seeks to formulate an effective resource strategy that is reasonably expected to provide cost-effective and reliable service.

An overview of the process by which the IRP is developed is shown in Figure IV-A-1 below.

FIGURE IV-A-1: ALABAMA POWER IRP PROCESS



Using the best information available at the time of its development, the IRP produces an indicative optimized mix of resources to meet customers' future load requirements over a 20-year planning horizon. This provides a reasonable basis for estimating potential capital expenditures that may be required for future generating capacity additions. In the IRP process, supply-side and demand-side options are evaluated and integrated using marginal cost analysis, thus ensuring that both options are available for potential selection and deployment when they represent a viable economic choice.

When developing the IRP, the Company begins by establishing reliability criteria while assessing the System's overall reliability needs. Prudent utility practice requires that electric utilities maintain sufficient supply-side and demand-side resources to reliably serve the needs of their customers. The ability of such resources to meet electrical demand and maintain an appropriate level of System reliability is referred to in the electric utility industry as "resource adequacy." The appropriate level of System reliability is established for each season pursuant to a comprehensive Reserve Margin Study (discussed in greater detail in Section IV.E.). Through this study process, the Company establishes seasonal TRMs that provide the appropriate level of reliability for the System. The Company also undertakes capacity equivalence studies to ensure that resources relied upon for System reliability are assigned the appropriate capacity value or reliability benefit.

Once established, the seasonal TRMs are applied to the demand and energy forecasts (described further in Section IV.B) to determine the total amount of capacity that is required to meet projected conditions over the planning horizon. The Company determines its capacity need for each season (summer and winter) by calculating the difference in megawatts between existing, planned, and committed supply- and demand-side resources and the forecasted seasonal peak demand plus the applicable TRM requirement. This comparison establishes the amount and timing of future capacity additions that are needed to maintain appropriate System reliability.

The Company next seeks to identify appropriate assumptions and options that comprise inputs to the IRP process. This involves updating the information needed for the generic expansion plan analysis, such as cost and performance of future technology options, fuel cost, and other key inputs. Because the future is inherently uncertain, numerous scenarios with varying planning assumptions are developed to help understand the potential effect of these uncertainties and thus further inform resource planning by the Company. Nine scenarios were created for Budget 2025 ("B2025"), as described in further detail in Section IV.C.

Finally, using the information assembled in the prior steps, the Company performs an expansion planning modeling analysis, or resource mix study, that identifies an optimized least-cost generic resource mix. Based on the modeling parameters and input assumptions, this process seeks to minimize System cost while complying with reliability criteria and environmental laws and regulations. The modeling analysis is conducted for each of the identified scenarios, thus producing a robust set of results that help identify potential resource solutions across a range of uncertainties.

The Benchmark Plan resulting from the IRP process (described in Section IV.I) is a valuable tool that provides an indicative roadmap of potential cost-effective resource options to meet future needs and serves as a basis for more detailed production cost modeling and analyses. This, in turn, informs the Company as it pursues opportunities for capacity and energy resources to address future needs, with the overarching objective being to secure the most cost-effective and reliable options for the benefit of customers. Information derived from the Benchmark Plan, such as marginal costs, is also used to perform resource-specific economic evaluations for both demand-side and supply-side options. Once resource decisions are made, they become inputs that inform subsequent IRP processes.

IV.B. LOAD FORECAST

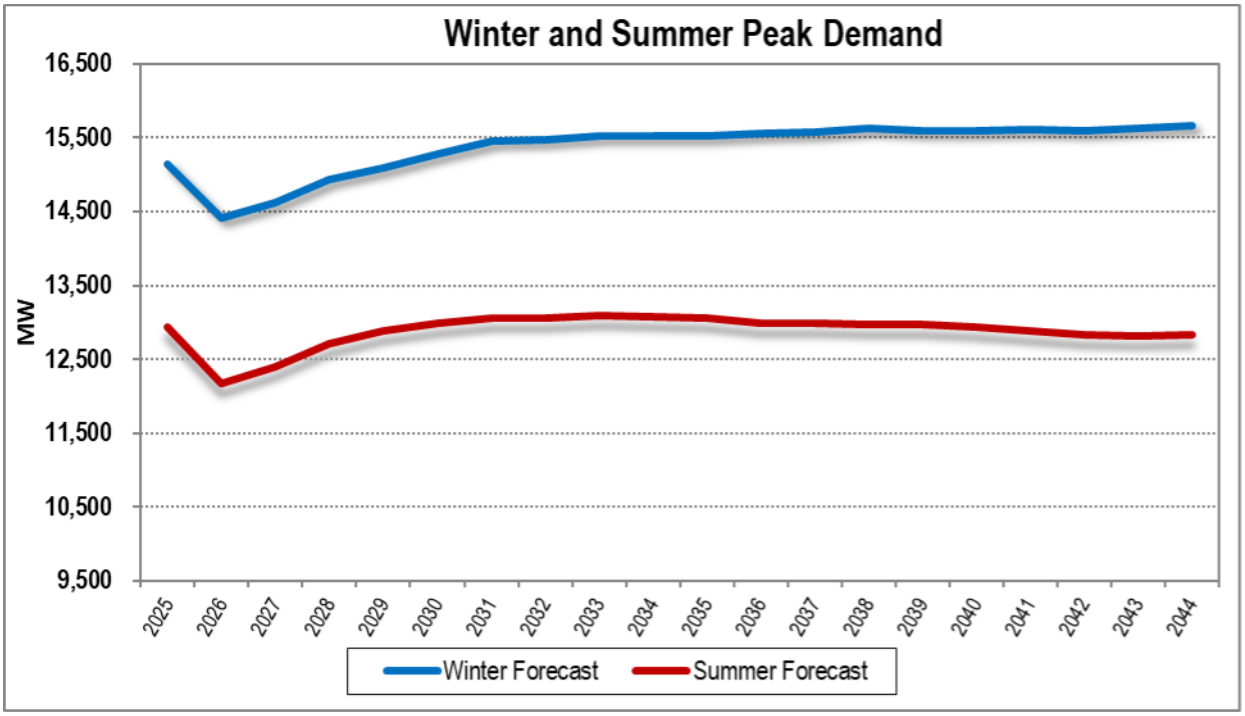
The Company annually produces a long-term energy and peak demand forecast for territorial customers of Alabama Power, including projections of customer growth, peak demand (MW), and monthly energy consumption (kWh). Underlying this load forecast are economic data and forecasts supplied by S&P Global. This information includes available employment and demographic data as well as other economic indicators for the State of Alabama, all of which support the development of econometric models used in the forecasts. The other major input, customer electricity consumption, is typically less correlated with economic growth and more related to trends in end-use equipment efficiencies (e.g., new HVAC equipment, LED light bulbs) and other factors (e.g., electric vehicles).

While the total Residential class electricity consumption has been essentially flat over the past decade due to competing customer growth and increased adoption of appliance efficiencies, the forecast projects an overall increase in electricity consumption for the Residential class over the forecast horizon driven by increased electric vehicle adoption and increases in electrification of other end-uses in the home over the long term. Electricity consumption in the Commercial class has been declining due to customer adoption of efficiency trends outweighing total customer gains in the past decade. While those trends are expected to continue, anticipated additions of large load customers (e.g., data centers) are forecasted to drive an overall increase in Commercial class electricity consumption over the forecast horizon as well.

Alabama remains a heavy manufacturing state. Industrial class energy sales are forecasted by segment and are heavily dependent on projections of manufacturing employment and industrial production as well as the level of deployment of economic development projects in the State of Alabama. While total Industrial class sales have declined over the past several years due to plant closures and pandemic driven supply chain disruptions, Industrial class electricity consumption is projected to increase over the forecast horizon due to continued investment to expand and electrify existing Industrial sites as well as several large economic development projects coming online before the end of the decade.

In addition to the Company's Retail class customers, the 2025 IRP reflects the continuation of the CPO Agreement with PowerSouth. Under the terms of that agreement, PowerSouth load and generating resources are included with the Company's load and resources for optimized commitment and dispatch of all resources. In 2025, PowerSouth's energy sales are forecasted to be approximately 9,900 GWh, with an additional peak load of 2,520 MW included in the Company's forecasted winter peak demand. Figure IV-B-1 below shows this combined peak demand forecast for the winter and summer seasons from 2025-2044.

FIGURE IV-B-1: ALABAMA POWER PEAK DEMAND FORECAST



The decline shown in the figure above in the year 2026 reflects the loss of wholesale load previously served under contracts that will expire at the end of 2025. The average annual summer peak demand growth rate is expected to be approximately 0.10 percent from 2025 through 2030 and -0.09 percent between 2030 and 2044. The average annual winter peak demand growth rate is expected to be approximately 0.19 percent from 2025 to 2030 and approximately 0.17 percent from 2030 through 2044. These projected growth rates for winter peak are about the same as those shown in the 2022 IRP, with higher load levels reflecting economic growth in the Company's service territory. The table below provides the annual peak demand forecast for the summer and winter seasons from 2025-2044 along with annual growth rates.

FIGURE IV-B-2: ALABAMA POWER PEAK DEMAND FORECAST

Year	Winter Peak Demand (MW)	Growth	Summer Peak Demand (MW)	Growth
2025	15,147	0.73%	12,933	1.02%
2026	14,406	-4.89%	12,174	-5.87%
2027	14,626	1.53%	12,403	1.88%
2028	14,939	2.14%	12,720	2.56%
2029	15,099	1.07%	12,885	1.30%
2030	15,290	1.26%	12,995	0.85%
2031	15,465	1.14%	13,053	0.45%
2032	15,471	0.04%	13,067	0.11%
2033	15,525	0.35%	13,095	0.21%
2034	15,532	0.05%	13,084	-0.08%
2035	15,533	0.01%	13,055	-0.22%
2036	15,558	0.16%	12,997	-0.44%
2037	15,583	0.16%	12,983	-0.11%
2038	15,625	0.27%	12,979	-0.03%
2039	15,595	-0.19%	12,981	0.02%
2040	15,602	0.04%	12,945	-0.28%
2041	15,609	0.04%	12,886	-0.46%
2042	15,595	-0.09%	12,840	-0.36%
2043	15,633	0.24%	12,825	-0.12%
2044	15,664	0.20%	12,829	0.03%

IV.C. SCENARIO DESIGN OVERVIEW

Many factors affecting resource planning involve future uncertainties. To this end and as part of the coordinated planning process, the Company (working with the other retail Operating Companies and SCS) creates scenarios to help understand the potential effect of these uncertainties and thus better inform its planning process. Key uncertainties currently affecting planning include: (1) future pressure on greenhouse gas ("GHG") emissions (e.g., CO2), including the 111 GHG Rules; (2) cost and performance of future generating technologies; (3) future electricity consumption; and (4) future fuel prices, especially natural gas.

To construct its planning scenarios, the Company identifies reasonably plausible views of the future that are meaningfully different from one another in each of these four areas. These views are then combined to create various scenarios. For each scenario, the Company uses the Aurora modeling system to identify an indicative least-cost expansion plan that reliably meets load and satisfies many other conditions. For B2025, the Company assembled multiple views of the described areas into nine distinct planning scenarios, as summarized in Table IV-C-1.

Given pending legal challenges to the 111 GHG Rules as well as recent initiatives by the EPA to modify those regulations, the Company has divided its scenarios into two sets. The first set, comprising three scenarios, adopts the view that the 111 GHG Rules remain in effect. The other set of six scenarios adopts the view that the 111 GHG Rules do not remain in effect but nonetheless continues to reflect a measure of GHG-related pressure. All nine scenarios differ from one another by adopting a diverse set of plausible, meaningfully different views of the future evolution of the key resource planning drivers.

FIGURE IV-C-1: B2025 SCENARIO DESIGN

Scenario	GHG pressure view	Tech view	Load view	Fuel view	Label
1	111	Tech Portfolio	Standard	Moderate	111-MG0
2	111	Tech Portfolio	Standard w/ HG0 delta	Higher	111-HG0
3	111 + Higher	IRA 2035	Standard	Moderate	111-MG50

Scenario	GHG pressure view	Tech view	Load view	Fuel view	Label
4	Lower	Tech Portfolio	Standard	Lower	LG0
5	Lower	Tech Portfolio	Standard	Moderate	MG0
6	Lower	Tech Portfolio	Standard w/ HG0 delta	Higher	HG0
7	Moderate	IRA 2045	Standard	Moderate	MG20
8	Higher	IRA 2035	Standard	Moderate	MG50
9	Emissions Limit	IRA 2045	Standard	Moderate	EL

The B2025 scenario design recognizes future pressure on CO2 emissions as a key driver of the Company's long-term planning. In constructing each scenario, views in each of the other areas – technology, load, and fuels – were assembled to be consistent with the view of GHG pressure in the scenario. For example, the technology view is designed so that availability of the 2022 Inflation Reduction Act ("IRA") tax credits[6] is assumed to continue until the end of the modeling horizon in scenarios with the 111 or Lower views of future GHG pressure and to end earlier otherwise. In the Tech Portfolio view, the IRA tax credits are assumed to be available throughout the modeling horizon. In Table IV-B-1, "IRA 20xx" indicates the last begin-construction year assumed for purposes of IRA tax credit availability.

IV.D. FUEL FORECAST

Both short-term (current year plus two) and long-term (year four and beyond) fuel and allowance price forecasts are developed for use not only in the Company's planning activities, but also for application to business case analyses and other appropriate decisions. Short-term forecasts are updated monthly as part of the Company's fuel budgeting process and marginal pricing dispatch procedures. For its long-term fuel price forecasts, the Company adopts the fuel price projections developed each year by the U.S. Energy Information Administration ("EIA") for its Annual Energy Outlook ("AEO").

The AEO presents several scenarios. Each scenario is the result of analysis conducted using the National Energy Modeling System ("NEMS"), which is an integrated multi-sector model simulating the evolution of the United States energy economy to 2050 under different sets of input assumptions. For its views of future prices of natural gas, coal and oil, the Company adopts the results from three of these scenarios: the Reference case, the High Oil and Gas Supply case, and the Low Oil and Gas Supply case. Within each scenario, the fuel price paths are consistent with one another and with expected supply and demand feedbacks across key markets and regions of the economy. This integrated approach takes a set of assumptions about market fundamentals and then solves for the prices that make the quantity supplied equal to the quantity demanded in all markets. In addition, the integrated approach simulates interactions among different markets and thereby reveals how factors such as environmental regulations and overall fuel supply outlooks shape the disposition of economic output across sectors.

[6]The IRA, signed into law in 2022, included Clean Electricity tax incentives for carbon capture and sequestration ("CCS") under section 45Q and new zero-carbon technologies (e.g., solar, wind, storage, nuclear) under sections 45Y (production tax credit or "PTC") and 48E (investment tax credit or "ITC"). The PTCs and ITCs were to begin to phase out at the later of 2032 or when nationwide electric sector carbon emissions reach 25 percent of 2022 levels. In July 2025, the One Big Beautiful Bill Act ("OBBBA") was signed into law, significantly limiting tax credit eligibility under 45Y and 48E, particularly for solar and wind. The 2025 IRP was developed prior to the OBBBA and thus does not reflect its effects. This change in law will be included in the modeling used for subsequent IRPs.

IV.E. RESERVE MARGIN

Electric utility customers expect and depend on a high level of service reliability. Accordingly, a retail electric utility is expected to have an appropriate "reserve margin" representing an economically balanced amount of generating capacity above its anticipated peak load. While uninterrupted service obviously cannot be guaranteed, the objective of the reserve margin is to enable the utility to maintain reliable service to its customers, even when demand is higher than expected or unanticipated events adversely affect sources of supply. Reserve planning is performed on both a short-term and longer-term basis, as uncertainty increases with time and the process to procure additional capacity can take several years. A reserve margin study facilitates the identification of an appropriate amount of reserve capacity that should be targeted at any point in the future.

As for the System specifically, maintaining sufficient reserve capacity allows the Operating Companies to serve customer demand reliably, notwithstanding unpredictable factors such as:

- **Weather Uncertainty:** The System's "weather-normal" load forecasts are based on average weather conditions over more than forty years. If the weather is hotter than normal during warm seasons or colder than normal during cold seasons, the load will be higher. Compared to an average year, the System's peak demand can be as much as 11.1 percent higher in a hot summer year and 24.5 percent higher in a cold winter year.

- **Load Forecast Uncertainty:** It is difficult to project how many new customers will request electric service or how much power existing customers will use from season to season. Due to economic uncertainty across the United States and challenges modeling future usage, the System peak demand may grow by 5.2 percent more than expected over a four- to five-year period.

- **Unit Performance:** While the Operating Companies maintain low forced outage rates for their respective units, machines will necessarily fail from time to time, especially during periods of extreme weather conditions. Indeed, there have been occasions in the last fifteen years when more than 10 percent of the capacity of the System has concurrently been subject to a forced outage.

- **Market Availability Risk:** The ability to obtain resources on short notice from the market when needed to address a short-term System resource adequacy issue can vary. As a general proposition, access to neighboring regions with load and resource diversity enhances reliability. However, the amount, cost and deliverability of those resources at any given time are subject to the external region's own resource-adequacy situation or transmission constraints. This necessarily results in an element of uncertainty regarding the availability of such external support when it is needed. While a region can expect some level of support from its neighbors, each region must carry adequate reserves and manage its own reliability risks.

While each of these factors on its own creates a need for capacity reserves, their aggregate effect poses a considerable reliability risk. A utility seeking to eliminate all such risk to reliability would require a very large amount of reserve capacity that would come at a significant cost. The more appropriate approach is to establish a reasonable reserve margin that seeks to minimize the combined costs of maintaining reserve capacity, System production costs, and customer costs associated with service interruptions, and then adjust the result for the value at risk. This approach results in the Economic Optimum Reserve Margin ("EORM"), properly adjusted for risk. Even then, the risk-adjusted EORM must meet a minimum reliability threshold. Common practice in the industry regarding this threshold is to plan for an annual Loss of Load Expectation ("LOLE") of no greater than 0.1 days per year, which is typically referred to as a "one event in ten years" criterion ("1:10 LOLE"). Because the annual LOLE threshold includes both winter and summer seasons, a reliability change in one season can impact the TRM in the other season if the maximum 1:10 LOLE threshold is to be maintained.

Defining Target Reserve Margins

The traditional formulation of the Summer TRM is stated in terms of weather-normal summer peak demands and summer capacity ratings according to the following formula:

$$STRM=(TSC-SPL)/SPL \times 100$$

Where:
STRM = Summer Target Reserve Margin
TSC = Total Summer Capacity
SPL = Summer Peak Load

The Winter TRM is similarly derived, but uses weather-normal winter peak demands and winter capacity ratings:

$$WTRM=(TWC-WPL)/WPL \times 100$$

Where:
WTRM = Winter Target Reserve Margin
TWC = Total Winter Capacity
WPL = Winter Peak Load

Target Reserve Margins (TRMs)

Based on the analysis of the load forecast and weather uncertainties, the cost of expected unserved energy, and the projected generation reliability of the System reflected in the 2024 RMS, the Company is increasing the current 16.25 percent long-term System TRM for summer peak planning to 20 percent. For winter peak planning, the Company is maintaining the current 26 percent System long-term TRM.

The annual 1:10 LOLE threshold within the System has typically occurred at reserve margins at or below the EORM. Accordingly, the primary focus in establishing the TRM has been the economic analysis. However, as the Company continues to update reliability risks in its modeling, the 2024 RMS has indicated that the LOLE threshold, particularly in the winter season, is now higher than in years past.

The Company's analysis for the winter-only season revealed that maintaining the current 26 percent Winter TRM along with the existing 16.25 percent Summer TRM results in an annual LOLE of one event in eight years. Accordingly, either the Winter TRM or the Summer TRM would have to be increased in order to satisfy the requisite 1:10 LOLE threshold.

The Reserve Margin Study shows that, because resources procured for the winter season are typically available in the summer season as well, the 26 percent Winter TRM corresponds to a Summer TRM of 24.76 percent. Therefore, raising the Summer TRM to 20 percent is not anticipated to drive a System capacity need. Since the Company's projection of capacity needs is driven by the forecast of winter peak demand and Winter TRM, the change in the Summer TRM is not expected to require any resource additions. Consistent with this revision, the short-term Summer TRM is increasing to 19.50 percent, while the short-term Winter TRM continues to be 25.50 percent.

The Winter TRM remains higher than the Summer TRM due to continued reliability risks that are unique to the winter season. Primary drivers for winter risk include: (1) the narrow difference between the System's summer and winter weather-normal peak loads; (2) the distribution and duration of peak loads relative to the norm; (3) occurrence of unit outages due to cold weather; (4) greater penetration of solar resources; (5) the risk of fuel delivery disruption due to winter conditions; and (6) decreased supply alternatives from the wholesale power markets.

As noted earlier, one of the benefits of operating as part of the Southern Pool is that each Operating Company can carry fewer reserves than would otherwise be required by the System target. Thus, Alabama Power's diversified Summer TRM is 19.09 percent over the long-term and 18.58 percent over the short-term. Similarly, the diversified Winter TRM is 25.13 percent over the long-term and 24.61 percent over the short-term. Changes in the load of each Operating Company relative to the loads of the others can impact this diversification effect.

Figure IV-E-1 and Figure IV-E-2 depict the projected diversified winter and summer reserve margins for Alabama Power through 2044, absent any change in resources. As shown, the Company's winter reserve margin is projected to be below both its diversified long-term Winter TRM (25.13 percent) and its diversified short-term Winter TRM (24.61 percent) for the planning timeframe after 2028. Figure IV-E-1 provides the corresponding capacity amounts that would address Alabama Power's reliability deficits for the winter periods. As shown on Figure IV-E-2, resolving the shortfalls in the winter periods with resources available year-round will also resolve any corresponding shortfalls during summer periods, with the Company being consistently above the current Summer TRM until 2040.

FIGURE IV-E-1: ALABAMA POWER PROJECTED WINTER CAPACITY NEEDS

Capacity Need (MW) - Winter		
Year	**Target Reserve Margin (%)**	**Capacity Need (MW)**
2025	24.61	(108)
2026	24.61	(650)
2027	24.61	(390)
2028	25.13	(150)
2029	25.13	1,179
2030	25.13	1,403
2031	25.13	1,607
2032	25.13	1,639
2033	25.13	1,790
2034	25.13	1,968
2035	25.13	2,478
2036	25.13	2,873
2037	25.13	2,899
2038	25.13	2,942
2039	25.13	3,139
2040	25.13	3,145
2041	25.13	4,114
2042	25.13	4,596
2043	25.13	5,037
2044	25.13	5,101

FIGURE IV-E-2: ALABAMA POWER PROJECTED SUMMER CAPACITY NEEDS

Capacity Need (MW) - Summer		
Year	Target Reserve Margin (%)	Capacity Need (MW)
2025	18.58	(2,721)
2026	18.58	(3,335)
2027	18.58	(2,990)
2028	19.09	(1,661)
2029	19.09	(1,286)
2030	19.09	(1,154)
2031	19.09	(1,086)
2032	19.09	(1,032)
2033	19.09	(922)
2034	19.09	(786)
2035	19.09	65
2036	19.09	1
2037	19.09	(12)
2038	19.09	(17)
2039	19.09	205
2040	19.09	1,084
2041	19.09	1,472
2042	19.09	1,787
2043	19.09	1,813
2044	19.09	2,503

IV.F. RESILIENCY NEEDS

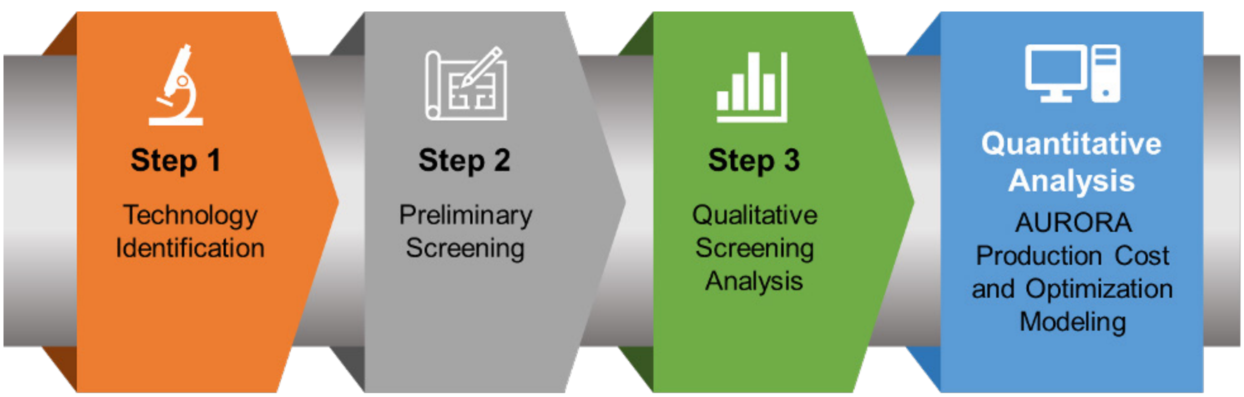
The Company seeks to maintain a robust and resilient electric system that is capable of reliably delivering electric energy, even in the face of unexpected events and disruptions. In general terms, a resilient electric system can withstand and mitigate the effects of disruptive events through the ability to anticipate, adapt to, and recover from such an event. The Company has an excellent track record of managing and planning for reliability risk through its reserve margin process, transmission planning analysis, and similar reliability studies, while also demonstrating substantial commitment to infrastructure protection initiatives. As the Company's generation fleet continues to evolve, there is the need for increased attentiveness to resource availability risk inherent in the provision of reliable electric service to customers. Additionally, the threat of high-impact, low probability events, such as physical and cyber-attacks, continues to grow. With a robust and resilient electric system, the Company is positioned to respond to these and other such challenges.

IV.G. TECHNOLOGY SCREENING

The Company performs detailed expansion planning and production cost analysis during each IRP process. In connection with this effort, the Company completes a screening assessment of new generation technologies to identify a manageable list of potential supply-side technologies that are likely to be economically competitive. This technology screening assessment evaluates both established and emerging generating technologies. The objective is to assess the cost, maturity, safety, operational reliability, flexibility, economic viability, environmental acceptability, fuel availability, construction lead times, and other relevant factors of new supply-side generation options.

The technology screening process includes three main steps: (i) Technology Identification; (ii) Preliminary Screening; and (iii) Detailed Qualitative Screening. Supply-side options identified through this process are then considered in more detailed expansion plan modeling.

FIGURE IV-G-1: TECHNOLOGY SCREENING PROCESS



The screening process is useful for comparing the relative costs of resource types, providing guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process. This more detailed analysis is necessary to determine a long-term resource plan because future units must be optimized with an existing system containing various resource types.

Expansion Plan Candidate Resources

As electricity generating technology is always evolving, the Company's screening process identifies those technologies that have the greatest possibility of serving a cost-effective role in the System during the modeling horizon. Even among the technologies that might play such a role, there remains uncertainty about the cost of each technology relative to its expected productivity and other technology options.

For B2025 analyses, the technologies identified as potentially cost-effective included natural gas combined cycle ("NGCC") (with and without carbon capture sequestration ("CCS")), natural gas combustion turbine with selective catalytic reduction ("SCR") systems (oil-fueled in winter), solar photovoltaic, wind, nuclear (AP-1000), lithium-ion battery energy storage systems ("BESS"), and medium duration energy storage (12-hour option) ("MDESS"). In addition, NGCC with CCS passed initial screening based on an assumed trajectory of technology and infrastructure development towards future commercial availability. While this trajectory and the ultimate cost remain highly uncertain, the inclusion of NGCC with CCS allows the Company to evaluate scenarios for this potential future resource option. Table IV-G-2 summarizes select modeling assumptions associated with the candidate expansion technologies. Note that for certain technologies, such as NGCC with CCS, there may be additional infrastructure or technology limitations that are not yet well understood at this time and are not captured in the model. As observed earlier, the EPA is currently considering changes to the 111 GHG Rules that, if finalized, could materially alter assumptions underlying some of these technology assessments. Finally, it should be emphasized that the Company appropriately considers other means of securing resources, such as site-specific options and market opportunities, that likewise could prove to be a cost-effective solution for customers.

TABLE IV-G-2: CANDIDATE TECHNOLOGY ASSUMPTIONS

Technology	First Year Available	Last Year Available	Modeling Limitations	IRA Applicability
NGCC	2029	111: available through planning horizon; limited to 40% capacity factor beginning 2032 Lower CO2: 2039 Moderate, Higher, & EL CO2: 2036	Market options (2029 limited to 900 MW) Natural gas firm transportation (“FT”) availability	N/A
NGCC with CCS (local sequestration)	2037	Available through planning horizon	FT availability Limited based on geology	45Q Tax Credit COD before 2039
NGCC with CCS (distant sequestration)	2037	Available through planning horizon	FT availability	45Q Tax Credit COD before 2039
CT with SCR	2029	Available through planning horizon	Oil operation in winter months (Dec-Jan-Feb) 20% capacity factor annually	N/A
Solar PV	2028	Available through planning horizon	1,500 MW/year	PTC (45Y) Tech: Planning horizon IRA 2045: COD by 2049 IRA 2035: COD by 2039
Wind	2033	Available through planning horizon	300 MW/year 4,500 MW total	PTC (45Y) Tech: Planning horizon IRA 2045: COD by 2049 IRA 2035: COD by 2039
BESS	2028	Available through planning horizon	3,000 MW/year	ITC (48E) Tech: Planning horizon IRA 2045: COD by 2049 IRA 2035: COD by 2039
MDESS	2033	Available through planning horizon	3,000 MW/year	ITC (48E) Tech: Planning horizon IRA 2045: COD by 2049 IRA 2035: COD by 2039
Nuclear (AP-1000)	2037	Available through planning horizon	600 MW/year	ITC (48E) Tech: Planning horizon IRA 2045: COD by 2053 IRA 2035: COD by 2043

Natural Gas Combined Cycle (NGCC) without Carbon Capture: The B2025 IRP assumption for planning purposes is that generic NGCC plants (without carbon capture facilities) are available for fleet expansion beginning in 2030 and only through 2039. The 111 view requires that all new NGCC plants without CCS be limited to a 40% capacity factor beginning in 2032 through the planning horizon. The timing of this assumption is based on the Company's understanding of the Clean Air Act and corresponding regulations as they exist today, along with the applicable schedule for review of abatement technologies and emission control requirements (i.e., New Source Performance Standards and Best Available Control Technology).

Natural Gas Combined Cycle (NGCC) with Carbon Capture: The B2025 IRP assumption for planning purposes is that generic NGCC plants with CCS are available for fleet expansion beginning in 2037. The cost and performance characteristics assumed for the NGCC with CCS technology are a proxy for various forms of efficient gas-fueled technologies that separate their CO2 for disposal, including post-combustion capture and supercritical CO2 (Allam cycle). The geology for CO2 storage is not uniform across the System's territory. For the System modeling analysis, it is assumed that a limited amount of NGCC with CCS could be sited near "local" sequestration sites; additional NGCC with CCS would require a longer (and more expensive) pipeline to transport the captured CO2 for more distant sequestration sites. The planning assumption is that beginning in 2040 new NGCC plants must capture 90 percent of their carbon dioxide emissions. The timing of this assumption is based on the Company's understanding of the Clean Air Act and corresponding regulations as they exist today, along with the applicable schedule for review of abatement technologies and emission control requirements (i.e., New Source Performance Standards and Best Available Control Technology). The Company assumes that the 45Q tax credit is available for NGCC with CCS whose construction starts by the end of 2032.

Natural Gas Combustion Turbines (CT): The B2025 IRP assumption for planning purposes is that dual-fuel CTs with SCR are available for fleet expansion beginning in 2029 and are assumed to operate on oil in the winter months and natural gas in all other months. Combustion turbines must significantly reduce their NOx emissions by being equipped with a SCR device. This assumption is consistent with recent deployments of this technology across the industry and the Company's understanding of the existing Clean Air Act and its statutory requirements for review of abatement technologies and requirements.

Solar PV: Solar PV with single-axis tracking is available as an expansion resource beginning in 2028. The B2025 IRP assumes that the cost of solar will continue to decline in real terms, meaning it will become increasingly cost-effective through the study timeframe. It also assumes that solar will receive clean electricity production tax credits (PTCs) for 10 years as provided in the Inflation Reduction Act (IRA). In scenarios adopting the Lower view of future CO_2 pressure, the PTCs are assumed to be available for solar installed at any time in the modeling horizon; in other scenarios the credits are assumed to be available for solar whose construction starts by 2045 (scenarios adopting the Moderate or Emissions Limit views of future CO_2 pressure) or by 2035 (scenarios adopting the Higher view of future CO_2 pressure). Solar is limited to 1.5 GW per year (including planned and committed solar).

Wind: Wind is available as an expansion resource beginning in 2033. The B2025 IRP assumes that wind will receive clean electricity PTCs for 10 years as provided in the IRA. In scenarios adopting the Lower view of future CO_2 pressure, the PTCs are assumed to be available for wind installed at any time in the modeling horizon; in other scenarios the credits are assumed to be available for solar whose construction starts by 2045 (scenarios adopting the Moderate or Emissions Limit views of future CO_2 pressure) or by 2035 (scenarios adopting the Higher view of future CO_2 pressure). Wind is limited to 0.3 GW per year and 4.5 GW total during the modeling horizon.

Battery Energy Storage System (4-hour option): BESS is available as an expansion resource beginning in 2028. The B2025 IRP assumes that BESS costs will continue to decline into the middle of the planning horizon, before leveling off in real terms, meaning that it will become increasingly cost-effective throughout the study timeframe. The Company assumes that BESS will receive the ITCs as provided in the IRA. In scenarios adopting the Lower view of future CO_2 pressure, the ITCs are assumed to be available for BESS installed at any time in the modeling horizon; in other scenarios the credits are assumed to be available for BESS whose construction starts by 2045 (scenarios adopting the Moderate or Emissions Limit views of future CO_2 pressure) or by 2035 (scenarios adopting the Higher view of future CO_2 pressure). BESS is limited to 3 GW per year. The capacity contribution of incremental BESS installations decreases as more BESS is added to the resource mix.

Medium Duration Energy Storage System (12-hour option): MDESS is available as an expansion resource beginning in 2033. The modeled cost and performance of MDESS is a proxy for either pumped thermal energy storage or compressed air energy storage ("CAES"). The B2025 IRP assumes that MDESS will receive the ITCs as provided in the IRA. In scenarios adopting the Lower view of future CO_2 pressure, the ITCs are assumed to be available for MDESS installed at any time in the modeling horizon; in other scenarios the credits are assumed to be available for battery storage whose construction starts by 2045 (scenarios adopting the Moderate or Emissions Limit views of future CO_2 pressure) or by 2035 (scenarios adopting the Higher view of future CO_2 pressure). Build limits have not been applied to MDESS in the modeling study.

Nuclear: Nuclear units (AP-1000) are available as an expansion resource beginning in 2037. The B2025 IRP assumes that nuclear units will receive the ITCs as provided in the IRA. In scenarios adopting the Lower view of future CO2 pressure, the ITCs are assumed to be available for nuclear installed at any time in the modeling horizon; in other scenarios the credits are assumed to be available for nuclear units whose construction starts by 2045 (scenarios adopting the Moderate or Emissions Limit views of future CO2 pressure) or by 2035 (scenarios adopting the Higher view of future CO2 pressure). Nuclear is limited to 0.6 GW per year.

Aurora selects new units from among the available technologies based on minimizing total operating and capital costs. To minimize the potential for bias resulting from the different MW sizes of available expansion resources, a unit size of 300 MW was considered for all technologies. The model adds resources in multiples of 300 MW.

IV.H. DEVELOPMENT OF INDICATIVE RESOURCE ADDITIONS

The Company's expansion planning analysis identifies an optimized mix of resources designed to satisfy future capacity and energy demands in an economic and reliable manner. In this step of the planning process, demand-side resources are integrated with supply-side resources to provide a roadmap that informs long-term resource planning decisions. To be clear, a generic expansion plan does not represent resource planning decisions by the Company, but rather an indicative optimized mix of generic resources based on the IRP's modeling assumptions and inputs.

The purpose of the expansion planning process is to evaluate capacity and energy resource options to meet reliability needs across a wide range of potential future scenarios. To develop a generic expansion plan, the generation technologies that pass detailed screening are further evaluated using the Aurora capacity expansion and production cost model, which is widely used throughout the electric industry. Aurora employs a generation mix optimization module that includes the following major inputs: (1) load forecast; (2) existing, planned and committed resources; (3) fuel prices; (4) emission costs; (5) future generating unit characteristics and capital cost; (6) capital recovery rates; (7) capital cost escalation rates; and (8) a discount rate. The Aurora model iteratively evaluates combinations of resource additions that satisfy the Company's annual TRMs and identifies a least-cost expansion plan that minimizes production and capital cost over the planning horizon.

A generic expansion plan informs the Company of the type of capacity and energy resources that are most economical within a particular timeframe for the given assumptions. Actual resource decisions may differ from those selected in a generic expansion plan for reasons such as market opportunities, changing economic conditions, unanticipated costs or benefits, and regulatory considerations.

Summary of Inputs and Assumptions:

The expansion planning process incorporates a wide range of inputs and assumptions, including, but not limited to, reliability criteria, load and energy forecasts, and numerous financial and economic scenarios.

- **Reserve Margins** – The 2025 IRP reflects a 20 percent System Summer TRM and a 26 percent System Winter TRM for long-term resource planning decisions.

- **Economic Forecast** – S&P Global's macroeconomic forecast serves as the basis for inflation and cost of capital estimates.

- **Load and Energy Forecasts** – The B2025 Peak Demand and Energy Forecasts discussed in Section IV.B. were utilized for the Company's 2025 IRP generic expansion plan.

- **Fuel Forecast** – The 2025 IRP generic expansion plan incorporates the fuel forecast information described in Section IV.D.

- **Technology** – The 2025 IRP reflects the technology assumptions described in Section IV.G.

- **Financial Cost and Escalation** – The Company assumes that a mix of long-term debt and common stock are issued to finance the construction of generating units. The associated costs can fluctuate due to changes in market conditions (e.g., business risk perception, inflation rates and interest rates). Discount analysis using the weighted average cost of capital is applied to place more emphasis on the near term.

IV.I. BENCHMARK PLAN

As part of the expansion planning process, the Company produces a Benchmark Plan that serves as a reference case. This Benchmark Plan is based on the "MG0" scenario, which reflects a view with moderate gas and zero-dollar carbon, and does not include the 111 GHG Rules. Figure IV-I-1 shows the cumulative capacity and energy resource addition schedule for the Benchmark Plan. Due to uncertainty surrounding the 111 GHG Rules, the Company included an additional Benchmark Plan that includes assumptions reflecting the 111 GHG Rules "111-MG0", as depicted in Figure IV-I-2.

FIGURE IV-I-1: MG0 BENCHMARK PLAN

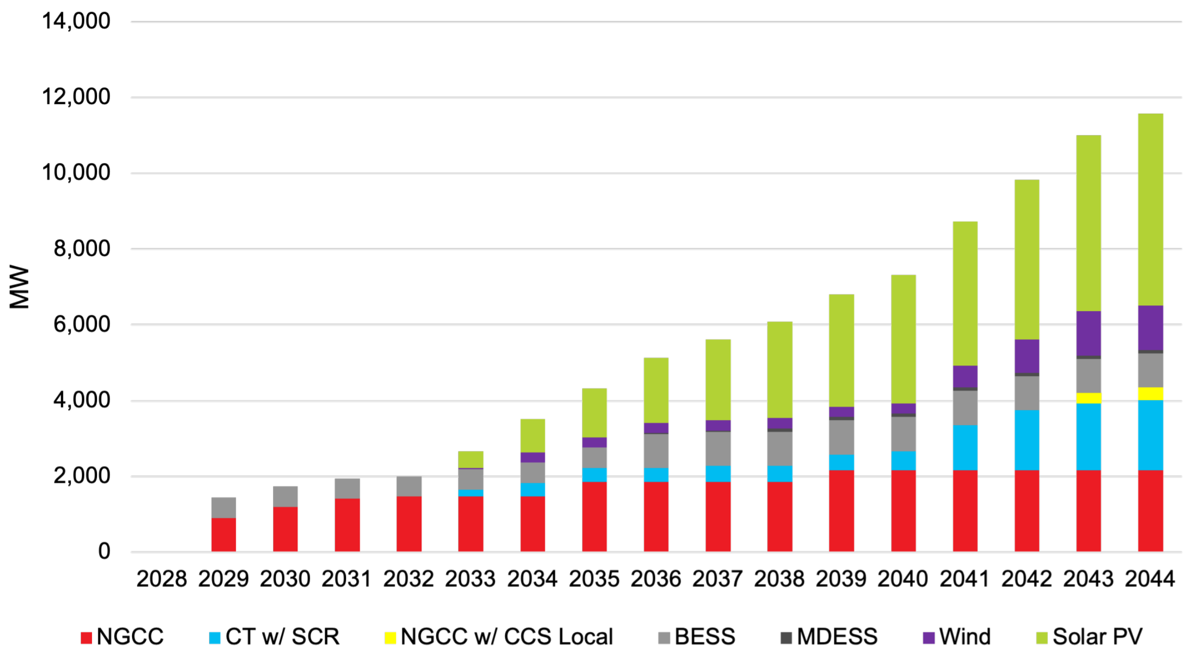
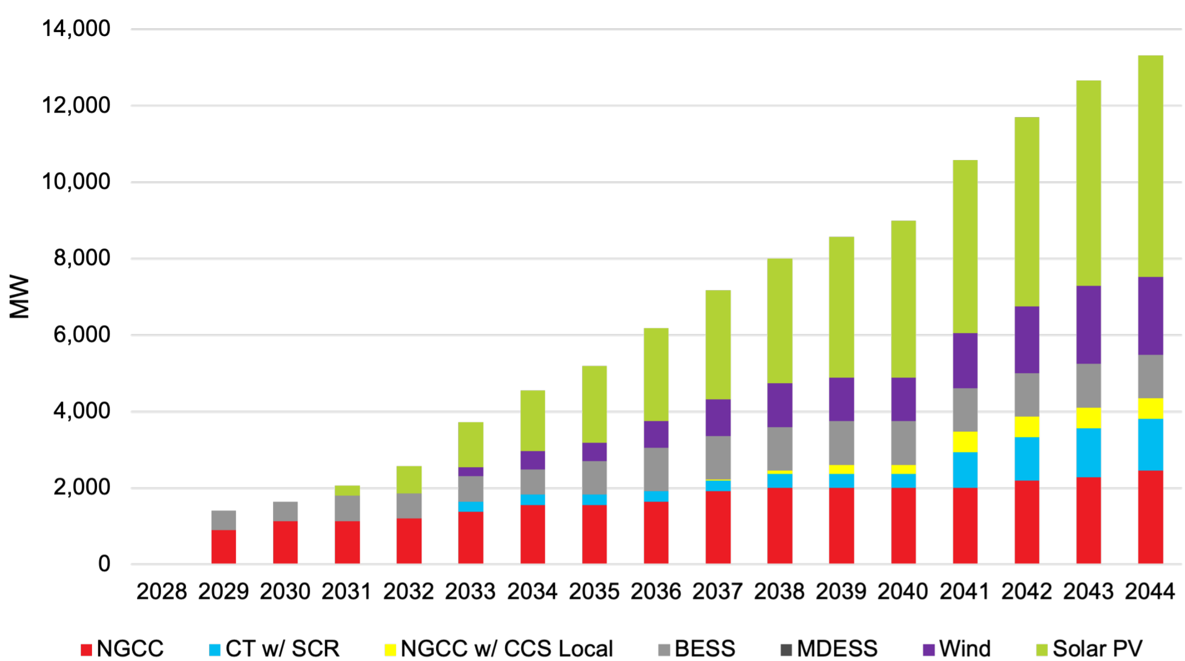
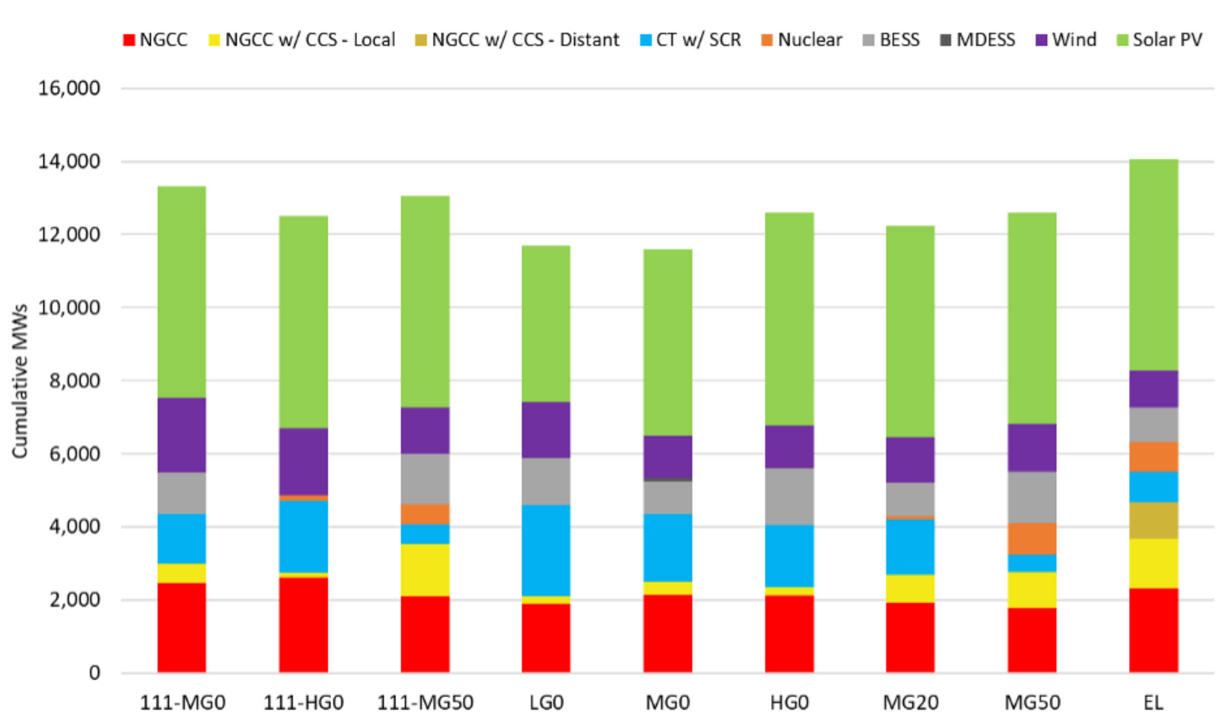


FIGURE IV-I-2: 111-MG0 BENCHMARK PLAN



The results of the resource mix study provide an indicative schedule of economically optimal resource additions for the retail Operating Companies across a range of scenarios, based on the underlying assumptions and various futures described in Section IV.B. These results, as depicted in Figure IV-I-3, are part of a broader range of input information to help inform the Company as it formulates long-term decisions in view of future uncertainties.

FIGURE IV-I-3: B2025 GENERIC EXPANSION PLAN RESULTS – CUMULATIVE MW (2025-2044)



Based on these results, additional generation capacity requirements to meet customer needs may involve a mixture of natural gas CC (with and without CCS), dual-fuel CT with SCR, solar, wind, battery storage, and nuclear.

V. CONCLUSION

The 2025 IRP process summarized in this report yields the Company's resource adequacy projections for the current 20-year horizon. This includes identifying both short- and long-term capacity deficits for Alabama Power, with the former largely addressed through resources certified by the APSC over the last several years. Consistent with its obligation to provide reliable service to its customers, the Company intends to initiate appropriate measures to resolve its long-term needs in a timely manner. This will enable Alabama Power to continue meeting the needs of its customers in a reliable and cost-effective manner over the 20-year planning horizon, consistent with its statutory duties and responsibilities.

APPENDIX 1

ALABAMA POWER COMPANY

EXISTING SUPPLY-SIDE RESOURCES

FIGURE A1-1

Alabama Power Company

Existing Supply-Side Resources

(as of January 2025)

Alabama Power Company Supply-Side Resource Summary						
	Plants	**Units**	**Nameplate/ Contract Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	
Fossil	9	34	10,046	10,264	10,826	
Nuclear	1	2	1,720	1,781	1,823	
Hydro	14	41	1,668	1,695	1,656	
Solar	2	2	18	10	4	
Ownership Total	***26***	***79***	***13,452***	***13,750***	***14,309***	
Contracted Total	***N/A***	***N/A***	***714***	***3,419***	***3,923***	
Total Owned & Contracted			***14,166***	***17,169***	***18,232***	

Fossil Steam Plants						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Barry	1	125	80	80	1954	
	2	125	80	80	1954	
	4	350	368	368	1969	
	5	700	757	800	1971	
Gaston	1	125	127	127	1960	Ratings reflect 50% Alabama Power capacity entitlement
	2	125	128	128	1960	Ratings reflect 50% Alabama Power capacity entitlement
	3	125	127	127	1961	Ratings reflect 50% Alabama Power capacity entitlement
	4	125	128	128	1962	Ratings reflect 50% Alabama Power capacity entitlement
	5	880	890	926	1974	
Greene County	1	150	155	155	1965	Ratings reflect Alabama Power 60% ownership
	2	150	155	155	1966	Ratings reflect Alabama Power 60% ownership
Miller	1	606	652	679	1978	Ratings reflect Alabama Power 91.8% ownership
	2	606	647	682	1985	Ratings reflect Alabama Power 91.8% ownership
	3	660	732	748	1989	
	4	660	746	746	1991	
Total	***15***	***5,512***	***5,772***	***5,927***		

Nuclear Steam Plants						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Farley	1	860	897	907	1975	
	2	860	884	916	1979	
Total	***2***	***1,720***	***1,781***	***1,823***		

Alabama Power Company Supply-Side Resource Summary - cont.

Gas-Fired Plants (Combustion Turbines)						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Greene County	2	80	84	100	1996	
	3	80	82	98	1996	
	4	80	81	97	1995	
	5	80	82	98	1995	
	6	80	81	97	1995	
	7	80	80	96	1995	
	8	80	83	99	1996	
	9	80	82	98	1996	
	10	80	85	101	1996	
Calhoun	1	187	164	188	2003	Units are fueled by oil in winter and gas in summer periods, respectivley
	2	187	164	188	2003	Units are fueled by oil in winter and gas in summer periods, respectivley
	3	187	164	188	2003	Units are fueled by oil in winter and gas in summer periods, respectivley
	4	187	164	188	2003	Units are fueled by oil in winter and gas in summer periods, respectivley
Total	***13***	***1,468***	***1,394***	***1,634***		

Gas-Fired Plants (Combined Cycles)						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Barry	6	535	569	594	2000	
	7	535	567	580	2001	
	8	636	637	687	2023	Ratings reflects Alabama Power capacity entitlement
Central Alabama	1	885	901	947	2003	Ratings reflect Alabama Power capacity entitlement
Washington County	1	123	100	107	1999	Cogeneration plant
Lowndes County	1	105	85	95	1999	Cogeneration plant
Theodore	1	236	231	245	2001	Cogeneration plant
Total	***5***	***3,056***	***3,090***	***3,255***		

Oil-Fired Plants (Combustion Turbines)						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Gaston	A	10	8	10	1970	Ratings reflect 50% Alabama Power capacity entitlement
Total	***1***	***10***	***8***	***10***		

Solar Plants						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Fort Rucker		10.6	4.1	1.5	2017	
ANAD		7.4	5.8	2.1	2017	
Total	***2***	***18.0***	***9.9***	***3.6***		

Contracted Capacity						
Plant		**Contract Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**Start Year**	**Notes**
Chisholm View PPA		202	81	101	2013	
Buffalo Dunes PPA		202	81	101	2014	
LaFayette PPA		72	51	20	2017	
Hog Bayou PPA		238	212	231	2020	Ratings reflect Alabama Power capacity entitlement
Wholesale contract resources (PSEC, AMEA, Tombigbee & Black Warrior EMCs)			2,994	3,471		Includes SEPA hydro allocations to the entities
Total		***714***	***3,419***	***3,923***		

Alabama Power Company Supply-Side Resource Summary - cont.

Hydroelectric Plants							
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Weiss	1	29	27	24	1962	Upper Coosa Group
	2	29	27	24	1961	Upper Coosa Group
	3	29	27	24	1961	Upper Coosa Group
Henry	1	24	24	23	1966	Upper Coosa Group
	2	24	24	23	1966	Upper Coosa Group
	3	24	24	23	1966	Upper Coosa Group
Logan Martin	1	45	43	40	1964	Upper Coosa Group
	2	45	43	40	1964	Upper Coosa Group
	3	45	43	40	1964	Upper Coosa Group
Lay	1	30	30	30	1968	Lower Coosa Group
	2	30	30	30	1968	Lower Coosa Group
	3	30	30	30	1967	Lower Coosa Group
	4	30	30	30	1967	Lower Coosa Group
	5	30	30	30	1967	Lower Coosa Group
	6	30	30	30	1967	Lower Coosa Group
Mitchell	4	20	19	19	1949	Lower Coosa Group
	5	50	48	49	1985	Lower Coosa Group
	6	50	48	49	1985	Lower Coosa Group
	7	50	48	49	1985	Lower Coosa Group
Jordan	1	25	32	33	1928	Lower Coosa Group
	2	25	32	33	1928	Lower Coosa Group
	3	25	32	33	1928	Lower Coosa Group
	4	25	32	33	1928	Lower Coosa Group
Bouldin	1	75	75	75	1967	Lower Coosa Group
	2	75	75	75	1967	Lower Coosa Group
	3	75	75	75	1967	Lower Coosa Group
Martin	1	46	46	44	1926	Tallapoosa Group
	2	41	41	39	1926	Tallapoosa Group
	3	40	40	38	1926	Tallapoosa Group
	4	55	55	52	1952	Tallapoosa Group
Thurlow	1	34	34	33	1930	Tallapoosa Group
	2	34	34	33	1930	Tallapoosa Group
	3	13	13	12	1930	Tallapoosa Group
Yates	1	24	22	23	1928	Tallapoosa Group
	2	24	22	23	1928	Tallapoosa Group
Harris	1	66	67	62	1983	Tallapoosa Group
	2	66	67	62	1983	Tallapoosa Group
Smith	1	79	89	88	1961	Warrior Group
	2	79	89	88	1962	Warrior Group
Bankhead	1	54	53	53	1963	Warrior Group
Holt	1	47	48	48	1968	Warrior Group
Total	***41***	***1,668***	***1,695***	***1,656***		

APPENDIX 2

ALABAMA POWER COMPANY
DEMAND-SIDE MANAGEMENT PROGRAMS

Alabama Power implements DSM measures and programs that are designed to assist with System load shape management (thereby reducing costs and the need for future capital investment), while also promoting the efficient use of energy by the Company's customers. All customer segments (industrial, commercial and residential) are potential participants in these programs.

Changes in technology and other influencing factors can, along with training and education, provide more opportunities for the Company to work with customers to help them manage and control their energy use, making it more efficient and economical. As with existing programs, new programs must be expected to benefit all customers as determined by the Rate Impact Measure ("RIM") test, thereby avoiding a situation where some customers are effectively being caused to subsidize the benefits realized by others.

Alabama Power currently has customers participating in more than 20 DSM programs/rates in the residential, commercial and industrial sectors, as well as programs managed through the Company's Distribution Operations. DSM programs subject to the direct control of the Company (e.g., non-residential interruptible load) are called "active DSM." Programs that influence energy use through customer behavior, pricing signals, or automated technologies—without being directly dispatched by the Company—are considered "passive DSM."

The 2025 IRP includes approximately 1,638 MW of existing contracted active DSM programs that have allowed the deferral of 735 MW of supply-side resource capacity in the winter. The difference between the nominal values shown for these DSM programs and the associated supply-side resource capacity deferrals reflects the capacity equivalence of a given active DSM program, as compared to supply-side resources. The passive DSM programs serve to reduce expected peak load and their effects are embedded in the Company's load forecast. Existing passive DSM programs are estimated to result in a winter peak load reduction of 235 MW. The total contract amount of existing DSM programs reflected in the 2025 IRP is 1,873 MW: 1,638 MW (active) and 235 MW (passive).

The Company has recently exceeded its certificated goal (established in Docket No. 32953) of an incremental 200 MW of cost-effective demand-side and/or distributed energy resources by 2025 to address a portion of its winter peak demand. These programs comprise the following five (5) primary categories that span all three customer classes (residential, commercial and industrial) and cover a variety of customer segments.

- **Beneficial Electrification** – Installation of electric end-use products that save customers money over time and improve comfort and convenience, while also benefiting the electric grid.

- **Customer Rebates and Engagement** – Incentives and tools for customers who implement energy efficient behaviors or adopt technologies that help reduce system demand and improve efficiency.

- **Load Optimization and Flexibility** – Programs that shift demand away from peak periods through event-based control or daily automation, without sacrificing customer comfort.

- **Low-to-Moderate Income/Income Qualified** – Weatherization measures and thermostat programs that improve efficiency for residential customers who meet specific income qualifications.

- **Traditional Curtailment/Demand Response** – Load-reduction programs based on contractual agreements with customers to reduce their demand during critical periods.

As part of its prior DSM development efforts, Alabama Power partnered with a strategic and technical consulting firm to assess potential load reduction opportunities across all customer segments. That analysis, completed in 2022, identified demand-side resource potential beyond traditional industrial curtailment, including residential and commercial load flexibility enabled through automation and emerging technologies. While the Company continues to leverage those findings, it is also actively evaluating additional cost-effective DSM solutions to support system reliability, reduce peak demand, and provide value to customers across both active and passive program categories.

Alabama Power's growing portfolio of programs and pilots includes enhanced marketing and outreach efforts using customers' preferred communication channels to increase awareness, reduce participation barriers, and support informed energy decisions. These efforts recognize that education plays a key role in encouraging enrollment and achieving load reductions. Additionally, Alabama Power's marketing approaches consider the specific needs of low to moderate income customers, with an emphasis on communicating program benefits that do not require upfront investment.

OVERVIEW OF ACTIVE DSM PROGRAMS

Residential

1. Smart Peak (load optimization and flexibility) – A winter and summer season demand response program that uses event-based optimization to pre-condition participants' homes prior to the load reduction events. Eligible customers with Google Nest, Emerson Sensi, Ecobee or Honeywell Home Total Connect Comfort Wi-Fi enabled thermostats can enroll in the program and receive an incentive for their participation.
2. Water Heater Direct Load Control (under consideration) – A residential demand response concept that would allow the Company to control qualifying electric water heaters during system peak events.

Commercial and Industrial

3. Industrial Interruptible Program (contractual curtailment) – This program, which is currently one of the largest of its kind in the nation, allows Alabama Power to call for the interruption of load with 15-30 minutes' notice. The Company's right to interrupt is subject to contractual limitations (e.g., no more than 200-600 hours per year and no longer than 8 hours per call).
4. Standby Generator Program (contractual curtailment) – Under this program, customers enter a contract with Alabama Power to switch to their standby generators for use in non-emergency circumstances. The Company is limited to calling these contracts for not more than 200 hours a year (not including maintenance and testing), with no call exceeding 8 hours.
5. Commercial and Industrial Automated Demand Response (under development) – A demand response program that would allow commercial and industrial customers to reduce load during system events through automated control of building systems or industrial processes.
6. Real Time Pricing (price signal) – Industrial pricing option based on marginal costs plus applicable components to recover fixed costs.

Transmission and Distribution

7. Distribution Regulation Optimization Program (DROP) – A conservation voltage control option that lowers the voltage on distribution feeders to lower the demand and reduce real power requirements on the system. The target activation periods under this program are the summer and winter peaks.

The capacity values (both nominal and deferred capacity equivalence) associated with the above-described active DSM programs, as reflected in the 2025 IRP, are shown in Figure A2-1 Winter and Figure A2-1 Summer.

FIGURE A2 - 1 Winter

INTEGRATED RESOURCE PLAN 2025

Projections of Active Demand-Side Management (DSM) 2025-2044

Active DSM

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Contract Amounts	(1,638)	(1,658)	(1,694)	(1,719)	(1,735)	(1,748)	(1,760)	(1,772)	(1,784)	(1,796)
Resource Deferral Amounts	(735)	(751)	(781)	(801)	(814)	(823)	(832)	(841)	(850)	(858)
	2035	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
Contract Amounts	(1,807)	(1,807)	(1,807)	(1,808)	(1,808)	(1,808)	(1,808)	(1,808)	(1,808)	(1,808)
Resource Deferral Amounts	(867)	(867)	(867)	(867)	(867)	(867)	(868)	(868)	(868)	(868)

Active DSM - Contract Amounts

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
150 & 200 Hour Interruptible	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)
600 Hour Interruptible	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
C&I ADR	0	0	(4)	(9)	(13)	(13)	(14)	(14)	(15)	(15)
Non-Indust. SmartPeak	0	(11)	(22)	(33)	(44)	(55)	(66)	(77)	(88)	(98)
Non-Indust. WH DLC	0	0	(0)	(1)	(1)	(1)	(2)	(2)	(2)	(3)
Customer Standby Generation - 200HR	(4)	(9)	(20)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Customer Standby Generation - 50HR	0	(8)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
Distribution Regulation Option Program (DROP)	(55)	(52)	(53)	(54)	(55)	(56)	(57)	(57)	(57)	(57)
Total Active DSM - Contract Amount	(1,638)	(1,658)	(1,694)	(1,719)	(1,735)	(1,748)	(1,760)	(1,772)	(1,784)	(1,796)
	2035	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
150 & 200 Hour Interruptible	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)
600 Hour Interruptible	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
C&I ADR	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)
Non-Indust. SmartPeak	(109)	(109)	(109)	(109)	(109)	(109)	(109)	(109)	(109)	(109)
Non-Indust. WH DLC	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Customer Standby Generation - 200HR	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Customer Standby Generation - 50HR	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
Distribution Regulation Option Program (DROP)	(57)	(57)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)
Total Active DSM - Contract Amount	(1,807)	(1,807)	(1,807)	(1,808)	(1,808)	(1,808)	(1,808)	(1,808)	(1,808)	(1,808)

Active DSM - Resource Deferral Amounts

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
150 & 200 Hour Interruptible	(667)	(667)	(667)	(667)	(667)	(667)	(667)	(667)	(667)	(667)
600 Hour Interruptible	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
C&I ADR	0	0	(4)	(7)	(11)	(11)	(11)	(12)	(12)	(13)
Non-Indust. SmartPeak	0	(8)	(16)	(24)	(32)	(40)	(48)	(56)	(64)	(72)
Non-Indust. WH DLC	0	0	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(2)
Customer Standby Generation - 200HR	(3)	(8)	(18)	(25)	(25)	(25)	(25)	(25)	(25)	(25)
Customer Standby Generation - 50HR	0	(7)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)
Distribution Regulation Option Program (DROP)	(54)	(51)	(52)	(53)	(54)	(55)	(56)	(56)	(56)	(56)
Total Active DSM - Contract Amount	(735)	(751)	(781)	(801)	(814)	(823)	(832)	(841)	(850)	(858)
	2035	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
150 & 200 Hour Interruptible	(667)	(667)	(667)	(667)	(667)	(667)	(667)	(667)	(667)	(667)
600 Hour Interruptible	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
C&I ADR	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
Non-Indust. SmartPeak	(80)	(80)	(80)	(80)	(80)	(80)	(80)	(80)	(80)	(80)
Non-Indust. WH DLC	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Customer Standby Generation - 200HR	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)
Customer Standby Generation - 50HR	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)
Distribution Regulation Option Program (DROP)	(56)	(56)	(56)	(57)	(57)	(57)	(57)	(57)	(57)	(57)
Total Active DSM - Contract Amount	(867)	(867)	(867)	(867)	(867)	(867)	(868)	(868)	(868)	(868)

Active Demand-Side Management is activated, i.e., dispatchable or controllable programs, by the Company at the time of need. Active DSM is explicitly indicated in the Integrated Resource Plan (IRP) as a resource. Active DSM reflected here are inputs for the 2025 IRP.

FIGURE A2 - 1 Summer

INTEGRATED RESOURCE PLAN 2025

Projections of Active Demand-Side Management (DSM) 2025-2044

Active DSM

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Contract Amounts	(1,682)	(1,701)	(1,718)	(1,729)	(1,738)	(1,741)	(1,746)	(1,750)	(1,754)	(1,758)
Resource Deferral Amounts	(893)	(912)	(928)	(937)	(944)	(947)	(951)	(953)	(956)	(959)
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Contract Amounts	(1,761)	(1,762)	(1,761)	(1,761)	(1,761)	(1,761)	(1,761)	(1,761)	(1,761)	(1,760)
Resource Deferral Amounts	(962)	(962)	(962)	(962)	(962)	(961)	(961)	(961)	(961)	(961)

Active DSM - Contract Amounts

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
150 & 200 Hour Interruptible	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)
600 Hour Interruptible	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
C&I ADR	0	(2)	(6)	(11)	(15)	(13)	(14)	(14)	(15)	(15)
Non-Indust. SmartPeak	(3)	(6)	(10)	(14)	(17)	(21)	(25)	(28)	(32)	(35)
Non-Indust. WH DLC	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Customer Standby Generation - 200HR	(9)	(20)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Customer Standby Generation - 50HR	(8)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
Distribution Regulation Option Program (DROP)	(84)	(78)	(80)	(82)	(83)	(84)	(85)	(85)	(85)	(85)
Total Active DSM - Contract Amount	(1,682)	(1,701)	(1,718)	(1,729)	(1,738)	(1,741)	(1,746)	(1,750)	(1,754)	(1,758)
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
150 & 200 Hour Interruptible	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)	(1,562)
600 Hour Interruptible	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
C&I ADR	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
Non-Indust. SmartPeak	(39)	(39)	(39)	(39)	(39)	(39)	(39)	(39)	(39)	(39)
Non-Indust. WH DLC	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Customer Standby Generation - 200HR	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Customer Standby Generation - 50HR	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
Distribution Regulation Option Program (DROP)	(85)	(85)	(85)	(84)	(84)	(84)	(84)	(84)	(84)	(84)
Total Active DSM - Contract Amount	(1,761)	(1,762)	(1,761)	(1,761)	(1,761)	(1,761)	(1,761)	(1,761)	(1,761)	(1,760)

Active DSM - Resource Deferral Amounts

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
150 & 200 Hour Interruptible	(778)	(778)	(778)	(778)	(778)	(778)	(778)	(778)	(778)	(778)
600 Hour Interruptible	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
C&I ADR	0	(2)	(5)	(9)	(12)	(11)	(12)	(12)	(12)	(13)
Non-Indust. SmartPeak	(2)	(5)	(7)	(10)	(13)	(15)	(18)	(21)	(23)	(26)
Non-Indust. WH DLC	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Customer Standby Generation - 200HR	(9)	(21)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
Customer Standby Generation - 50HR	(8)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)
Distribution Regulation Option Program (DROP)	(87)	(80)	(82)	(85)	(86)	(87)	(88)	(87)	(88)	(88)
Total Active DSM - Contract Amount	(893)	(912)	(928)	(937)	(944)	(947)	(951)	(953)	(956)	(959)
	2,035	2036	2037	2038	2039	2040	2041	2042	2043	2044
150 & 200 Hour Interruptible	(778)	(778)	(778)	(778)	(778)	(778)	(778)	(778)	(778)	(778)
600 Hour Interruptible	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
C&I ADR	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
Non-Indust. SmartPeak	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Non-Indust. WH DLC	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Customer Standby Generation - 200HR	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
Customer Standby Generation - 50HR	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)
Distribution Regulation Option Program (DROP)	(87)	(87)	(87)	(87)	(87)	(87)	(87)	(87)	(87)	(86)
Total Active DSM - Contract Amount	(962)	(962)	(962)	(962)	(962)	(961)	(961)	(961)	(961)	(961)

Active Demand-Side Management is activated, i.e., dispatchable or controllable programs, by the Company at the time of need. Active DSM is explicitly indicated in the Integrated Resource Plan (IRP) as a resource. Active DSM reflected here are inputs for the 2025 IRP.

OVERVIEW OF PASSIVE DSM PROGRAMS

Residential Load Management

1. Alabama Power Smart Advantage™ (load optimization and flexibility) – A load optimization program that combines the Residential Time Advantage–Energy Only rate with customized heating/cooling schedules communicated to participants' smart thermostats. Schedules shift energy usage to pre-condition the home during lower cost "economy periods" and allow thermostat setpoints to drift within the customer's comfort band during higher cost "peak periods." This program began as a small event-based pilot in December 2019 and has transitioned to a seasonal demand management program.
2. EV GridWise+ (load optimization and flexibility) – A managed charging program that shifts electric vehicle charging to off-peak periods through optimization strategies. Participants receive incentives for passive or active participation, depending on whether charging is optimized automatically or in response to event signals. While considered a passive program, EV GridWise+ uses Company-provided parameters and integrated technologies to support daily load shaping and seasonal peak reduction.
3. Residential Time Advantage Rates (price signal) – Time Advantage Rates provide pricing signals by time period to encourage customers to shift their usage to lower cost periods. Participants in the Alabama Power Smart Advantage program are not included in the load reduction calculated for being on a Time Advantage rate.
4. Family Dwelling–Demand (price signal) – This rate became available to customers in April 2022 and incorporates a demand charge during winter and summer season peak hours to encourage customers to reduce load during that time.
5. Residential Plug-in Electric Vehicle Rate Rider (price signal) – The rider offers a daily cent/kWh discount on the customer's whole house electric usage between the hours of 9pm and 5am to encourage the customer to charge electric vehicle(s) during off-peak hours.

Residential Energy Efficiency

6. Smart Thermostat Rebate (customer rebates and engagement) – This program provides a rebate for customers who purchase and install qualifying smart thermostats in their homes. Smart thermostats help customers use energy more efficiently and reduce peak usage from their heating and cooling systems. While features vary, many smart thermostats allow customers to manage their energy usage remotely through an app or online platform that can learn from customer behaviors and preferences.
7. Smart Neighborhood Builder Program (beneficial electrification) – This program encourages the installation of heat pumps and electric water heaters in new homes that are constructed to meet a Home Energy Rating System (HERS) Index of 65 or below. A typical home built to the 2006 International Energy Conservation Code (IECC) would be given a HERS rating of 100. Each point of reduction in the HERS index represents a 1 percent increase in energy efficiency. Therefore, a Smart Neighborhood home is at least 35 percent more efficient than a typical home built to the 2006 IECC. Additionally, Smart

Neighborhood homes feature smart home devices, such as smart thermostats and smart light switches, that enable homeowners to monitor and control energy usage from a mobile device.

8. Power Within Your Home (low-to-moderate income/income qualified) – A kit-based program for income-qualified customers that includes a smart thermostat, smart outlet, LED bulbs, weatherization materials, and educational content. The Company provides these bundled measures at no cost to participants, with the goal being to encourage self-installation of energy-saving technologies. The program is designed to support permanent peak load reduction and lower overall energy usage through targeted energy efficiency improvements.
9. Heat Pump Water Heater Program (beneficial electrification) – This program encourages the installation of water heaters that use energy efficient heat pump technology to transfer heat from the surrounding environment to the water.
10. Tankless Water Heater Program (beneficial electrification) – This program encourages the installation of electric tankless water heaters in new construction. These units heat water as needed rather than continually maintaining hot water in a tank.
11. Online Energy Check-Up (customer rebates and engagement) – This program makes an on-line energy audit available to all residential customers, at no cost.
12. Electronic Home Energy Reports (customer rebates and engagement) – A digital behavioral program that provides residential customers with personalized energy usage insights, comparisons to similar homes, and tailored recommendations to reduce consumption. Reports are delivered monthly via email, and customers can access additional tips, usage trends, and progress tracking through an online portal. The program is designed to influence behavior change and promote sustained energy efficiency and peak load reduction over time, at no cost to the customer.

Commercial and Industrial Load Management

13. Business Time Advantage Rates (price signal) – Time Advantage Rates provide pricing signals by time period to encourage customers to shift their usage to lower cost periods.
14. Nighttime Capacity Rate Rider (price signal) – This rider offers billing options for customers whose nighttime capacities exceeds that established during the day due to a significant portion of electric load being operated during nighttime hours.

Commercial and Industrial Energy Efficiency

15. Energy Star Cooking (beneficial electrification) – This program encourages Energy Star cooking equipment in the commercial market.
16. Heat Pump Water Heater Program (beneficial electrification) – This commercial program encourages heat pump water heaters that use energy efficient technology to transfer heat from the surrounding environment to the water.

Transmission and Distribution

17. Distribution Energy Efficiency Program (DEEP) – DEEP operates continuously using capacitors to reduce voltage drop on distribution feeders. The lower voltage upstream of distribution feeders lowers the demand and reduces reactive power requirements.

The projected load reductions associated with the above-described passive DSM programs, as embedded in the load forecasts underlying the 2025 IRP, are shown in Figure A2–2 Winter and Figure A2–2 Summer.

FIGURE A2 - 2 Winter

INTEGRATED RESOURCE PLAN 2025

Projections of Passive Demand-Side Management (DSM) 2025-2044

Gross Peak Load

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PEAK (MW) Winter	15,382	14,656	14,892	15,222	15,400	15,610	15,762	15,830	15,905	15,935
	2035	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
PEAK (MW) Winter	15,961	16,012	16,064	16,134	16,134	16,164	16,186	16,187	16,243	16,293

Passive DSM Impacts

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential Energy Efficiency Programs	(195)	(208)	(221)	(235)	(248)	(262)	(235)	(291)	(306)	(322)
Commercial Energy Efficiency Programs	(25)	(27)	(28)	(30)	(32)	(35)	(38)	(41)	(44)	(49)
Industrial Energy Efficiency Programs	(14)	(15)	(17)	(18)	(20)	(22)	(24)	(27)	(30)	(33)
Peak (MW) Winter	(235)	(250)	(266)	(283)	(301)	(320)	(297)	(359)	(380)	(403)
	2035	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
Residential Energy Efficiency Programs	(338)	(355)	(372)	(390)	(408)	(418)	(418)	(418)	(418)	(418)
Commercial Energy Efficiency Programs	(54)	(59)	(65)	(72)	(79)	(87)	(95)	(105)	(115)	(127)
Industrial Energy Efficiency Programs	(36)	(39)	(43)	(48)	(53)	(58)	(64)	(70)	(77)	(85)
Peak (MW) Winter	(428)	(454)	(481)	(509)	(539)	(562)	(577)	(592)	(610)	(629)

Net Peak Load

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak (MW) Winter	15,147	14,406	14,626	14,939	15,099	15,290	15,465	15,471	15,525	15,532
	2035	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
Peak (MW) Winter	15,533	15,558	15,583	15,625	15,595	15,602	15,609	15,595	15,633	15,664

Passive DSM is alternatives adopted by customers that become inherent in their electric energy use pattern and requirements. Passive DSM is embedded in the Company's load forecast and enumerated in the Integrated Resource Plan.

FIGURE A2 - 2 Summer

INTEGRATED RESOURCE PLAN 2025

Projections of Passive Demand-Side Management (DSM) 2025-2044

Gross Peak Load

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PEAK (MW) Summer	13,150	12,395	12,628	12,949	13,119	13,234	13,296	13,315	13,349	13,344
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
PEAK (MW) Summer	13,321	13,271	13,264	13,268	13,278	13,247	13,193	13,153	13,144	13,155

Passive DSM Impacts

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential Energy Efficiency Programs	(177)	(180)	(183)	(186)	(189)	(192)	(194)	(197)	(200)	(204)
Commercial Energy Efficiency Programs	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)
Industrial Energy Efficiency Programs	(13)	(14)	(16)	(17)	(19)	(21)	(23)	(25)	(27)	(30)
Peak (MW) Summer	(217)	(221)	(225)	(229)	(234)	(239)	(243)	(248)	(254)	(260)
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Residential Energy Efficiency Programs	(207)	(211)	(215)	(219)	(223)	(223)	(223)	(223)	(223)	(223)
Commercial Energy Efficiency Programs	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)
Industrial Energy Efficiency Programs	(33)	(36)	(40)	(44)	(48)	(53)	(58)	(64)	(70)	(77)
Peak (MW) Summer	(266)	(274)	(281)	(289)	(297)	(302)	(307)	(313)	(319)	(326)

Net Peak Load

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak (MW) Summer	12,933	12,174	12,403	12,720	12,885	12,995	13,053	13,067	13,095	13,084
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Peak (MW) Summer	13,055	12,997	12,983	12,979	12,981	12,945	12,886	12,840	12,825	12,829

Passive DSM is alternatives adopted by customers that become inherent in their electric energy use pattern and requirements. Passive DSM is embedded in the Company's load forecast and enumerated in the Integrated Resource Plan.

DSM PILOTS

The Company continues to explore pilot opportunities that can deliver cost-effective load reductions across all three customer classes. These pilots provide critical insights into customer participation, operational feasibility, and long-term DSM potential.

Recent pilot efforts have informed the development of full-scale programs now reflected in the IRP. For example, early testing of thermostat optimization led to the launch of Smart Advantage and Smart Peak Rewards, while pilot testing of electric vehicle charging behavior and telematics integration supported the development of EV GridWise+. Similarly, early outreach and kit testing with income-qualified customers informed the design of the Power Within Your Home program.

Looking ahead, the Company plans to implement pilot phases for additional demand-side programs, including water heater direct load control (WH DLC) and commercial and industrial automated demand response (C&I ADR). These resources are reflected in the available demand-side management tables to acknowledge their potential contribution to future DSM capacity.

Pilot efforts remain an important part of Alabama Power's strategy to identify and scale DSM opportunities that provide customer and system value while maintaining reliability and cost-effectiveness.

Alabama Power's overarching goal as an electric supplier is to deliver cost-effective and reliable service to its customers, along with exceptional customer service. With respect to energy efficiency, the Company supports reasonable building codes and appliance standards that help customers use electricity more efficiently. Alabama Power also encourages energy efficiency practices that are reasonably expected to benefit all customers by helping them better manage their energy usage.

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