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May 21, 2021

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TN PUBLIC UTILITY COMMISSION
DOCKET OFFICE

**21-00061**

Hon. James M. Allison, Chairman
c/o Sharla Dillon
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Petition of Jackson Sustainability Cooperative for a Determination of Exemption or in the alternative for a Certificate of Convenience and Necessity

Dear Chairman Allison:

Jackson Sustainability Cooperative ("JSC") is a nonprofit cooperative established under the Electric G&T Cooperative Act. JSC files an original and 5 copies of the attached Petition, with supporting exhibits, for a Determination of Exemption or in the alternative for a Certificate of Convenience and Necessity to construct and operate a solar facility with battery storage for sharing among its members located on leased property in Madison County, Tennessee (collectively the "Application"). Second, enclosed please find a check in the amount of $25.00 to process this Application.

The Petition seeks to establish JSC as exempt from the control of the public utility commission under the Tennessee Electric G&T Cooperative Act. (T.C.A. §48-69-119) Specifically, JSC proposes to transact business as a nonprofit cooperative that is not characterized as a public utility. The Tennessee legislature provided this exemption based on the perceived need to develop electric power "through renewable, clean and passive sources of electrical energy." (T.C.A. §48-69-102(a)) The statutory scheme concludes with a statement that the Electric G&T Cooperative Act "shall be construed liberally." (T.C.A. §48-69-123(a))

Portions of the Application are being filed under seal. JSC respectfully requests that the Commission treat these portions confidentially because they contain projected capital costs and the names of competing tax equity financing opportunities for the project (Exs. 10 and 11). Public disclosure of this confidential information may harm the ability to negotiate favorable financing arrangements at the lowest reasonable cost. The contract with Northern Reliability, Inc. (Ex. 9) is also marked confidential because it contains information concerning capital costs and projected operating costs. Public disclosure of this information can harm Northern Reliability, Inc.'s ability to negotiate for installation services and equipment purchases in a small market of providers. If this commercially sensitive business and technical information were to be publicly disclosed, it would allow competitors, vendors and other market participants to gain an undue advantage, which may ultimately result in harm to JSC and its members. JSC will make the confidential information available to third parties upon the execution of an appropriate confidentiality and nondisclosure



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agreement.

Thank you for your attention to this matter. Please let me know if you have any questions, or need additional information in support of this application for a prospective ruling on exemption.

Sincerely,

John Beam

John A. Beam, III

Enclosure
cc: Dennis Emberling, CEO

**BEFORE THE TENNESSEE PUBLIC UTILITY COMMISSION**
**NASHVILLE, TENNESSEE**

| | | |
|---|---|---|
| **IN RE: THE APPLICATION OF JACKSON SUSTAINABILITY COOPERATIVE FOR A DETERMINATION OF EXEMPTION AND IN THE ALTERNATIVE, FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY** | ) ) ) ) ) ) | **DOCKET NO. 21-00061** |

**PETITION FOR A SOLAR FACILITY FOR SUPPLEMENTAL ENERGY**

Jackson Sustainability Cooperative ("Jackson Sustainability Cooperative" or "Applicant"), a Tennessee non-profit corporation, through counsel, hereby applies to the Tennessee Utility Commission (the "Commission") to construct and operate a solar facility with battery-energy storage and shared interconnection (the "Facility" or "Solar Facility") located on Roosevelt Parkway in Jackson, Madison County, Tennessee. The Facility will provide supplemental electricity to select Members of Jackson Sustainability Cooperative. The Applicant seeks a determination that it is exempt from the Tennessee Public Utility Commission regulation because, as a non-profit cooperative, it is covered by an express exemption to the definition of "public utility" under T.C.A. 65-4-101(6)(E). If not exempt as an electric cooperative, then the Applicant, based on all the fact and circumstances, seeks a determination that it is not a "public utility" under T.C.A. 65-4-101(6)(A) because it distributes supplemental electrical energy in a manner that is not "affected by and dedicated to the public use.[1]" Alternatively, Jackson Sustainability Cooperative, pursuant to T.C.A. §65-4-201 et. seq., seeks a Certificate of Public Convenience and Necessity authorizing construction of the Facility and connection to its

[1] These factors are discussed in Attorney General Opinion No. 17-25, dated April 10, 2017.

Members.

In spite of the widespread existence of very strong corporate sustainability goals, the shift to renewable energy sources in Tennessee is moving slow. Most electric power generated in Tennessee comes from fossil-fuels, hydro, and nuclear generation. A shared solar facility is one of a very few ways that a small group of local users can acquire clean, renewable, stable, supplemental electricity. The Application is also supported by those Exhibits described as follows:

| | |
|---|---|
| Exhibit 1 | Charter of Jackson Sustainability Cooperative |
| Exhibit 2 | Bylaws of Jackson Sustainability Cooperative |
| Exhibit 3 | Possible Areas to Share Supplemental Energy |
| Exhibit 4 | Member Agreements |
| Exhibit 5 | TVA/JEA Contract and Schedule of Terms and Conditions |
| Exhibit 6 | Integrated Resource Plan of Memphis Light, Gas and Water Authority |
| Exhibit 7 | Integrated Resource Plan of Tennessee Valley Authority |
| Exhibit 8 | Green Connect Program of Tennessee Valley Authority |
| Exhibit 9 | Site Plan for the Facility |
| Confidential Exhibit 10 | Contract with Northern Reliability, Inc. |
| Confidential Exhibit 11 | Capital Cost Estimate |
| Confidential Exhibit 12 | Financing Construction Cost |
| Exhibit 13 | Study on Economic Impact of Facility to Jackson and Madison County, Tennessee |
| Exhibit 14 | Pre-Filed Testimony of Dennis Emberling, President |

WHEREFORE, Jackson Sustainability Cooperative respectfully requests that the Commission allow construction to proceed on the Facility as more specifically described herein.

## General Information

1. The Applicant's full and correct name, business address, and business telephone number are:

Jackson Sustainability Cooperative

Dennis Emberling, President
1031 Greystone Square
Jackson, TN 38305

2. Jackson Sustainability Cooperative is a Tennessee non-profit corporation with its principal place of business at 1031 Greystone Square in Jackson, Tennessee. (see Exhibit 1, Charter) Historically, member owned electric cooperatives work for the sustainable development of the communities they serve. Manufacturing facilities in the Roosevelt Parkway neighborhood in Jackson are heavy users of electricity. Many of these manufacturers have corporate sustainability goals and policies that require use of renewable energy. They cannot economically justify building their own renewable-energy generation facilities in Jackson. Manufacturers can join together to take advantage of economies of scale by constructing and sharing the power a solar facility generates to supplement their demand for electricity and accomplish corporate goals of using renewable energy. Not only will the Facility reduce electricity costs incurred at peak demand, the Facility provides reliable, high-quality, stable power that can withstand major storms and lengthens the life of machinery. Newly installed "smart" meters will monitor precisely monitor electric energy consumption, making significant improvements in energy efficiency and conservation possible.

The municipal utility continue to provide primary usage requirements. The solar facility supplements by meeting the increased demands from time to time for higher amounts of power. In this way, energy from the Facility reduces the level and duration of high demand on the municipal utility, its distribution system, its substations, and TVA's entire system.

The Members of the cooperative also desire to be good corporate citizens of Jackson and contribute to its development, environment, and quality of life. The cooperative's purposes therefore include doing research into various means of conserving energy, bringing Jackson into national prominence with its innovations in solar energy. The cooperative will also bring internships and training programs to Jackson's colleges and high schools, as well as other training to increase and improve the skilled-labor pool in Jackson, Tennessee.

The rights and obligations of the Members who consume supplemental electrical energy from the Facility are defined in the Bylaws of Jackson Sustainability Cooperative. (Exhibit 2, Bylaws). The proposed Solar Facility, at an approximate cost of $67,000,000, includes battery storage, energy-efficiency equipment, and hardware and software to help manage electricity demand.

The initial officers and directors of Jackson Sustainability Cooperative as established in the Charter (Ex. 1) are as follows:

Dennis Emberling, President and Director. Mr. Emberling enjoyed a forty-year career as an internationally-known management consultant. His work has included engagements ranging from small companies to Fortune 100 companies. His innovations in management science and organizational development are in use all over the world, including the United Nations Development Program. He is also an authority on distributed solar, having consulted for solar companies in California for seven years. He is a member of the California Intergovernmental Task Force on Consumer Protection and regularly advises the California Public Utility Commission. He was trained as a mathematician, and he has decades of experience in all aspects of business finance and management.

Dr. Ann Keyl, Director. Dr. Keyl is president of Sacred Heart of Jesus High School in Jackson, Tennessee. Previously, she served as Principle, Center for Research and Education Policy at the University of Memphis. She has an EdD from University of Memphis, an MS in School Counseling from the University of Memphis, and a BA in Education from Lambuth University.

Robert Starr, Secretary and Director. Robert Starr recently retired. Before retiring, he was administrator for the District Attorney General in the 26th Judicial District of Tennessee. He has an MSW from the University of Tennessee at Memphis and a BS from the University of Tennessee at Martin.

Jeff Frieling, Director. Since 1989, Jeff Frieling has served as Vice President and Chief

Information Officer for West Tennessee Healthcare. Mr. Frieling has held positions within the system including Administrative Director of West Tennessee Cancer Center, Administrator of Humboldt General Hospital and Director of Applications in Information Systems. He has degrees in Radiation Therapy, Operations Management, Business Management, a certificate in Healthcare Administration and is a Fellow in the American College of Healthcare Executives. He oversees Information Systems, IT Security, HIM, Bio-Med and the Laboratory Services.

David Shimon, Chief Financial Officer. Mr. Shimon was a founder and former owner of a commercial bank in Maryland, serving on its loan committee and board of directors. He also founded several companies that he guided to success. Currently, he owns and operates a Florida based solar company. Mr. Shimon has expertise in providing opportunities to under-developed empowerment zones in Florida.

Correspondence, documents, and filings regarding this application should be sent as follows:

John A. Beam, III
Equitus Law Alliance, PLLC,
P.O. Box 280240
Nashville, TN 37208
Phone: (615) 251 - 3131
Email: beam@equituslaw.com

**Project Overview**

3. The Applicant proposes to distribute supplemental electricity to its Members from its leased Facility. The Solar Facility is approximately 16.5 MW STC DC output power to be built on approximately 34.27 acres, including approximately 35,098 solar panels of 470 watts each on fixed mounts. Energy is stored using batteries of approximately 46 MWh storage capacity. Distribution of the energy uses controller hardware and software to share supplemental energy among Members. This controller sends the electric energy directly to meters installed at the sites of the Members. The Solar Facility has the ability to generate energy, store energy for distribution to loads, with management over all parts of the system through dynamic control. The system is capable of autonomous operation or operation in parallel with other sources such

as the municipal utility. Jackson Sustainability Cooperative seeks a determination of exemption from regulation as a public utility. Jackson Sustainability Cooperative will comply with the orders of the Commission and Tennessee courts.

4. The meters at the sites of the Members are "smart meters" because which gather more usage information and data (such as by individual circuit) than traditional utility meters which measure energy consumption. Smart meters communicate with the Facility controller to ensure optimum supplemental power distribution to the Member. While the smart meter is connected to both the Facility and the building's electric circuits, it is isolated from the utility's meter so no power from the Solar Facility backflows onto the municipal utility's grid. Members continue to purchase their primary electricity from the municipal power provider.

**Benefits of the Applicant's Model**

5. The Applicant's model provides cost effective, renewable, supplemental electrical energy to local manufacturers and commercial operators. The Facility supports their renewable energy goals and objectives, provides uninterruptible power during outages, as well as assists in controlling energy costs. The Applicant will install underground distribution lines for the power generated from the Facility to participating manufacturers. A map with a diagram of possible areas in which the Applicant can provide supplemental energy to Members is attached as Exhibit 3 (Possible Areas to Share Supplemental Energy).

6. This supplemental source of electrical energy also ensures that risk of interruptions or shortages of electric service currently experienced by local manufacturers is greatly reduced. The Facility designed to withstand extreme storms with storm-hardened components and underground wiring. Power outages currently occur in Jackson, Tennessee due

to animals, weather, trees, vehicles, and construction (Jackson Energy Authority website, Outage Center FAQ). Storms that create major system-wide damage leave customers without power for extended periods of time. Interruptions and outages in electrical power are very costly to manufacturers, who frequently must send employees home as they begin lengthy restart protocols. Currently, some manufacturers use fossil-fuel-based back-up generators to cover outages. Under the Applicant's model, in the event of an outage, the Members switch to using solar energy. The swith is seamless, ensuring no interruptions in service during times of temporary power outages.

7. The solar electric power supplied by the Solar Facility is tightly controlled. The energy output is steady. Voltages stay within a narrow prescribed range, with a steady A.C. frequency close to the rated value, and smooth a voltage-curve waveform. These optimal quality and stability features are expected to increase the life of expensive machinery.

8. The Applicant's model supplies renewable energy that supplements the municipal provider. The amounts charged for electricity by the Applicant will not exceed the rates charged by the municipal provider for monthly usage. (Exhibit 4, Member Agreements) Were the Applicant to charge more than the municipal provider, the Members are free to draw all the electricity they need from the municipal provider.

9. Members continue to draw power from Jackson Energy Authority ("JEA"), the local municipal utility. When their power demand rises above their average level, the Solar Facility will supply additional power seamlessly to the Member. When the grid suffers brownouts or blackouts, the Member continues to draw the power needed to sustain operations from the Applicant.

10. JEA benefits by lowering peak demands experienced by a few of its customers. JEA pays the Tennessee Valley Authority ("TVA") for capacity to supply JEA's peak demand on the system. Meeting peak demand is very expensive for regional suppliers like TVA because they must build and maintain sufficient power-generating capacity to supply the all-time maximum peak demand (with a substantial reserve) for all participating municipal authorities such as JEA. TVA passes these high peak demand costs on to JEA. (Exhibit 5, Schedule of Terms, p. 7) JEA recovers some of this cost from its customers through peak-demand charges. Because of this extra cost for peak demand capacity, the Applicant currently anticipates that lowering the high end of JEA's demand peaks with supplemental electrical power may improve JEA's profitability. Another possible future benefit to JEA is for the Applicant to use its battery storage components to offer storage services to JEA to help with its other peak-demand needs.

**Distribution**

11. The Applicant's model provides a source of renewable supplemental energy for use by 4 to 8 suitable, heavy users of electricity. Jackson Sustainability Cooperative will provide supplemental energy from its Solar Facility to a few manufacturers and commercial facilities located along the West Tennessee Railroad. Additionally, close to the Applicant's site along Dr. F. E. Wright Drive are another 10 commercial facilities. A short distance east are 4 more commercial facilities. There are approximately 38 public and private operators who are prospects for sharing supplemental energy from the Solar Facility. (see Exhibit 3)

12. The Applicant can best benefit Members who have significant peak demand profiles that can be met by the Facility. The initial discussions suggest a very high interest among prospective users who benefit from sharing supplemental renewable energy with

neighbors who are also Members of the Jackson Sustainability Cooperative.

## Renewable Energy Standards and Goals

13. The state of Tennessee currently has no solar-incentive program. Tennessee is in the minority of states in the U.S. who have not established renewable energy targets.

14. Several states that border Tennessee have adopted target standards for their Renewable Energy Portfolios. For example, in 2007, Missouri established a Renewable Electricity Standard which requires that 15% of all consumption comes from renewable energy by 2021. (Mo. Rev. Stat. §393.1020 to 1050) In 2007, North Carolina similarly established a Renewable Energy and Energy Efficiency Portfolio Standard with a requirement that 12.5% of all energy consumption comes from renewable energy sources by 2021. (N.C. Gen Stat. §62-133/8) These statutory standards are generally measured by the percentage of renewable retail electric energy sales to all retail electric energy sales.

In 2020, Virginia established a Renewable Portfolio Standard of 100% renewable energy by 2045 (or by 2050 depending on the phase of public utilities). (VA Code Ann. §10.1-603.24.25; §10.1-1329; §10.1-1330; §56-576 and 585) Prior to 2020, Virginia had a voluntary renewable goal of 15% of all energy consumption by 2024. The new law increases in phases from 14% in 2025, 30% by 2030, and so on until 100% by 2050. In 2014, South Carolina established a Voluntary Renewable Portfolio Standard that targets a 2% requirement for renewable energy by 2021. (SC Code 58-39-110 et seq.) South Carolina and Virginia public policy demonstrate how small steps in the shift of consumption can lead to exponential environmental benefits.

15. The Applicant has reviewed the Integrated Resource Plan of Memphis Light, Gas

and Water Authority ("MLGW") filed May 29, 2020 because of its close proximity to Jackson, Tennessee. A copy of excerpted pages is attached as Exhibit 5. MLGW forecasts average loads changing over the next ten years by between -6.9% and +11.1%, for an average of 2.1%, with peak demand changing over the next 10 years by between -7.1% and +17.1%, for an average of 5% per year (Ex. 6, Appdx, p. 18).

16. Remarkably, MLGW forecasts increases in energy prices over the next 5.5 years of between 40% and 125% (Ex. 6, Appdx, p. 26). One of the cost drivers is the lost power and added costs as electricity goes from the generation site to the competitive transmission developers to the transmission owners to the power marketers/brokers to the utilities to the end-user customers (Ex. 6, Part I, p. 6).

17. MLGW presented the lowest cost scenario for consumers as using "up to 75% renewable energy and cut carbon pollution by 50% compared to TVA levels, resulting in better public health, cleaner air, and cleaner water." (Ex. 6, p. 10).

18. Jackson Energy Authority does not generate electricity. JEA buys power from the Tennessee Valley Authority under the terms of its present contract with TVA. (Exhibit 5) JEA is not required to prepare an Integrated Resource Plan. However, conclusions on general market conditions drawn by MLGW are very likely similar to the market conditions in Jackson, Tennessee.

19. In 2019, TVA prepared an Integrated Resource Plan. A copy is attached as Exhibit 7. TVA has the stated corporate goal to add between 1,500 and 8,000 MW of solar power generation by 2028, and up to 14,000 MW by 2038 conditioned on increasing load growth. (Ex. 7, p. ES-4). A second goal for TVA is to evaluate battery storage to gain

operational experience. (Ex. 7, p. ES-5). The Applicant's Facility is consistent with TVA's goals.

20. In its IRP, TVA identifies the advantages of local, distributed energy over energy transmitted over long distances and managed by multiple intermediaries (Ex. 7, pp. ES-7, 1-4, 2-2, 5-11). TVA recognizes the importance of moving toward implementation of programs that provide for flexible electricity generation for customers. (Ex. 7, p. ES-1) As TVA replaces expiring or retiring capacity, solar expansion plays a substantial role in all future models for the generation of electricity. (Ex. 7, p. ES-2)

21. TVA had a Green Connect Program that allows customers to sell power from qualified facilities to TVA. (Ex. 8, attached) The stated purpose of the former program was to help consumers support renewable energy generated within the Tennessee valley. The program ended on December 31, 2019.

22. Kellogg is a local manufacturer in Jackson, Tennessee. Kellogg has a corporate goal to achieve 100% renewable energy in its operations by 2050. Toyota is a local manufacturer. Toyota has the same corporate goal as Kellogg.

**Establishment of the Facility**

23. Construction is anticipated to begin in 2021. Operations are expected to begin as early as February or March of 2022. The Applicant will lease its generation and deliver equipment from Community Development Enterprises - Jackson I ("CDE"). CDE will be a Patron of the Applicant to supply needed capital. (see Exhibit 2, Bylaws, Section 9.2)

24. CDE was formed as a joint venture on September 3, 2020 to investigate the feasibility of developing a Solar Facility to help Members who have common goals share the

energy from the Facility as a cooperative. The venture participants include E A Solar, LLC, a Delaware limited liability company, Hunt Solar, LLC, a Delaware limited liability company, and SynEnergy, Inc., a Virginia corporation. As a collaborative effort, CDE's collective participants have the managerial, technical, and financial abilities to design, procure equipment, construct, and lease renewable, electrical-energy equipment to the Applicant to serve its few industrial and/or institutional Members. CDE engaged Northern Reliability, Inc, an expert in the design, construction, and operation of solar facilities as the prime contractor for the development of the Applicant's Solar Facility (see Paragraphs 27 and 29 below). Tax-equity financing and financial ability are discussed in Paragraph 32 below.

25. The Facility is located on 34.27 acres of land situated on Roosevelt Parkway, just west of Dr. F. E. Wright Drive, in Jackson, Tennessee. The GPS coordinates of the approximate center of the Facility are: 35.6357 N; 88.7921 W. The Applicant's Site has unshaded, south-facing exposure to the sun and easy service access from two points on Roosevelt Parkway. It is not in a flood zone and does not include wetlands. A map showing the layout of the Facility and a schematic of the equipment used in the systems is attached as Exhibit 9 (Site Plan).

26. All required environmental studies have been completed and approvals received. First was permission to clear the site from U. S. Fish and Wildlife, finding that there are no protected plants, habitats, or animals on the site and that it is not a wetland. Second was similar permission from the Tennessee Wildlife Resources Agency. Third was approval from the Tennessee Department of Environment and Conservation (TDEC) division of Natural History/Heritage, finding that there were no rare or endangered plant or animal species, ecologically significant sites, or conservation-managed areas within the site. Fourth was approval

to clear the site from the TDEC division of Cultural History, stating that there was no record of anything of archaeological significance on the site. Fifth was a general permit for bank armoring and vegetative stabilization (ARAP) from TDEC's Division of Water Resources. Sixth was a Construction Storm Water Permit (NPDES) from TDEC.

27. L. I. Smith and Associates, Inc. provided civil engineering and site design. L. I. Smith and Associates, Inc. submitted the Facility design to the Planning Commission for the City of Jackson for approval. These submissions included a hydrologic wetlands and stream determination study, which found that there are no wetlands on the site; a stormwater drainage plan; a Vegetation Impact Evaluation with tree inventory to determine requirements for preparing the site; an Erosion and Sedimentation Control Plan; a site grading plan; a boundary survey; and a site plan showing site barriers and buffer zones as well as the location of equipment on the site.

26. An emergency 911 street address has not been assigned to the Facility at this time. The Applicant will notify the Commission of the emergency 911 street address when it is received. Because Jackson, Tennessee experiences high winds, the solar panels selected will withstand high winds. The battery systems will be storm-hardened, and all wiring underground.

27. Northern Reliability, Inc., a Vermont corporation, will serve as the prime contractor and provide engineering and construction field services to design, engineer, procure equipment and construct the Facility. iSun Inc., a fifty-year old solar-development firm, as well as a local general contractor and electrical contractor hired by the Applicant, will assist Northern Relaibility (Confidential Exhibit 10, contract). Northern Reliability, Inc. was selected from among many qualified firms because of their experience in building over 1,000 similar solar projects all over the world.

28. The Applicant and/or CDE will secure all applicable federal, state, and local permits. A Special Use Permit from the City of Jackson is required for construction of the proposed Facility on the Site. Approval from the City of Jackson will be filed on request. Construction requires a building permit and an electrical permit.

29. After installation is completed on the Site and wired to the smart meters used by Members, Northern Reliability, Inc. will commission and test the Facility and entire Jackson system prior to operation.

## Financing

30. The capital cost estimate for procurement and construction of the Solar Facility is approximately $67,000,000. (Confidential Exhibit 11) This estimate includes design and field engineering, procurement of equipment, installation of all major equipment, and construction of the Solar Facility and components for Members to share supplemental electrical energy.

31. Private financing will fund construction of the Solar Facility. The Applicant will lease the equipment and appendages from CDE. The small group of cooperative Members will not share in the risk of default.

32. Numerous funders have made oral commitments to finance the Facility. The funders under consideration are major tax-equity investors. They are listed on Confidential Exhibit 12, attached. Federal tax credits and accelerated depreciation benefits factor into funding the capital cost estimate for construction of the Solar Facility and related equipment.

## Community Impact

33. Jackson, Tennessee is a small city of about 67,000 in southwest Tennessee. In 2009, the City of Jackson established a Community Redevelopment Agency (CRA) to work with

private entities to form public-private partnerships to build and restore Jackson. (Jackson Revitalization Strategy/Community Redevelopment Act Workable Program, February, 2009). Several of the officers and directors of the Applicant have a long working relationship with CRA.

34. The general contractors and electrical contractor selected will employ local citizens to promote economic development in Jackson, Tennessee. Components and services will be purchased from Tennessee providers who provide the required functionality and are cost competitive.

35. Construction and operation of the Solar Facility has a significant economic impact and benefit to Jackson and Madison County. Specifically, the economic impact is $212,000,000.00 over 10 years plus another $14,000,000.00 in new tax receipts (Exhibit 13, SynEnergy Economic Impact Study). It also provides the full-time-equivalent of 511 new jobs in 2021, and 23 permanent jobs thereafter, growing to 28 by 2030. (Id.)

36. The Applicant's model will make Jackson, Tennessee widely known as a renewable energy leader, and attract new business and economic development to the area. The Applicant will help local schools and colleges introduce new training, career programs, and internships in the solar and storage fields, leading to increased job opportunities for the entire community.

## Conclusion and Summary

37. The Applicant's Solar Facility will bring supplemental clean energy to a small group of manufacturers and commercial operators to accomplish their renewable energy goals, improve the quality and stability of their electrical energy, and assist in controlling the peak demand cost of electrical energy. See Pre-Filed Testimony of Dennis Emberling, President.

(Exhibit 14)

38. Operation of the Solar Facility will have no emission or pollutants because the solar generation source is 100% renewable energy.

39. Jackson Sustainability Cooperative intends to work cooperatively with JEA and TVA to further their stated goals for renewable energy and local distribution of energy in the future. The Applicant and CDE hope that this Facility will lead to opportunities to partner with JEA and TVA in the future as they continue to move into solar energy and battery storage fields.

40. The Applicant's Facility is consistent with and promotes the public policies of setting and accomplishing Renewable Energy Standards for the future. The Facility will diversify power generation resources while providing greater energy stability and security through the use of the sun, an indigenous energy resource in Tennessee.

41. As previously discussed herein, the benefits to Members who share in supplemental electrical energy is based on the following:

a. Improving the resiliency and reliability of electric service to key manufacturing employers in Jackson, Tennessee. The Applicant's Facility for supplemental renewable energy is a modern solution that allows participants to continue using local energy from the municipal provider while having a local renewable generation and storage facility that reduces the risk of outages with real savings to the participants who have expensive restart-protocols.

b. Assisting major manufacturing facilities in Jackson in making substantial progress toward their stated corporate goals by switching some of their peak energy consumption from fossil-fuel based to fully clean, green, renewable energy from solar sources stored in lithium batteries.

c. Facilitating energy conservation through smart meter technology that allows customers to receive solar power and to prioritize and monitor their electrical usage down to the individual circuit level, giving them previously unavailable information and enabling them to increase efficiency in their facilities.

d. Reducing manufacturers' maintenance and replacement expenses for their expensive machinery as a result of improved power quality and minimizing outagers such as brownouts and blackouts.

e. Enabling Members to acquire supplemental energy to operate with better efficiency in the hopes that they choose Jackson, Tennessee as the place to expand their business operations in the future.

42. If the Applicant's model is approved for construction and operation, the Applicant will abide by the rules, regulations, and orders applicable to its operation as a non-profit electric cooperative under Tennessee law.

WHEREFORE, Jackson Sustainability Cooperative respectfully requests a determination that it is exempt from regulation as a "public utility" by the Public Utility Commission because it is a "cooperative organization ... not organized or doing business for profit." T.C.A. 65-4-101(6)(E). If not exempt as an electric cooperative, then the Applicant, based on all the facts and circumstances, seeks a determination that it is not a "public utility" under T.C.A. 65-4-101(6)(A) because it distributes supplemental electrical energy in a manner that is not "affected by and dedicated to the public use." Alternatively, the Applicant, pursuant to T.C.A. §65-4-201 et. seq., seeks a Certificate of Public Convenience and Necessity authorizing construction of the Facility pursuant to T.C.A. §65-4-204 et. seq. as specifically described above.

Respectfully submitted this 21st day of May, 2021.

John Bean

John A. Beam, III (Bar No. 11796)
Equitus Law Alliance, PLLC,
P.O. Box 280240

Nashville, TN 37208
Phone: (615) 251 - 3131
Email: beam@equituslaw.com

Attorney for Jackson Sustainability Cooperative

CERTIFICATE OF SERVICE

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General Counsel
Jackson Energy Authority
351 Martin Luther King Jr. Drive
Jackson, Tennessee 38301

Monte Cooper, PE
Sr. Vice President, Electric Division
Jackson Energy Authority
351 Martin Luther King Jr. Drive
Jackson, Tennessee 38301

VERIFICATION OF PETITION

STATE OF TENNESSEE )
COUNTY OF MADISON )

Before me, the undersigned authority, a notary public in and for said State and County, personally appeared Dennis Emberling, who, being duly sworn according to law, deposes and states under penalties of perjury that he is the President of Jackson Sustainability Cooperative, that he is authorized to make this Affidavit on its behalf, that he is over the age of twenty-one (21) and under no disability and that the facts and averments set forth in the foregoing Petition are true upon his personal knowledge or, where indicated in the Petition, upon information and belief. The Applicant will abide by federal and state laws and regulations as well as this Commission's orders in constructing and operating a solar facility which provides supplemental electrical power to participating Members in Jackson, Tennessee.

Jackson Sustainability Cooperative

By: Dennis Emberling
Dennis Emberling, President

Sworn to and subscribed before me, this 20th day of May, 2021.

Notary Public

EARNEST ANDERSON
STATE OF TENNESSEE NOTARY PUBLIC
WILLIAMSON COUNTY
My Commission Expires July 5, 2022

My Commission Expires: July 5 2022

# EXHIBIT 1

Tre Hargett
Secretary of State

**Division of Business Services**
**Department of State**
State of Tennessee
312 Rosa L. Parks AVE, 6th FL
Nashville, TN 37243-1102

ACKSON SUSTAINABILITY COOPERATIVE
031 GREYSTONE SQ
ACKSON, TN 38305-3581

May 14, 2021

## Filing Acknowledgment

lease review the filing information below and notify our office immediately of any discrepancies.

| | | | |
|---|---|---|---|
| **OS Control # :** | **001200202** | Formation Locale: | TENNESSEE |
| iling Type: | Nonprofit Corporation - Domestic | Date Formed: | 05/14/2021 |
| iling Date: | 05/14/2021 8:34 AM | Fiscal Year Close: | 12 |
| tatus: | Active | Annual Report Due: | 04/01/2022 |
| uration Term: | Perpetual | Image # : | B1034-0020 |
| ublic/Mutual Benefit: | Mutual | | |
| usiness County: | MADISON COUNTY | | |

**Document Receipt**

| | | | |
|---|---|---|---|
| eceipt # : 006363414 | | Filing Fee: | $100.00 |
| a, nt-Check/MO - EQUITUS LAW ALLIANCE, PLLC, NASHVILLE, TN | | | $100.00 |

**egistered Agent Address:**
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1031 GREYSTONE SQ
JACKSON, TN 38305-3581

ongratulations on the successful filing of your **Charter** for **JACKSON SUSTAINABILITY COOPERATIVE** in the tate of Tennessee which is effective on the date shown above. You must also file this document in the office of the egister of Deeds in the county where the entity has its principal office if such principal office is in Tennessee. Please sit the Tennessee Department of Revenue website (www.tn.gov/revenue) to determine your online tax registration quirements. If you need to obtain a Certificate of Existence for this entity, you can request, pay for, and receive it om our website.

ou must file an Annual Report with this office on or before the Annual Report Due Date noted above and maintain a egistered Office and Registered Agent. Failure to do so will subject the business to Administrative issolution/Revocation.

Tre Hargett
Tre Hargett
Secretary of State

rocessed By: Alex Maxfield

FILED

# CHARTER
# OF
# JACKSON SUSTAINABILITY COOPERATIVE

The undersigned person, under the Tennessee Nonprofit Corporation Act, adopts the following Charter for JACKSON SUSTAINABILITY COOPERATIVE.

1. The name of the Corporation is JACKSON SUSTAINABILITY COOPERATIVE.

2. The purpose or purposes for which this Corporation is formed are:

   (a) To assist its members in sharing supplemental electrical energy from renewable sources while contributing to the redevelopment of the Roosevelt Parkway neighborhood in Jackson, Tennessee;

   (b) To promote corporate goals for renewable energy where the Members cannot economically justify building, maintaining and operating their own renewable solar energy facilities;

   (c) To assist its members in the efficient and economical use of energy;

   (d) To use smart meter technology to allow members who share a solar facility to directly connect to the solar facility and share supplemental energy with other members;

   (e) To engage in research and to promote and develop energy conservation and sources and methods of conserving, producing, converting, and delivering energy;

   (f) To accomplish improved energy efficiency by acquiring the ability to monitor electricity usage by individual circuits;

   (g) To promote energy conservation through research into methods of conserving, producing, converting, and delivering energy;

   (h) To provide programs and training in solar energy for members by enhancing labor skills, and providing educational enrichment and curricula for schools and colleges.

   (i) To purchase, lease as lessee, and in any manner acquire the use of solar equipment, machines, supplies, and systems necessary or useful for furnishing supplemental electrical energy to its members in carrying out the purposes of the Corporation;

   (j) To acquire the use of, to the extent permitted by law, the franchises, rights, privileges, licenses, rights-of-way and easements necessary or useful for furnishing supplemental electrical energy to its members in carrying out the purposes of the Corporation;

   (k) To purchase, lease as lessee, or in any other manner acquire or dispose of any and all real and personal property or any interest therein necessary or useful for furnishing



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supplemental electrical energy to its members in carrying out the purposes of the Corporation;

(l) To borrow money, to make and issue bonds, notes and other evidences of indebtedness, secured or unsecured, and used in payment for property acquired, or for any of the other purposes of the Corporation, to secure the payment by deeds of trust upon, or by the pledge of any other lien upon, any or all of the property, rights, privileges or permits of the Corporation, wheresoever situated, acquired or to be acquired;

(m) To do and perform, either for itself or its members, any and all acts and things, and to have and exercise any and all of the foregoing purposes or as may be permitted by the Acts under which the Corporation is formed, for any lawful act or activity necessary or convenient to effect the foregoing purposes, including, but not limited to, the exercise of all powers granted to electric membership corporations as set forth in the Tennessee Electric G&T Cooperative Act of 2009, T.C.A. § 48-69-101 *et seq.*, as amended from time to time.

3. (a) The Corporation is a not for profit corporation organized for the benefit of its members pursuant to the provisions of the Tennessee Electric G&T Cooperative Act of 2009, T.C.A. § 48-69-101 *et seq.*

(b) The Corporation is a mutual benefit corporation.

(c) Membership and membership rights, privileges and obligations shall be as prescribed in the Bylaws of the Corporation.

(d) The private property of the Members of the Corporation shall be exempt from execution for the debts of the Corporation.

4. The period of duration of this Corporation is perpetual.

5. The name and complete address of the Corporation's registered agent is John A. Beam, III, P.O. Box 280240, 709 Taylor Street, Nashville, Davidson County, Tennessee 37208.

6. The name and address of the incorporator is: John A. Beam, III, P.O. Box 280240, Nashville, Davidson County, Tennessee 37228-0240.

7. The address of the Corporation's principal office is 1031 Greystone Square, Jackson, Madison County, Tennessee 38305.

8. The affairs of the Corporation shall be managed by a Board of Directors. The number of the Directors of the Corporation and the method of their election shall be established in the Bylaws. The number of initial, organizational Directors of this Corporation shall be five persons. The five organizational Directors shall serve until the solar facility is tested, commissioned, and certified, and then at the next annual meeting of the members the Directors will be elected under the process established in the Bylaws. The names and addresses of the organizational Directors who shall

manage the affairs and business of the Corporation until the election of the Directors after the solar facility is operational are listed as follows:

(a) Dr. Ann Keyl, 445 Walnut Street, Jackson, TN 38305
(b) Mr. Robert Starr, 140 Sunnyvalley Drive, Jackson, TN 38305
(c) Mr. Jeff Frieling, 161 Shadow Ridge Drive, Jackson, TN 38305
(d) Dennis Emberling, 5548 Trousdale Drive, Brentwood, TN 37027
(e) David Shimon, 19840 W. Dixie Hwy, Unit #3311, Miami, FL 33180

9. The Corporation may be dissolved under provision established in the Bylaws.

10. Directors shall not have personal liability to the Corporation for monetary damages for a breach of fiduciary duty as a Director. This limitation shall not eliminate or limit the liability of the director for any breach of a director's duty of loyalty to the corporation or for any acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law.

11. Except as specifically limited in Section 48-58-502 of the Tennessee Nonprofit Corporation Act, this corporation shall indemnify against liability incurred in a proceeding by any individual made a party to the proceeding because he or she was or is a director or officer of this Corporation if the person conducted himself or herself in good faith and reasonably believed that:

(a) In the case of conduct in his or her official capacity with the Corporation, the conduct was in the Corporation's best interest;

(b) In all other cases, the conduct was at least not opposed to the best interest of the Corporation;

(c) In the case of any criminal proceeding the individual had no reasonable cause to believe the conduct was unlawful; and

(d) Conduct with respect to an employee benefit plan for a purpose reasonably believed to be in the interest of the participants and beneficiaries of the plan and the conduct was at least not opposed to their best interest.

12. The document is to be effective upon filing by the Secretary of State.

Dated this 14th day of May, 2021.

John A. Beam

John A. Beam, III, Incorporator

# EXHIBIT 2

# BYLAWS OF
# JACKSON SUSTAINABILITY COOPERATIVE

*Preamble*

Jackson Sustainability Cooperative seeks to enable a small group of manufacturers with facilities in the Roosevelt Parkway neighborhood of Jackson, Tennessee to share supplemental electrical energy from renewable sources that helps them mitigate the cost of peak demand energy and period power outages. Members who share this supplemental energy share the common goal of moving to renewable energy, while contributing to the redevelopment of this area of Jackson. A shared solar facility allows Members to make progress toward corporate goals for renewable energy where they cannot economically justify building, maintaining and operating their own renewable energy generation facilities. New smart meter technology allows members to directly connect to the solar facility and share supplemental energy with other like-minded manufacturers and commercial operators. On the plant side of the smart meter, the Members gain improved energy efficiency by acquiring the ability to monitor electricity usage by individual circuits. Jackson Sustainability Cooperative (the "Cooperative") also promotes and develops energy conservation through research into methods of conserving, producing, converting, and delivering energy. Jackson Sustainability Cooperative will give the local labor force training in solar energy. Training programs will be expanded to the schools and colleges in the future.

## ARTICLE I
## GENERAL PROVISIONS

**Section 1.1. Purposes and Aims of Corporation.** This Corporation was formed and exists to do and perform, either for itself or its Members, any and all acts and things, and to have and exercise any and all of the powers granted to electric membership corporations as may be permitted by the Tennessee Electric G&T Cooperative Act of 2009 and by T.C.A. § 48-69-101 *et seq*., as amended from time to time, for any lawful act or activity, including, but not limited to, the following:

1. To assist its members in sharing supplemental electrical energy from renewable sources while contributing to the redevelopment of the Roosevelt Parkway neighborhood in Jackson, Tennessee;

2. To help achieve corporate goals for sustainability where the Members cannot economically justify building, maintaining and operating their own renewable energy solar facilities;

3. To conserve energy by acquiring the ability to monitor electricity usage by individual circuits;

4. To assist its Members in the efficient and economical use of energy;

5. To use smart meter technology to allow Members who share a solar facility to directly connect to the solar facility and share supplemental energy with other Members;

6. To avoid costs caused by grid outages by gaining access to solar power, without

having to resort to dangerous and toxic fossil-fuel backup generators;

7. To increase the reliability and lengthen the life span of machinery by acquiring higher quality power in terms of voltage and frequency regulation, particularly during periods of high demand;

8. To improve environmental quality in and around Jackson, Tennessee;

9. To engage in research and to promote and develop energy conservation and sources and methods of conserving, producing, converting, and delivering energy;

10. To provide programs, training, and internships in solar energy for Members by enhancing labor skills, and providing educational enrichment and curricula for schools and colleges.

11. To expand and improve Jackson's pool of skilled-labor, increasing the skilled workforce that will enable members' businesses to expand in Jackson, providing more jobs to the Jackson community;

12. To increase the resiliency and redundancy of Jackson's electrical supply by providing supplementary sources of energy;

13. To reduce stresses on the Tennessee Valley Authority's grid and the Jackson Energy Authority distribution system by relieving peak demand, without capital cost to Jackson;

14. To purchase, lease as lessee, and in any manner acquire the use of solar equipment, machines, supplies, and systems necessary or useful for furnishing supplemental electrical energy to its members in carrying out the purposes of the Corporation;

15. To acquire the use of, to the extent permitted by law, the franchises, rights, privileges, licenses, rights-of-way and easements necessary or useful for furnishing supplemental electrical energy to its members in carrying out the purposes of the Corporation;

16. To purchase, lease as lessee, or in any other manner acquire or dispose of any and all real and personal property or any interest therein necessary or useful for furnishing supplemental electrical energy to its members in carrying out the purposes of the Corporation; and,

17. To borrow money, to make and issue bonds, notes and other evidences of indebtedness, secured or unsecured, and used in payment for property acquired, or for any of the other purposes of the Corporation, to secure the payment by deeds of trust upon, or by the pledge of any other lien upon, any or all of the property, rights, privileges or permits of the Corporation, wheresoever situated, acquired or to be acquired.

**Section 1.2. Defined Terms**. These Bylaws define certain words, phrases, and terms ("Defined Terms"). In general, Defined Terms are: (1) defined in a full sentence or part of a sentence; (2) capitalized, underlined, and enclosed within quotation marks when defined; (3) enclosed within parenthesis when defined in part of a sentence; and (4) capitalized when otherwise used in these Bylaws. Except as otherwise provided in these Bylaws and subject to the context requiring otherwise, Defined Terms have the meaning specified in the appropriate Bylaw.

**Section 1.3. Law and Charter**. These Bylaws are subject to Law (defined below) and the Charter filed with the Tennessee Secretary of State ("Charter"). If, and to the extent that, a Bylaw conflicts with Law or the Charter, then the Law or Charter control. "Law" includes applicable (1) local, state, and federal statutes and regulations, and (2) legally binding contracts enforceable by or against the Cooperative, including the Member Agreement.

**Section 1.4. Validity of Electronic Signatures**. To the extent that Member Agreement or any other document between the Cooperative and the Members or Directors, is completed or transmitted by electronic means, the Member or Director agrees to be bound by federal and state laws and regulations governing the validity of such electronic signatures, and agrees that any such electronic transmission to or from the Member or Director satisfies any requirements imposed by the law that a document, notice, minutes or other communication be in writing. The Member or Director agrees that any document sent electronically to the Member or Director or former Member at the Member's last known electronic address is considered received on the date sent by the Cooperative.

## ARTICLE II
## MEMBERSHIP

**Section 2.1. Eligibility Requirements**. The "Cooperative Service" is supplemental electric energy provided by the Cooperative. An "Entity" includes a domestic or foreign business or nonprofit corporation, limited liability company, or any agency or division of government. An Entity becomes a conditional member of the Cooperative if it signs a Conditional Member Agreement. The Cooperative will analyze the energy profile and energy demands of the conditional Member to see if the conditional Member's electricity needs are a suitable fit for the Cooperative Service. Qualifying conditional Members are invited to become full Members who receive the Cooperative Service after they sign a Full Member Agreement (such person being a "Member" and the Member being in a "Membership"). An applicant is eligible for conditional Membership if its plant and facility

1. annually requires or is expected to annually require at least 100,000 kilowatt-hours (kWh) of electric energy; and,

2. uses electric energy on a demand curve consistent with the Cooperative's requirements.

**Section 2.2. Cooperative Membership**. These Bylaws are a contract between the Cooperative and a Member. If a Member fails to comply with the Bylaws, the Conditional Member Agreement, or the Full Member Agreement, the Cooperative may suspend or terminate the Member or the Cooperative Service provided to the Member.

1. Each Member agrees to:

   a. Comply with the Bylaws;

   b. Comply with the Member Agreement it signs;

   c. Comply with any rules established and approved to manage the sharing of supplemental energy;

   d. Pay dues of $10.00 per year;

   e. Pay for the Cooperative Service used at prices, rates, or amounts established in the Member Agreement;

   f. Pay for Cooperative Service during municipal outages within the priority guidelines agreed to between the Cooperative and Member from time to time;

   g. provide and maintain a current mailing address and telephone number with the Cooperative.

2. The Member Agreements will be on forms provided by the Cooperative. The Conditional Member Agreement will require a review of the applicant's electric energy demand curve. There is no connection fee or deposit. The Full Member Agreement will provide for sharing supplemental energy with other Members.

3. Unless the Member Agreement provides otherwise, if the Cooperative Service is not paid for within 30 days, the outstanding amount owed to the Cooperative bears a late fee at the monthly periodic rate of 1.5% (18% per annum) until paid in full.

4. Member Premises Equipment ("MPE") consists of any equipment, device or apparatus that is physically located on a Member's property that was installed by the Member and maintained by the Member. Cooperative Equipment consists of any equipment, device or apparatus that was installed by the Cooperative, including the smart meter and other equipment used to transfer, monitor and share electric energy provided by the Cooperative to allow the Member to access the supplemental energy provided by the Cooperative ("Cooperative Equipment"). In no event shall the responsibility of the Cooperative extend to the MPE. The Cooperative shall repair malfunctioning of Cooperative Equipment or any error occurring in the Cooperative's billing procedures. The Member shall repair malfunctioning MPE.

**Section 2.3. Acceptance into Full Membership**. Upon complying with the requirements set forth in Section 2.2, an applicant will be offered a Full Membership Agreement, and upon signing is eligible to receive Cooperative Service provided by the Cooperative. If the Member is unable to abide by the Full Member Agreement and these Bylaws, then the person's Membership may be suspended or terminated by the Cooperative.

**Section 2.4 Provision of Cooperative Service**. The Cooperative shall use reasonable efforts to furnish its Members with adequate and dependable Cooperative Service. However, the Cooperative does not exist to replace the existing municipal electric service except temporarily in the event of municipal electric service outages. In case of emergency, or as requested by government or emergency officials or representatives, the Cooperative may interrupt the provision of Cooperative Service to Members.

Each Member shall pay for such purchases when they become due and payable in accordance with the Full Member Agreement and rate classifications and rate schedules established by the Cooperative. A Member may have more than one service connection from the Cooperative. The Cooperative's accounting procedures will reflect both connections.

**Section 2.5. Wiring of Premises; Responsibility for Wiring, Meter Tampering or Bypassing and for Damage to Cooperative Equipment**. Each Member shall cause all premises receiving electric service pursuant to its Membership Agreement to become and to remain wired in accordance with the specifications of the Tennessee Fire Insurance Underwriters Association, the National Electrical Code, any applicable state code or local government ordinances, requirements of the local municipal power authority, and requirements of the Cooperative. The Cooperative will provide the Cooperative Service at a location agreed to with the Member using Cooperative Equipment. A Member shall: (1) protect Cooperative Equipment; and (2) maintain any protective device or procedure to protect the connection. A Member shall not tamper with, alter, interfere with, damage, or impair Cooperative Equipment.

**Section 2.6. Member Arbitration, Indemnification, and Liability**. Whenever requested by the Cooperative, a Member shall:

1. Submit a claim or dispute between the Member and the Cooperative regarding the Member Agreement or the Cooperative's provision of Cooperative Service, or the Member's use of a Cooperative Service to mediation and arbitration and shall comply with an arbitration award according to the rules and procedures prescribed by the operative rules of the American Arbitration Association. A demand for arbitration shall be made within a reasonable time after the claim, dispute or other matter in question has arisen.

2. Indemnify the Cooperative for, and hold the Cooperative harmless from, liabilities, damages, costs, or expenses, including reasonable attorney fees and legal expenses, incurred by the Cooperative, or its directors, officers, employees, agents, or representatives (collectively, "Cooperative Officials"), and caused by the Member's negligence, gross negligence, or willful misconduct, or by the unsafe or defective condition of a location occupied by the Member that is not the fault of the Cooperative.

In general, a Member is not liable to third parties for the Cooperative's acts, debts, liabilities, or obligations solely because of Membership in the Cooperative. A Member may become liable to the Cooperative as provided in the Full Member Agreement or Bylaws or as otherwise agreed to by the Cooperative and the Member.

**Section 2.7. Access**. Each Member shall make available to the Cooperative a suitable site, as determined by the Cooperative, whereon to place the Cooperative's physical equipment for the furnishing and metering of Cooperative Service and shall permit the Cooperative's authorized employees, agents and independent contractors to have access thereto safely and without interference from any hostile source for inspection, maintenance, replacement, relocation, repair or disconnection of such facilities at all reasonable times, and at any time during an emergency. As part of the consideration for such service, each Member shall be the Cooperative's bailee of such facilities and shall accordingly desist from interfering with, impairing the operation of or causing damage to such facilities, and shall use its best efforts to prevent others from so doing. The Cooperative will generally provide email notice of its need to enter the Member property for an inspection and/or repair of the Cooperative Equipment.

**Section 2.8. Member to Grant Property Rights to Cooperative**. The Member shall grant the Cooperative in the Full Member Agreement or other agreement a right-of-way, license or other grant or interest in Member property, under such lands owned, leased, mortgaged, by the Member to connect the Cooperative Service or for a Cooperative Purpose (defined below). In the event Member has a mortgage or lien on a property, the Member shall not use the mortgage or lien as a reason to object to the grant of property rights pursuant to this section. A "Cooperative Purpose" is: (1) installing, constructing, inspecting, monitoring, operating, repairing, maintaining, removing, relocating, upgrading, or replacing Cooperative Equipment; (2) clearing, trimming, removing, or managing any trees, bushes, brush, or other vegetation to run wire underground to the Member facility; (3) providing a Cooperative Service to the Member or another Member; (4) monitoring, measuring, or maintaining a Cooperative Service provided to a Member; (5) authorizing, permitting, satisfying, or facilitating an obligation incurred, or right granted, by the Cooperative regarding use of Cooperative Equipment; or (6) safely, reliably, and efficiently providing a Cooperative Service to the Member.

**Section 2.9. Energy Conservation**. Member and Cooperative shall work together to enhance energy conservation, to more efficiently utilize electric energy, and to conduct energy usage research.

**Section 2.10 Statement of Nondiscrimination**. The Cooperative does not discriminate on the basis of race, color, national origin, sex, religion, age, disability, or other protected class. The Cooperative encourages persons who believe they have been improperly discriminated against to contact the President. Written discrimination complaints must be filed not later than 180 days from the date of the alleged discrimination.

## ARTICLE III
## MEMBERSHIP SUSPENSION AND TERMINATION

**Section 3.1. Suspension of Cooperative Service.**

1. Suspension Reasons. The Cooperative may suspend a Member for the following reasons ("Suspension Reasons"):

a. Failing to pay for Cooperative Service or not complying with the Full Member Agreement or these Bylaws;

b. For good cause if the Member legally dissolves, or legally ceases to exist; tampers with, alters, interferes with, damages, or impairs any Cooperative Equipment; or,

c. voluntarily requests suspension.

2. Notice and Comment. Unless otherwise provided in these Bylaws, and following the occurrence of a suspension reason other than a Member's voluntary request for suspension, the Cooperative:

a. Provides the Member at least fifteen (15) days prior written notice of the Member's possible suspension and the underlying suspension reason; and

b. Notifies the Member that the Member has, and allows the Member, at least five (5) days after the effective date of the notice to comment upon the suspension reason, either orally or in writing.

Any written suspension notice provided by mail must be mailed to the Member's most current address shown on the membership list.

3. Effect of Member suspension upon Cooperative. Upon a Member's suspension, then:

a. The Cooperative's duties, obligations, and liabilities imposed by these Bylaws for the Member cease; and

b. The Cooperative may cease providing any Cooperative Service to the Member.

4. Effect of Member suspension upon Member. A suspended Member forfeits and relinquishes all rights provided in the Full Member Agreement and these Bylaws. In particular, a suspended Member forfeits and relinquishes any voting rights provided by these Bylaws. A suspended Member, however, remains subject to all obligations imposed by the Full Member Agreement and these Bylaws.

5. Lifting of Suspension. A Member's suspension is automatically lifted upon the Member rectifying, to the Cooperative's reasonable satisfaction, the underlying suspension reason within ten (10) days of the suspension. The Cooperative may lift any Member suspension for good cause as determined by the President.

**Section 3.2. Payment Termination**. Membership of the Member shall be terminated without further action by the Cooperative for a failure to make payment that began as a suspension and was not cured by the Member within thirty (30) days of the effective date of the suspension.

Termination for failure to pay does not release the Member from any debts, liabilities, or obligations owed to the Cooperative.

**Section 3.3. Termination for Reasons Other Than Failure to Pay**. The Membership of the Member shall be terminated without further action by the Cooperative after a suspension has been in place for forty-five (45) days without a resolution, unless the Member shall request in writing within thirty (30) days of the effective date of the suspension a hearing before the Board of Directors. The termination, but not the suspension, shall be held in abeyance until the Board votes on the termination. Termination of a Member does not release the Member from any debts, liabilities, or obligations owed the Cooperative. Upon a Member's termination from the Cooperative, and after deducting any amounts owed the Cooperative, the Cooperative shall return to the Member any amounts due to the terminated Member, if any, unless deemed otherwise for good cause by the Board.

**Section 3.4. Withdrawal**. Once a Member has satisfied its minimum term established in the Member Agreement, the Member may withdraw from the Cooperative on thirty (30) days written notice. Upon the Member becoming ineligible under the provisions of Section 2.1 for Membership in the Cooperative, the Member may withdraw on terms agreed to between the Member and the Cooperative. In all other cases, a Member may be permitted to withdraw from Membership in the Cooperative at such times and on such conditions as the President prescribes which are accepted by the Member.

**Section 3.5. Effect of Withdrawal or Termination**. Upon the withdrawal or termination in any manner of a Membership, the former Member shall be entitled to a refund of any over payment, less any amounts due the Cooperative. Should an action be commenced or an attorney employed to enforce payments of any amount owing on an account, the Member agrees to pay all costs of enforcement, including reasonable attorneys' fees and a late fee at the monthly periodic rate of 1.5% per month (18% per annum) until paid in full.

## ARTICLE IV
## MEETINGS OF MEMBERS

**Section 4.1. Organizational Board and Annual Meeting**. The affairs of the Corporation are managed by a Board of Directors. The names of the initial, organizational Directors are in the Charter of the Corporation. The organizational Directors shall serve until the solar facility is tested, commissioned, and certified, and then at the first annual meeting of the Members, the Members shall elect Directors consistent with the voting agreements, Charter, and these bylaws.

For the purpose of electing Directors, hearing and passing upon reports covering the previous fiscal year, and transacting such other business as may properly come before the meeting of the Members, the annual meeting of the Members shall be held on such date and beginning at such time as the Board from year to year shall provide. It shall be the responsibility of the Board to make adequate plans and preparations for and to encourage Member attendance at the annual meeting. Failure to hold the annual meeting at the designated time shall not constitute a forfeiture or dissolution of the Cooperative. These meetings may be conducted over zoom or any other electronic media.

**Section 4.2. Special Member Meetings**. A special meeting of the Members may be called by resolution of the Board or upon written request of at least the greater of three Members or twenty-five percent (25%) of all the Members, signed and dated within thirty (30) days following the first signature. The Cooperative will give notice of the special meeting to all Members. The special meeting shall be held in Madison County, Tennessee on such date, and beginning at such hour as designated by the Members calling the special meeting.

**Section 4.3. Notice of Member Meetings**. Written notice of the place, date and hour of the meeting, and, in the case of a special meeting or of an annual meeting at which business requiring special notice is to be transacted, the purpose or purposes of the meeting, shall be delivered to each Member not less than fourteen (14) nor more than forty-five (45) days before the date of the meeting. Such notice may be made personally; by United States Postal Service either with or without other documents, or electronically at a verified Member e-mail address. No matter that requires the affirmative votes of a clear majority of the Cooperative's Members attending a Member meeting shall be acted upon unless notice of such matter shall have been contained in the notice of the meeting. If mailed, such notice shall be deemed to be delivered when deposited in the United States mail, addressed to the Member at its address as it appears on the Cooperative's records, with postage thereon prepaid and postmarked at least fourteen (14) days before the meeting date. If transmitted via e-mail, such notice shall be deemed delivered when transmitted to a previously verified e-mail address for Member. The inadvertent failure of any Member to receive such notice shall not invalidate any action which may be taken by the Members at any such meeting. In making time calculations required by this section, the day of the meeting shall not be counted.

**Section 4.4. Quorum for Member Meetings**. Whenever ballots are cast by Members for the election of a director, attendance in person, by proxy, or by the submission of mailed ballots of at least twenty-five percent (25%) of the total Members of the Cooperative at any meeting of the Members shall constitute a quorum for the purpose of electing Directors and conducting other Cooperative business. Once a quorum is established for election of Directors, the results of the vote for Directors may be announced. Once a quorum is established for conducting Cooperative business, all business may be transacted despite the loss of a quorum. If a quorum is not established, the chair may recess the meeting to another time and date to any place within Madison County. The Secretary of the Cooperative, or his or her designee, shall notify all Members of the time, place and date of the recessed meeting by delivering notice thereof as provided in Section 4.3 of these Bylaws. At all meetings of the Members, the Secretary shall annex to the meeting minutes or incorporate therein by reference, a list of those who were present in person, by mailed-in ballot and by proxy.

**Section 4.5. Credentials and Elections Committee**. The Board appoints a Credentials and Elections Committee consisting of an uneven number of persons, not less than three (3) nor more than seven (7). Members of the Credentials and Elections Committee may not be close relatives or members of the same household of existing Directors or known candidates for Directors to be elected at such meeting. The Credentials and Elections Committee decides Member meeting issues. A Credentials and Elections Committee decision or action requires a vote of at least a majority of the Credentials and Elections Committee members present. Except as otherwise provided in these Bylaws, Credentials and Elections Committee decisions or actions during, or within a reasonable time before or after a Member meeting are final. In the event a member of the Credentials and Elections Committee resigns or becomes unable to participate due to illness or death, the Board may appoint, in its sole discretion an alternate member. The Committee may elect its own chairperson. In the exercise of its responsibility, the Credentials and Elections Committee shall have available to it the advice of counsel provided by the Cooperative. The Credentials and Elections Committee shall certify the results of all elections and other balloting. It shall be the responsibility of the Credentials and Elections Committee to establish or approve the manner of conducting Member registration at a Member meeting, to pass upon all questions that may arise with respect to the registration of Members in person and the authenticity and validity of mailed-in ballots and proxies, to oversee the counting of all ballots cast in any election, to rule upon all other questions that may arise relating to Member voting and the election of candidates for Director. The Credentials and Elections Committee's responsibilities include, but are not limited to, reviewing the process for the nomination and election of Directors and ruling on the validity of qualifications of candidates and nominees.

**Section 4.6. Voting**. Each Member who is not in a status of suspension as provided for in Section 3.1 shall be entitled to one vote and no more upon each matter submitted to a vote at a meeting of the Members. An Entity may vote through a duly designated representative, qualified as such upon registering for the meeting. Voting by Members shall be allowed upon the presentation to the Cooperative prior to, or upon registration at, each Member meeting of satisfactory evidence entitling the person to vote on behalf of the Entity. Such evidence shall not be required in any voting by mailed ballots for election of Directors. No one may vote on behalf of more than one Member. At all meetings of the Members at which a quorum is present all questions shall be decided by a majority of the Members voting thereon, except as otherwise provided by law or by the Cooperative's Charter or these Bylaws. Members may not accumulate their votes.

Members shall vote for the election of Directors by ballots mailed in or delivered to the address indicated in the notice of meeting on or before the date and hour indicated in such notice. Members shall not be permitted to vote in person for the election of Directors, but may attend and register and participate in all other proceedings of the meeting of Members to the fullest extent, and including the voting in person on all other questions that come before the meeting of Members. All elections of Directors shall be conducted so that the ballots will be return-mailed or delivered so as to assure that the way the vote is cast may not be determined and to assure that Members vote only once. The counting of mail ballots shall be conducted by or under the direction of the Credentials and Elections Committee prior to the meeting of the Members. The results will not be made official until certified by the Credentials and Elections Committee and announced by the chair of the Committee during the meeting. The provisions of the Section shall not apply to the election of a Director to fill a vacancy caused by the removal of a Director by the Members, in which case the provisions of Section 5.12 (Removal of Directors by Members) shall be followed.

The Board may authorize balloting by electronic means as an alternative to mail ballots or as replacement to mail ballots. Such authorization shall be in the form of a Board resolution that sets forth the process and security safeguards for the collection of electronic ballots. In the event the Board adopts electronic ballots, then these Bylaws shall be read to replace or add, as the case may be, "mail" ballots with "electronic" ballots as set forth in the Board resolution. The electronic ballots must meet at least the standards for mail ballots set forth in this Section.

**Section 4.7. Member Suggested Resolutions and New Business**. Any Member or Members wishing to have a resolution or an item of business placed on the agenda of any meeting of Members to be discussed or acted upon at the meeting shall submit the resolution or other items in writing to the Secretary not less than sixty (60) days before the scheduled meeting date. Notice of such resolution or other item of business so presented shall be given to the Membership with the notice of meeting.

## ARTICLE V
## DIRECTORS

**Section 5.1. General Powers and Responsibilities**. The business and affairs of the Cooperative shall be managed by a board of five (5) Directors, which shall exercise all of the powers of the Cooperative except such powers that are, by Law or the Charter or Bylaws reserved to the Members.

**Section 5.2. Director Conduct.** A Director shall discharge the Director's duties, in good faith; in a manner the Director reasonably believes to be in the Cooperative's best interests; when becoming informed in connection with the Director's decision-making function or devoting attention to the Director's oversight function, with the care that an individual in a like position would reasonably believe appropriate under similar circumstances; and in a manner in which the Director discloses or causes to be disclosed to other Directors information not known by them, but known by the Director to be material to discharging their decision-making or oversight functions, except that disclosure is not required to the extent that the Director reasonably believes that disclosure would violate a duty imposed under law, a legally enforceable obligation of confidentiality, or a professional ethics rule.

Unless a Director has knowledge making reliance unwarranted, then in discharging the Director's duties, the Director may rely on the performance, information or statements, including financial statements, presented by any of the following individuals:

1. one or more Cooperative Officers or employees whom the Director reasonably believes to be reliable and competent in the functions performed or the information, opinions, reports, or statements provided;

2. legal counsel, public accountants, or other individuals retained by the Cooperative regarding matters involving skills or expertise the Director reasonably believes are matters within the individual's professional or expert competence and as to which the individual merits confidence; and

3. a Board Committee of which the Director is not a member if the Director reasonably believes the Board Committee merits confidence.

**Section 5.3. Qualifications**. To become and remain a Director of the Cooperative, a person must meet and maintain continuously each of the following qualification requirements (collectively, the "Director Qualifications"):

1. Not be a close relative of an incumbent Director or an employee of the Cooperative.

2. Not be in any way financially interested in a competing enterprise that distributes electric energy.

3. Not have been convicted of a felony or any misdemeanor involving moral turpitude.

4. Be a citizen of the United States of America.

5. Be legally competent and physically able to enter contracts and exercise a Director's legal duties at the time of election and continuously during the Director's term of office.

**Section 5.4. Disqualification of Nominees, Candidates and Directors.**

1. The Credentials and Elections Committee shall determine whether nominees and candidates for Director are qualified through education or experience to assist the Board in governing the Cooperative.

2. If any Member alleges in a written statement signed by the Member and containing specific facts that a sitting Director does not meet any one or more of the Director Qualifications at a time after the Director's election, it shall be the duty of the Board to determine the validity of the such allegations according to the following procedures:

   a. Upon a majority vote of the Board that a Director is likely to have become disqualified, the Chairman of the Board shall notify the Director in writing of the basis for disqualification and provide the person an opportunity for a hearing before the Board. The Director must demand a hearing no later than the close of business on the tenth (10th) business day after the Director receives the notice or the notice is confirmed delivered to the Director's e-mail or physical address on file with the Cooperative, whichever is sooner. Failure to demand a hearing pursuant to this section shall mean that the Director has waived his or her right to a hearing.

   b. All disqualification hearings procedures shall adhere to Chapter XX, Disciplinary Proceedings, as set forth in Roberts Rules of Order, Newly Revised, except as otherwise stated herein. d. After the hearing, if held, or at a regular or special meeting if a hearing is not demanded, the members of the Board shall vote on whether the subject Director is disqualified. A two-thirds majority favoring disqualification shall affect the immediate removal of the person as Director. After removal, the Director's seat shall be treated as if it were vacant. If the Director is not removed, his Director Qualifications can be challenged again only through a new allegation of facts substantially different from the facts contained in the prior allegation.

   c. The decision of the Board is final.

3. If a majority of Directors authorized by these Bylaws complies with the Director Qualifications and approves a Board action, then the failure of a Director to comply with the Director Qualifications does not affect the Board action.

**Section 5.5. Elections.**

1. At each annual meeting of the Members, Directors shall be elected by secret mailed-in ballot by the Members.

2. Directors shall be elected by a plurality vote of the Members.

3. Cumulative voting shall not be allowed.

**Section 5.6. Tenure**. Directors shall be elected for terms of three (3) years or until their successors are elected and take office. The Board shall ensure staggered Director terms by dividing the total number of authorized Directors into groups of approximately equal number. Members must annually elect an approximately equal number of Directors. Directors shall take office at the first regular meeting of the Board following the annual meeting of the membership.

**Section 5.7. Nominations**. The Credentials and Elections Committee shall approve nominations, and shall:

1. (60) days before the meeting a list of nominations for Directors to be elected;

2. The list may include a brief biography or statement provided by the nominee or candidate.

3. If any nominee or candidate withdraws his name from nomination or dies between the time he or she is nominated as provided herein and sixty (60) days before the deadline for returning ballots to the Cooperative, and if as a result of such withdrawal or death there is less than one (1) candidate for election for any seat, the Credentials and Elections Committee shall nominate someone else to take the place of such withdrawn or deceased nominee.

**Section 5.8. Voting for Directors**. For purposes of electing Directors, each Member who is a Member of the Cooperative on the day thirty (30) days before the annual Membership meeting or any special meeting of the Members called for the purpose of electing Directors shall be entitled to cast one vote. Ballots marked in violation of this restriction shall be invalid and shall not be counted. An invalid ballot shall not affect in any manner whatsoever the validity of any action taken by the Board after the election of Directors.

**Section 5.9. Attendance at Board Meetings**. By operation of these Bylaws and without any need for action by the Board, any Director who misses more than three (3) regular meetings in any twelve-month period shall automatically be removed from office and his or her seat on the Board shall be declared vacant.

**Section 5.10. Director Resignation**. A Director may resign at any time by delivering written notice of resignation to the Chairman. A resigning Director may request that the resignation be effective at a future date, which the Board may grant or deny in its sole discretion.

**Section 5.11. Removal of Directors by Members**. Any Member may bring one or more charge(s) for grossly negligent, fraudulent or criminal act, or omission significantly and adversely affecting the Cooperative against any one or more Director(s) and may request the removal of such Director(s) by reason thereof by filing with the Chairman such charge(s) in writing, together with a petition signed by not less than twenty-five percent (25%) of the then-total Members of the Cooperative which petition shall call for a special meeting, the stated purpose of which shall be to hear and act upon such charge(s) and, if one or more Directors are recalled, to elect their successor(s), and which specifies the place, time and date thereof not sooner than forty (40) days nor more than eighty (80) days after filing of such petition, or which requests that the matter be acted upon at the subsequent annual Member meeting if such meeting will be held no sooner than forty (40) days nor more than eighty (80) days after the filing of such petition. Each page of the petition shall, in the forepart thereof, state the name(s) and address(es) of the Member(s) filing such charge(s), a verbatim statement of such charge(s) and the name(s) of the Director(s) against whom such charge(s) is (are) being made. The petition shall be signed by each Member in the same name as he is billed by the Cooperative and shall state the signatory's address as the same appears on such billings. Notice of such charge(s), verbatim, of the Director(s) against whom the charge(s) have been made and of the Member(s) filing the charge(s) and the purpose of the meeting shall be contained in the notice of the meeting, or separately noticed to the Members not less than fourteen (14) days prior to the Member meeting at which the matter will be acted upon.

Such Director(s) shall be informed in writing of the charges after they have been validly filed and at least twenty (20) days prior to the meeting of the Members at which the charges are to be considered, and shall have an opportunity at the meeting to be heard in person, by witnesses, by counsel, or any combination of such, and to present evidence in respect of the charge(s); and the Member(s) bringing the charges shall have the same opportunity, but must be heard first. The question of the removal of such Director(s) shall, separately for each if more than one has been charged, be considered and voted upon at such meeting, and any vacancy created by such removal shall be filled by vote of the Members at such meeting without compliance with the foregoing provisions with respect to nominations, except that nominations shall be made from the floor. The question of the removal of a Director shall not be voted upon at all unless some evidence in support of the charge(s) against him or her are presented during the meeting through oral statements, documents or otherwise. Any Director elected by the Members as a replacement for a removed Director shall meet all eligibility requirements for being a Director and shall serve the unexpired portion of the removed Director's term. No Director may be removed for lawfully opposing or resisting any transfer of Cooperative assets.

**Section 5.12. Vacancies**. Subject to the provisions of these Bylaws with respect to the filling of vacancies caused by the removal of a Director by the Members, a vacancy occurring in the Board shall be filled by the affirmative vote of a majority of the remaining Directors. A Director thus elected shall fill the unexpired term of the Director whose office was originally vacated.

**Section 5.13. Compensation; Expenses**. A Director is not an employee of the Cooperative. A

Directors serves as an uncompensated volunteer without benefits. However, as determined or approved by the Board, the Cooperative may reimburse Directors for their expenses for attending a: (1) Board meeting; (2) function, meeting, or event involving or relating to the Cooperative; or (3) function, meeting, or event involving, relating to, or reasonably enhancing the Director's ability to serve in, the role of Director. The Board must determine or approve the manner, method, and amount of any Director expense reimbursement.

**Section 5.14. Rules, Regulations, and Contracts**. The Board shall have power to make, adopt, amend, abolish and promulgate such rules, regulations, and contracts, not inconsistent with Law or the Cooperative's Charter or Bylaws, as it may deem advisable for the management, administration and regulation of the business and affairs of the Cooperative.

**Section 5.15. Accounting System and Report**. The Board shall cause to be established a complete accounting system of the Cooperative's financial operations and condition, and may, after the close of each fiscal year, cause to be made a full, complete and independent audit of the Cooperative's accounts, books and records reflecting operations during and financial condition as of the end of such year.

**Section 5.16. Reserves**. The Cooperative is a non-profit operated for the benefit of its Members. The Member Agreement may establish a maximum billing amount or rate for the Member. Therefore, the Cooperative will not hold more than twelve months in budgeted expenses as a surplus. Any excess will be distributed annually to the Members based on usage or credited against their Cooperative Service.

## ARTICLE VI
## MEETINGS OF DIRECTORS

**Section 6.1. Regular Board Meetings**. The Board shall regularly meet at the date, time, and location determined by the Board ("Regular Board Meeting") through a resolution. Once the resolution establishing the Regular Board Meeting schedule is adopted, the Board may hold Regular Board Meetings without further notice. For good cause, the Chairman may change the date, time, or location of a Regular Board Meeting.

**Section 6.2. Special Board Meetings**. The Board, the Chairman, the President, or at least two Directors may call a special meeting of the Board ("Special Board Meeting") by instructing the Cooperative to provide each Director at least five days prior written or Electronic notice indicating the date, time, location, and purpose of the Special Board Meeting. Special Board Meetings may also be held via telephone conference call or via zoom or similar service.

**Section 6.3. Waiver of Board Meeting Notice**. At any time before, during, or after a Board Meeting or Special Board Meeting, a Director may waive notice of such meeting by delivering to the Cooperative a written or Electronic waiver of notice signed by the Director and later filed with the Board Meeting minutes or the Cooperative's records. In addition, a Director's attendance at, or participation in, a Board Meeting waives notice of the Board Meeting and any matter considered at the Board Meeting, unless the Director:

1. at the beginning of the Board Meeting objects to holding or transacting business at the Board Meeting or lack of, or defective, notice of the Board Meeting or Special Board Meeting; and

2. does not vote for, or assent to, an objected matter.

**Section 6.4. Quorum**. The presence of a majority of the Directors in office shall be required for the transaction of business and the affirmative votes of a majority of the Directors in office shall be required for any action to be taken. A Director who by Law or by these Bylaws is disqualified from voting on a particular matter shall not, with respect to consideration of and action upon that matter, be counted in determining the number in office. A Director may not vote by proxy. An agreement signed by Directors providing the manner in which a Director must vote is not valid and is unenforceable. If less than a quorum is present at a meeting, a majority of the Directors present may recess the meeting until a later date, but shall cause any absent Directors to be duly notified of the time and place of such recessed meeting.

**Section 6.5. Procedures for Board Meetings**. Except as otherwise provided in these Bylaws, a Regular Board Meeting or Special Board Meeting (collectively, a "Board Meeting") may implement those meeting procedures the Board deems most appropriate. A Board Meeting or a Board Committee meeting may be conducted with physically absent Directors participating, and deemed present in person, through any means of communication by which all Directors participating in the Board Meeting may simultaneously hear each other during the Board Meeting.

Without a Board Meeting, the Board may take an action required or permitted to be taken at a Board Meeting by "Director Written Consent" if the action is: (1) taken by all Directors; and (2) evidenced by one or more written consents ("Director Written Consent") (A) describing the action taken; (B) signed by each Director; (C) delivered to the Cooperative; and (D) included with the Cooperative's Board Meeting minutes. Except as a different effective date is provided in the Director Written Consent, action taken by Director Written Consent is effective when the last Director signs the Director Written Consent. A Director Written Consent has the effect of, and may be described as, a Board Meeting vote. Prior to his or her assent to a Director Written Consent, a Director may object for any reason and thereby refuse to allow the Director Written Consent to become effective. If the Chairman is not present at a Board Meeting, then the Directors attending the Board Meeting must elect a Director to preside over the Board Meeting.

The Board may promulgate or approve rules, policies, and procedures regarding:

1. The conduct of Board Meetings.

2. The attendance at, participation in, or presentation during Board Meetings by persons other than Directors; or

3. The right to access, inspect, or copy any minutes, record, or other document relating to any Board Meeting by persons other than Directors; or

**Section 6.6. Committees**. The Board may create a committee of the Board ("Board Committee") and appoint Directors and others to serve on the Board Committee. A Board Committee must consist of at least one Director. The Board may create a committee of the Members ("Member Committee") and appoint Members, including Directors, to serve on the Member Committee. The Board may appoint one or more Directors or Members, respectively, as alternate members of any Board or Member Committee to replace any absent or disqualified Committee member during the Committee member's absence or disqualification. A Member Committee may act as specified by the Board, but may not exercise Board authority. Except as otherwise provided in this Bylaw, the Board may authorize a Board Committee to exercise Board authority. Although a Board Committee may recommend, a Board Committee may not act, to: (1) retire and pay debts and leases; (2) approve the Cooperative's dissolution or merger, or the sale, pledge, or Transfer of all, or substantially all, assets; (3) elect, appoint, disqualify, or remove a Director, or fill a Board or Board Committee vacancy; or (4) adopt, amend, or repeal Bylaws.

## ARTICLE VII
## OFFICERS

**Section 7.1 Officer Standard of Conduct**. An Officer shall discharge the Officer's duties: (1) in good faith; (2) with the care an ordinarily prudent person in a like position would exercise under similar circumstances; and (3) in a manner the Officer reasonably believes to be in the Cooperative's best interests. An Officer shall: (1) inform the Board, or the superior Officer or Board Committee to whom or which the Officer reports, of information regarding the Cooperative's affairs known to the Officer, within the scope of the Officer's duties and functions, and known to the Officer to be material to the superior Officer or Board; and (2) inform the Board, the superior Officer to whom the Officer reports, or another appropriate person within Cooperative of any actual or probable material violation of Law involving the Cooperative, or material breach of duty to the Cooperative by a Cooperative Officer, employee, or agent, that the Officer believes has occurred or is likely to occur.

**Section 7.2. Required Officers; Other Officers; Election; Terms**. The Cooperative must have at least a President, Secretary, and a Treasurer ("Required Officers"). The Board may create other executive officers that it deems appropriate. The Board shall elect Required Officers: (1) at the first Regular Board Meeting following each annual Member meeting, or as soon after each annual Member meeting as reasonably possible and convenient and (2) by affirmative vote of a majority of Directors in office. The Board may create or appoint Other Officers at any time. The Board may authorize a Required Officer to delegate duties and responsibilities to a third party with expertise in that area.

**Section 7.3. Removal**. Any officer, agent or employee elected or appointed by the Board may be removed by the Board whenever in its judgment the best interests of the Cooperative will thereby be served.

**Section 7.4. Vacancies**. A vacancy in any office elected by the Board may be filled by the Board for the unexpired portion of the term.

**Section 7.5. President**. The President may also be referred to as the Manager or General Manager. The President:

1. May sign Member Agreements, any deeds, mortgages, deeds of trust, notes, bonds, contracts or other instruments authorized by the Board to be executed, except in cases in which the signing and execution thereof shall be expressly delegated by the Board or by these Bylaws to some other officer or agent of the Cooperative, or shall be required by law to be otherwise signed or executed; and

2. In general, shall perform all duties incidental to the office of President and such other duties as may be prescribed by the Board from time to time.

**Section 7.6. Secretary**. Except as otherwise provided by the Board or these Bylaws, the Secretary:

1. shall be responsible for preparing, or supervising the preparation of, minutes of Board and Member meetings;
2. shall be responsible for maintaining and authenticating the Cooperative's records;
3. may affix the Cooperative's seal to a document authorized or approved by the Board or Members; and
4. shall perform all other duties, shall have all other responsibilities, and may exercise all other authority prescribed by the Board.

**Section 7.7 Treasurer**. Except as otherwise provided by the Board or these Bylaws, the Treasurer shall perform all duties, shall have all responsibility, and may exercise all authority that may be prescribed by the Board.

**Section 7.8. Delegation of Secretary's and Treasurer's Responsibilities**. Notwithstanding the duties, responsibilities and authorities of the Secretary and of the Treasurer hereinbefore provided in this Article, the Board by resolution may, except as otherwise limited by Law or these Bylaws, delegate, wholly or in part, the responsibility and authority for, and the regular or routine administration of, one or more of such officers, such duties to one or more Cooperative employees or subcontractors. To the extent that the Board does so delegate with respect to either such officer, that officer as such shall be released from such duties, responsibilities and authorities.

**Section 7.9. Compensation**. The compensation, if any, of any officer, agent or employee shall be fixed or set according to a plan approved by the Board.

**Section 7.10. Reports**. The officers of the Cooperative shall annually submit to the Members reports covering the business of the Cooperative for the previous fiscal year and showing the financial condition of the Cooperative at the close of such fiscal year.

**Section 7.11. Indemnification**. The Cooperative shall indemnify present and former Directors, officers, agents and employees against liability to the extent that their acts or omissions constituting the grounds for alleged liability were performed in their official capacity and, if actionable at all, were based upon good faith business judgments in the belief the acts or omissions were in the best interests of the Cooperative or were not against the best interest of the Cooperative. The Cooperative may purchase insurance to cover such indemnification.

ARTICLE VIII

## CONTRACTS, CHECKS AND DEPOSITS

**Section 8.1. Contracts**. Except as otherwise provided in these Bylaws, the Board may authorize any officer or officers, agent or agents to enter into any Member Agreement or other contract or execute and deliver any instrument in the name and on behalf of the Cooperative, and such authority may be general or confined to specific instances.

**Section 8.2. Checks, Drafts, etc**. All checks, drafts or other orders for the payment of money, and all notes, bonds or other evidences of indebtedness issued in the name of the Cooperative shall be signed by such officer, officers, agent or agents, employee or employees of the Cooperative and in such manner as shall from time to time be determined by resolution of the Board.

**Section 8.3. Deposits**. All funds of the Cooperative shall be deposited from time to time to the credit of the Cooperative in such bank, banks, or other financial institutions as the Board may select. The Board may delegate to an officer of the Cooperative the authority to effectuate such deposits and to manage Cooperative funds and deposits in the best interest of the Cooperative, such delegation being consistent with the Board's fiduciary duties and standard of conduct set forth in Section 5.2.

## ARTICLE IX
## NON-PROFIT OPERATION

**Section 9.1. Interest or Dividends on Capital Prohibited**. The Cooperative shall at all times be operated on a cooperative non-profit basis for the mutual benefit of its Members and patrons. The term "Patron" means: a Member or any person to whom the Cooperative is obligated to allocate Capital Credits. No interest or dividends shall be paid or payable by the Cooperative on any capital furnished by its Patrons. The term "Capital Credits" means the amounts allocated to a Patron and contributed by the Patron to the Cooperative as capital.

**Section 9.2. Patronage Capital in Connection with Generation, Storage and Distribution Equipment and Installation.** The Cooperative's operations in generating, storing, and distributing supplemental electric energy shall be conducted so that all Patrons who furnish capital or who provide for the lease of capital assets to the Cooperative receive a Capital Credit. At its inception, the Cooperative will lease equipment and receive electrical energy from a lease agreement with Community Development Enterprises - Jackson I. Community Development Enterprises - Jackson I will obtain tax equity financing for the equipment, construct a solar facility and related distribution to Members. Community Development Enterprises - Jackson I is an initial Patron. The Cooperative will receive initial capitalization and anticipates future capital needs being satisfied from it Patron(s). This capitalization will cover obligations which are incurred prior to the date on which the Cooperative begins receiving payment from Members for the Cooperative Service. In order to induce patronage and to assure that the Cooperative will operate on a non-profit basis, the Cooperative is obligated to account on a patronage basis to its Patrons for all amounts received. The books and records of the Cooperative shall be set up and kept in such a manner that at the end of each fiscal year the amount of capital, if any, so furnished by each Patron is clearly reflected and credited in an appropriate record to the capital account of each Patron. The Cooperative shall within a reasonable time after the close of the fiscal year notify each Patron of the amount of capital so credited to its capital account. All such amounts credited to the capital account of any Patron shall have the same status as though they had been paid to the Cooperative in cash in pursuance of a legal obligation to do so, and the Patron had then furnished the Cooperative corresponding amounts for capital. The Cooperative will retire these Capital Credits over time. The Cooperative authorizes the Patron to perfect its security interest in its Capital Credits by filing a financing statement. Additionally, the Patron(s) and the Cooperative may agree to secure loans from third parties through a security agreement signed or authenticated by a Patron, in which the Patron grants the third party a security interest in Capital Credits allocated to the Patron to secure a loan to the Cooperative.

**Section 9.3. Patronage Capital in Connection with Furnishing Electric Energy**. The Cooperative's operations in furnishing supplemental electric energy shall be conducted so that all Patrons who furnish capital receive a Capital Credit. In order to induce patronage and to assure that the Cooperative will operate on a non-profit basis, the Cooperative is obligated to account on a patronage basis to its Members for all amounts received from the furnishing of electric energy in excess of operating costs and expenses properly chargeable against the furnishing of electric energy. The Cooperative will maintain a surplus that is no greater than twelve (12) months of budgeted expenses. All such amounts in excess of operating costs and expenses which is represented by this surplus is considered capital furnished by a Patron based on usage of electrical energy. The Cooperative is obligated to pay by credits to a capital account for each patron all such amounts in excess of operating costs and expenses. The books and records of the Cooperative shall be set up and kept in such a manner that at the end of each fiscal year the amount of capital, if any, so furnished by each Patron is clearly reflected and credited in an appropriate record to the capital account of each Patron. The Cooperative shall within a reasonable time after the close of the fiscal year notify each Patron of the amount of capital so credited to its capital account. All such amounts credited to the capital account of any Patron shall have the same status as though they had been paid by the Patron to the Cooperative in cash in pursuance of a legal obligation to do so, and the Patron had then furnished the Cooperative corresponding amounts for capital. Other than operating margins, funds and amounts received by the Cooperative that exceed the Cooperative's costs and expenses (also known as non-operating margins-interest) may be allocated as Capital Credits to Patrons in the same manner as the Cooperative allocates operating margins to Members who become Patrons, retained or used by the Cooperative and used to pay or offset any Cooperative cost or expense. Any excess surplus held by the Cooperative will be used to retire Capital Credits at the end of each year.

**Section 9.4. Allocation of Capital Credits to Patrons.** Consistent with these Bylaws and the Membership Agreement, the Board will determine the manner, method, and timing of allocating Capital Credits. The Cooperative may retire Capital Credits or use or invest unretired Capital Credits for its capital needs. The Board shall have the power to adopt rules providing for the separate treatment of that portion (that is, power supply or other service or supply portion) of capital credited to the accounts of patrons which corresponds to capital credited to the account of the Cooperative by an organization furnishing electric service or any other service or supply to the Cooperative. Such rules shall;

1. Establish a method for determining the portions of such capital credited to each patron for each applicable fiscal year;

2. Provide for separate identification on the Cooperative's books of such portions of capital credited to the Cooperative's Patrons;

3. Provide for appropriate notifications to Patrons with respect to such portions of capital credited to their accounts; and,

4. Preclude a general retirement of such portions of capital credited to Patrons for any fiscal year prior to the general retirement of other capital credited to Patrons for the same year or of any capital credited to Patrons for any prior fiscal year.

In the event of dissolution or liquidation of the Cooperative, after all outstanding indebtedness of the Cooperative shall have been paid, outstanding Capital Credits shall be retired without priority on a pro rata basis before any payments are made on account of property rights of Members. If, at any time prior to dissolution or liquidation, the Board shall determine that the financial condition of the Cooperative will not be impaired thereby, the capital then credited to patrons' accounts may be retired in full or in part.

**Section 9.5. Retirement of Capital Credits.** After operations begin, the Board shall determine the method, basis, priority and order of retirement, if any, for all amounts furnished as capital. Subject to amounts due, capital credited to the account of each Patron shall be assigned only on the books of the Cooperative pursuant to written instructions from the assignor and only to successors in interest or successors in occupancy in all or a part of such former Member-Patron's premises served by the Cooperative. The Cooperative, before retiring any capital credited to any patron's account, shall deduct therefrom any amount owing by such patron to the Cooperative, together with interest thereon in effect when such amount became overdue, compounded annually.

Patrons may elect to contribute all or a part of the capital credits to the Cooperative or, if formed in the future, to the Community Services Cooperative Foundation of Jackson. Such election will be made in writing. The patrons of the Cooperative, by dealing with the Cooperative, acknowledge that the terms and provisions of the Charter and Bylaws shall constitute and be a contract between the Cooperative and each Patron, and both the Cooperative and the Patrons are bound by such contract, as fully as though each Patron had individually signed a separate instrument containing such terms and provisions.

## ARTICLE X
## PAYMENT OF EXPENSES IN SELLOUT DELIBERATIONS

In the event that an officer, Director, Member, Patron, or group of Members shall incur any reasonable expenses, costs, and/or attorney's fees in connection with opposing the selling of all or substantially all of the assets of the Cooperative, and provided such expenses, costs and/or fees have not been or are not to be reimbursed or paid by any other person, firm, association or corporation, such costs, expenses and fees shall be paid by the Cooperative provided they were incurred in opposition to such proposal.

## ARTICLE XI
## WAIVER OF NOTICE

Any Member or Director may waive, in writing, any notice of meetings required to be given by these Bylaws. Personal attendance at any meeting of the Members or Directors shall constitute a waiver of notice of such meeting unless such personal attendance shall be for the express purpose of objecting to the transaction of any business on the ground that the meeting shall not have been lawfully called or convened. Any Member or Director attending any meeting for the purpose of making such objection shall notify the Secretary prior to or at the beginning of the meeting of his objections. Waiver of Director meetings is also subject to Section 6.3.

## ARTICLE XII
## DISPOSITION & PLEDGING OF PROPERTY; DISTRIBUTION OF SURPLUS ASSETS ON DISSOLUTION

**Section 12.1. Transfer of Cooperative Assets**. The Board may pledge assets of the Cooperative to secure indebtedness. The Board may transfer, mortgage, pledge, dedicate to repayment, or encumber any Cooperative asset in the regular course of business for the furnishing of Cooperative Services. Except for the initial lease of equipment or the purchase or lease of real property at the inception of the Cooperative, the Members must approve by a two-thirds vote the sale of substantially all of the assets of the Cooperative to a third party. The Board shall approve any other sale, lease, exchange, or other disposition of any Cooperative property or Cooperative asset, including the following:

1. To secure indebtedness;

2. Pursuant to condemnation or threat of condemnation;

3. Pursuant to an existing legal obligation;

4. Associated with a consolidation or merger with another cooperative entity;

5. To another entity operating on a cooperative basis and providing electric energy; or,

6. To a Cooperative subsidiary, the Cooperative shall not transfer, during any twelve (12) month period, more than ten per centum (10%) of the Cooperative's assets unless:

    a. At the expense of the person seeking to purchase, lease or acquire the Cooperative's assets, the Board appoints three (3) independent appraisers, each of whom, within a reasonable time of appointment, evaluates and renders an appraisal valuing the Cooperative's assets specified in the proposed transfer;

    b. Within a reasonable time of receiving the appraisals, the Cooperative invites any other entities operating on a cooperative basis, providing electric energy, and primarily located within the same state as, or within a state adjacent to, the state in which the Cooperative is primarily located to submit proposals to purchase, lease, or acquire the Cooperative's assets specified in the proposed transfer, or to merge or consolidate with the Cooperative;

c. The Board approves the proposed transfer;

d. By mail ballot, at least two-thirds (2/3) of the total Membership approves the proposed transfer; and

e. Notice of any Member meeting at which Members will consider the proposed transfer states that one of the purposes of the Member meeting is to consider the transfer, and includes a copy or summary of the proposed transfer.

In proportion to the value or quantity of Cooperative services used by Members during the period in which the Cooperative owned a Cooperative asset, the Cooperative allocates and credits to Members as Capital Credits any consideration received for the Cooperative's assets that exceed the amount paid for the Cooperative assets.

**Section 12.2. Distribution of Surplus Assets on Dissolution**. Upon the Cooperative's dissolution, any assets remaining after all liabilities or obligations of the Cooperative have been satisfied and discharged shall be distributed among all persons who shall have been Members of the Cooperative at any time during the fiscal year in which such dissolution is authorized by vote of the Members or any of the five (5) next preceding years, prorated to them on the basis that their respective patronage during all such years bears to the total receipts of the Cooperative for all such years. Provided, however, that if in the judgment of the Board the amount of such surplus is too small to justify the expense of making such distribution, the Board may, in lieu thereof, donate, or provide for the donation of, such surplus to one or more nonprofit charitable or educational organizations that are exempt from federal income taxation.

## ARTICLE XIII
## FISCAL YEAR

The Cooperative's fiscal year shall begin on the first day of the month of January of each year and end on the last day of the month of December following.

## ARTICLE XIV
## RULES OF ORDER

Parliamentary procedure at all meetings of the Members, of the Board, of any committee provided for in these Bylaws and of any other committee of the Members or Board which may from time to time be duly established shall be governed by the most recent edition of Robert's Rules of Order, except to the extent such procedure is otherwise determined by these Bylaws, by Law, by the Cooperative's Charter, or by action of the Board.

## ARTICLE XV
## LEGAL FORMALITIES

These Bylaws are governed by, and are to be interpreted under the laws of the State of Tennessee and any proceedings or actions arising therefrom shall be brought in a forum of competent jurisdiction located therein. The Board reserves the right to amend the Bylaws of the Cooperative at any time and for any reason consistent with the purpose of the Cooperative. Such amendment may be adopted without prior notice to Members, and such amendment shall become binding on the Members automatically on the effective date of the amendment. The titles and headings of the Charter and Sections of these Bylaws are for convenience and reference only, and do not affect the interpretation of any Bylaw, Article, Section, or sub-section thereof. The failure of the Cooperative to assert any right or remedy provided by these Bylaws does not waive the right or remedy provided by these Bylaws. These Bylaws and the Member Agreement constitute the entire agreement between the Cooperative and the Members and supersede any prior or contemporaneous oral or written communication or representation. The invalidity of any Bylaw provision does not invalidate the remaining Bylaw provisions. In the event a provision of these Bylaws is found to be invalid, the remaining provisions are to be read in such a manner as to give the fullest effect to the entire document as if, to the extent legally possible, the invalid provision were valid.

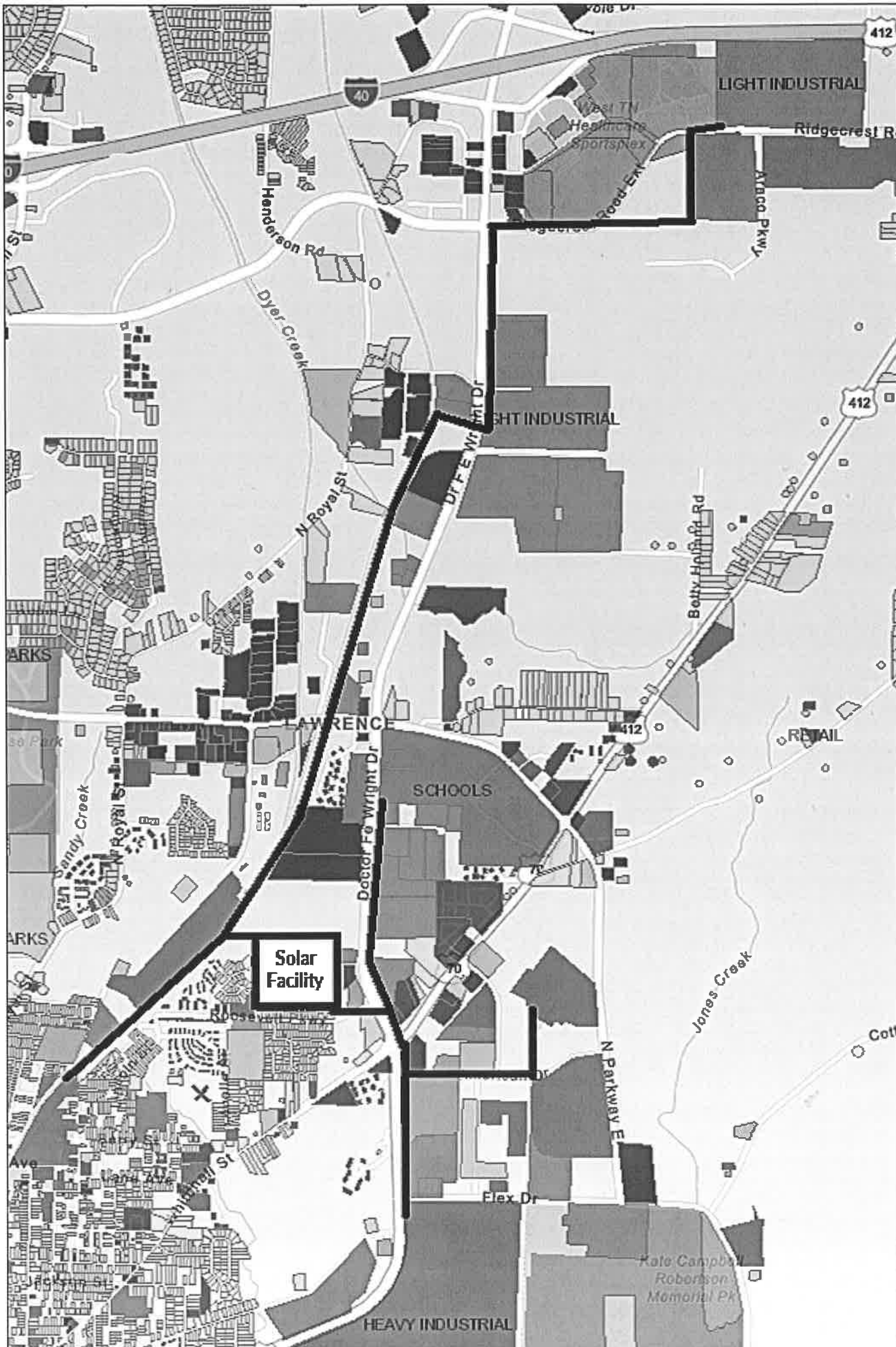
## ARTICLE XVI
## AMENDMENTS

Except as otherwise provided in these Bylaws, these Bylaws may be adopted, amended, or repealed only by two-thirds of Directors present and entitled to vote at a regular or special meeting of the Board. Except as otherwise provided in a Bylaw Amendment, the Amendment is effective the day after the vote approving the Amendment. The Cooperative must notify Members of amended Bylaws at the annual meeting following the amendment.

Notice of a Board meeting at which Directors will consider a proposed Bylaw amendment must: (1) state that the purpose or one of the purposes, of the Board meeting is to consider the proposed Bylaw amendment; and (2) contain, or be accompanied by, a copy or summary of the proposed Bylaw amendment. After notice of a proposed Bylaw amendment, the proposed Bylaw amendment may not be materially changed before the meeting at which the amendment will be considered.

Robert Starr, Secretary

# EXHIBIT 3


412
LIGHT INDUSTRIAL
40
West TN Healthcare Sportsplex
Ridgecrest Rd
Henderson Rd
Ataco Pkwy
Dyer Creek
412
LIGHT INDUSTRIAL
Dr F E Wright Dr
N Royal St
Betty Hainfd Rd
ARKS
LAWRENCE
412
RETAIL
SCHOOLS
Doctor Fe Wright Dr
Sandy Creek
N Royal St
70
Solar Facility
ARKS
Jones Creek
Roosevelt Pkwy
N Parkway E
Ave
Whitehall St
Flex Dr
Kate Campbell Robertson Memorial Pk
HEAVY INDUSTRIAL
70

# EXHIBIT 4

**JACKSON SUSTAINABILITY COOPERATIVE**
**CONDITIONAL MEMBER AGREEMENT**

AGREEMENT by and between:

JACKSON SUSTAINABILITY COOPERATIVE, ("JSC")
a Tennessee nonprofit corporation

and

______________________________ ("MEMBER")
*Print Name*

______________________________
*Street*

______________________________
*City/State/Zip*

______________________________
*Member Number*

______________________________
*Email*

______________________________
*Taxpayer Identification Number*

**RECITALS:**

WHEREAS, a small group of manufacturers and commercial operators with facilities in the Roosevelt Parkway area of Jackson, Tennessee desire to move to renewable energy and contribute to Jackson's redevelopment through participation in the Jackson Sustainability Cooperative, a Tennessee non-profit corporation;

WHEREAS, certain manufacturers and commercial operators in the neighborhood have corporate goals and aspirations of improving environmental quality through promoting and developing energy conservation through research while at the same time lowering energy costs, improving energy efficiency and energy quality to protect equipment, and avoiding the costs of power outages;

WHEREAS, certain manufacturers and commercial operators currently experience high peak-demand charges for electricity, as well as periodic power outages from construction, accidents and storms;

WHEREAS, these manufacturers and commercial operators may benefit from participating as a Member in the Jackson Sustainability Cooperative to share a solar facility in their neighborhood;

WHEREAS, the proposed solar facility connects directly to the Member to provide supplemental electrical energy through smart meters that precisely monitor electrical loads without backfeeding the existing municipal electricity provider's grid;

WHEREAS, the applicant desires to become a conditional Member for the purpose of allowing the Jackson Sustainability Cooperative to evaluate its energy profile to determine if it is eligible for the supplemental energy from sustainable sources provided by the Jackson Sustainability Cooperative, leading to full Membership and participation in the solar facility.

**WITNESSETH**

NOW THEREFORE, in consideration for a detailed analysis of electrial profile and potentially receiving an offer to participate in supplemental electrical energy from the shared solar facility, and the covenants and obligations contained herein, the parties agree as follows:

1. JACKSON SUSTAINABILITY COOPERATIVE ("JSC") is an electric cooperative incorporated and operating under the Tennessee Electric G&T Cooperative Act of 2009, T.C.A. §48-69-101. JSC is initially controlled by its founding board as set forth in the Charter. After supplemental electric energy is provided to the Members, then JSC will be controlled by its members and operate on a nonprofit basis to provide supplemental electric service ("Service") to those Members who meet its requirements, and not to the general public.

2. This Agreement makes the undersigned Applicant a temporary, conditional Member ("Member"). After the Member provides JSC with all requested information to analyze, within 60 days JSC will review the Member's current electrical energy profile experienced at Member's service location ("Premises"). JSC will determine if the Member's electrical profile is a suitable fit with the capabilities of JSC to determine if the conditional Member would benefit from participating as a full Member who receives supplemental electrical energy from JSC. This Agreement making the Applicant a conditional Member is not a contract for electrical energy provided by JSC. If JSC determines that the electrical needs of the conditional Member fit well with the capabilities of the solar facility, then JSC will offer a second agreement to become a full member with pricing and terms to approve interconnecting with JSC's solar facility for supplemental electrical energy.

3. The Member has no obligation to become a full Member of JSC. The conditional Member agrees to provide JSC with the following (collectively the "Information"):

a. A general description of the Member's business;
b. A description of what is manufactured and the processes;
c. A description of the labor-shift hours;
d. A short list of major equipment used in the process;
e. An electrical single-line drawing for the plant;
f. Excel file showing electrical usage per meter by 15, 30, or 60 minute intervals, for the prior 3 years if possible, otherwise at least 1 year;
g. Copy of agreement with municipal utility;
h. Monthly utility bills for prior 3 years if possible, otherwise at least 1 year; and
i. Permission to pull the Member's Dun & Bradstreet credit report.

4. JSC shall receive and use the Information solely for the purpose stated above and shall not use it for any other purpose. JSC and its agents and employees will hold in strict trust and confidence all Information that the Member furnishes and discloses or otherwise makes available to JSC. JSC shall not photograph the inside of the Premises at any place other than at the existing master breaker box where the Member receives power from the municipal provider. JSC will not reveal or otherwise disclose or make available any Information it receives to any person or parties other than JSC's contract technicians who reasonably have a need to possess knowledge of such Information for the purpose stated above and who have signed a confidentality agreement with JSC on terms at least as strict as those in terms in this Agreement.

5. Upon the conclusion of the evaluation process described above, JSC shall return to the Member all Information it received. JSC shall not be subject to the restrictions imposed herein with respect to any Information obtained by it from the Member pursuant to this Agreement if:

   a. JSC can show by written documentation that the Information was known to it at the time of the receipt from the Member;

   b. The Information was at the time of disclosure by the Member to JSC was or thereafter becomes a matter of public knowledge through no violation of this Agreement by JSC; or

   c. the Information was or hereafter is obtained properly by JSC from another source without any restrictions of confidentiality or use.

6. This Agreement shall be governed by the laws of the State of Tennessee.

7. The obligations contained in this Agreement with respect to any Information shall remain in effect for five (5) years from date of disclosure of such Information.

8. This Agreement constitutes the entire agreement between the parties with respect to the subject matter hereof, and it supersedes all prior or contemporaneous agreements, negotiations or understandings with respect to said subject matter. This Agreement may be amended or waived only by a written instrument duly signed by both parties.

IN WITNESS WHEREOF, the parties hereto have affixed their hands and seal the date first shown above.

**ATTEST:**

| JACKSON SUSTAINABILITY COOPERATIVE: | MEMBER/APPLICANT: |
| --- | --- |
| By:____________________________<br>Dennis Emberling, President | By:____________________________<br>Its: ___________________________ |
| Date:___________________________ | Date:___________________________ |

**JACKSON SUSTAINABILITY COOPERATIVE**
**FULL MEMBER AGREEMENT**

AGREEMENT by and between:

JACKSON SUSTAINABILITY COOPERATIVE ("JSC")
a Tennessee nonprofit corporation

and

ABC MANUFACTURING, INC. ("MEMBER")

__________________________________
*Member Number*

## RECITALS:

WHEREAS, Jackson Sustainability Cooperative has determined that the conditional Member's energy profile indicates that it can benefit from participating as a Member in the Jackson Sustainability Cooperative to share a solar facility with other similarly situated manufacturers and commercial operators who share the same vision of improving environmental quality, promoting conservation, improving energy quality and efficiency, avoiding the costs of power outages, and lowering energy costs without capital expenditures;

WHEREAS, the conditional Member desires to become a full Member who enjoys the benefits of a shared solar facility under the terms and conditions provided in this Member Agreement.

## WITNESSETH[1]

NOW THEREFORE, in consideration for providing supplemental electrical energy, covenants and obligations contained herein, the parties agree as follows:

1. Cooperative and Membership. JACKSON SUSTAINABILITY COOPERATIVE ("JSC") is an electric cooperative incorporated and operating under the Tennessee Electric G&T Cooperative Act of 2009, T.C.A. § 48-69-101. This Agreement accepts Member as a full Member of JSC. Member agrees to abide by the terms of this Agreement at Member's service location(s). The undersigned Member agrees to be bound by the governing Documents, including JSC's: (a) Charter; (b) Bylaws; (c) service rules; (d) rate or price schedules; and (e) rules adopted by JSC's board of directors for the safe delivery of services,

[1] This agreement is adapted, in significant part, from a power purchase agreement provided by the National Renewable Energy Laboratory, a division of the U.S. Department of Energy.

and (f) amendments to the Governing Documents adopted from time to time. Member agrees that JSC selects the type of equipment and/or technology used to deliver or measure electric service.

2. Delivery of Electricity to Member. Member agrees to purchase from JSC, and JSC shall sell to Member, supplemental electric energy generated by JSC's solar facility ("the System") during the Initial Term and any Additional Term(s) (defined in paragraph 5 below). Electric energy generated by the System will be delivered to Member at the delivery point identified on Exhibit 1 (the "Delivery Point"). Member receives the electric energy generated by the System at the Delivery Point, and risk of loss will pass from JSC to Member at the Delivery Point. Member has the risk of loss from the Delivery Point into the facility and plant occupied by the Member (the "Member's Plant"). Member's primary source of electric energy will continue to come from the municipal utility. Any purchase, sale and/or delivery of electric energy generated by the System prior to the Commercial Operation Date shall be treated as purchase, sale and/or delivery of limited amounts of test energy only and shall not indicate that the System has been put in commercial operation by the purchase, sale and/or delivery of such test energy.

3. Measurement. JSC shall install one or more meter(s), at or immediately before the Delivery Point to measure the energy received by the Member. Such meter shall meet the general commercial standards of the solar photovoltaic industry or the required standard of JSC. JSC shall maintain the meter(s) in accordance with industry standards. As soon as Service becomes available to Member's Premises, Member shall purchase supplemental electricity for use on the Premises from JSC.

4. Billing and Payment.

   a. Monthly Charges. Member shall pay JSC monthly for supplemental renewable energy generated by the System delivered to the Delivery Point. Member agrees to pay the amounts invoiced by JSC for supplemental clean electric energy by the tenth (10th) day of the next month. The amount charged will never exceed an amount that is ninety-five percent (95%) of the difference between what the municipal utility would have charged without JSC's supplemental green energy and what the municipal utility actually did charge for that month. This cap on the amount charged by JSC to its Member applies even where municipal utility rates decrease. On the other hand, if municipal utility rates increase, the increase, if any, on JSC's charge is capped at no more than a five percent (5%) increase above the Member's total electricity charge for the same month in the prior year, after adjusting for this month's actual usage and adjusting for any annual change in the Consumer Price Index. Thus, even if municipal utility rates increase dramatically, the charge to the Member is capped so that year-over-year increases in real dollars (adjusted for changes in the Consumer Price Index) cannot exceed five percent (5%).

   b. Monthly Invoices. JSC shall invoice Member monthly by email or other method agreed to between the parties. Such monthly invoices shall state (i) the amount of electric energy produced by the System and delivered to the Delivery Point, (ii) the rates and charges incurred by Member under this Agreement and (iii) the total amount due from Member.

c. Payment Terms. All amounts due under this Agreement shall be due and payable net twenty (20) days from receipt of invoice. Any undisputed portion of the invoice amount not paid within the twenty (20) day period shall accrue interest at the annual rate of two and one-half percent (2.5%) over the prime rate, as published in the Wall Street Journal (but not to exceed the maximum rate permitted by law).

5. Term and Termination.

a. Initial Term. The initial term ("Initial Term") of this Agreement shall commence on the Commercial Operation Date (as defined below) and continue for thirty (30) years, unless earlier terminated as provided for in this Agreement. The "Commercial Operation Date" is the date JSC gives Member written notice that the System is mechanically complete and capable of providing electric energy to the Delivery Point. Such notice shall be deemed effective unless Member reasonably objects within five (5) days of the date of such notice. Upon Member's request, JSC will give Member copies of certificates of completion or similar documentation from JSC's contractor and any similar agreements required under applicable law. This Agreement is effective as of the Effective Date and Member's failure to allow JSC to provide the electric energy by preventing it from installing the System up to the Delivery Point or otherwise not performing results in termination of this Agreement and damages to JSC. Member agrees that if it signs this Agreement then does not allow the installation of the wiring, smart meter, and related components on its site, then a $10,000.00 design cancellation fee and equipment restocking fee is due from Member to JSC as liquidated damages. Member acknowledges that this pre-installation cancellation fee is reasonably related to actual damages caused by JSC reasonably relying on the executed Agreement.

Member agrees that if it signs this Agreement and allows the installation of the wiring, smart meter, and related components on its site then terminates and/or cancels this Agreement, the Member agrees to pay an early cancellation fee. The Member agrees to give one hundred eighty (180) days notice of its intent to terminate. The early cancellation fee is equal to the installation labor costs of the equipment installed on the Member site, plus the value of the equipment at cost as installed by JSC on Member's site and configured for Member's use; provided, however, the value of the equipment at cost will be depreciated equally over a period of twenty (20) years for the purpose of determining this early cancellation fee. The early cancellation fee is in addition to any damages sustained by JSC as described in Section 15 below. Legal title to the equipment remains with JSC or its lien holders. There are no cancellation fees or early termination damages if Member terminates because JSC fails to provide the supplemental electric energy for ninety (90) consecutive days.

b. Additional Terms. Prior to the end of the Initial Term or of any applicable Additional Term, as defined below, either Party may give the other Party written notice of its desire to extend this Agreement on the terms and conditions set forth herein for an additional five (5) year period. Such notice shall be given, if at all, not more than one hundred twenty (120) and not less than sixty (60) days before the last day of the Initial Term or the then current Additional Term, as applicable. The Party receiving the notice requesting an Additional Term shall respond positively or negatively to that request in writing within thirty (30) days after receipt of the request. Failure to respond within such thirty (30) day period shall be deemed an acceptance of the offer for an Additional Term. If both Parties agree to an Additional Term, the Additional Term shall begin immediately upon the conclusion of the Initial Term or the then current term on the same terms and conditions as set forth in this Agreement. The Parties may agree to more than one Additional Term of five (5) years. If the Party receiving the request for an Additional Term rejects or is deemed to reject the first Party's offer, this Agreement shall terminate at the end of the Initial Term (if the same has not been extended) or the then current Additional Term.

6. Goodwill and Publicity. Neither Party shall use any name, trade name, service mark or trademark of the other Party in any promotional or advertising material without the prior written consent of such other Party. Provided, however, after Member signs this Agreement and within the following twelve (12) months, JSC may make one press release or similar announcement listing the names of all members of JSC. The Parties shall coordinate and cooperate with each other when making public announcements related to the execution and existence of this Agreement, and each Party shall have the right to promptly review, comment upon and approve any publicity materials, press releases or other public statements by the other Party that refer to, or that describe any aspect of, this Agreement. Neither Party shall make any press release or public announcement of the specific terms of this Agreement (except for filings or other statements or releases as may be required by applicable law) without the specific prior written consent of the other Party. Without limiting the generality of the foregoing, all public statements must accurately reflect the rights and obligations of the Parties under this Agreement.

7. Member's Rights and Obligations.

a. Access Rights. Member grants to JSC and to JSC's agents, employees, contractors and assignees an irrevocable non-exclusive license running with the Premises (the "License") for access to, on, over, under and across the Premises for the purposes of (i) installing, constructing, operating, owning, maintaining, accessing, removing and replacing the System; (ii) performing all of JSC's obligations and enforcing all of JSC's rights set forth in this Agreement; and (iii) installing, using and maintaining electric lines and equipment, including inverters and meters necessary to interconnect the System to Member's electric system at the Member's Plant, or for any other purpose that may from time to time be useful or necessary in connection with the construction, installation, operation, maintenance or repair of the System. JSC shall notify Member prior to entering the Member's Plant except in situations where there is imminent risk of damage to persons or property. The term of the License shall continue until the date that is one hundred and twenty (120) days following the date of expiration or termination of this Agreement (the "License Term"). During the License Term, Member shall ensure that JSC's rights under the License and JSC's access to the Member's Plant are preserved and protected. Member shall not interfere with nor shall permit any third parties to interfere with such rights or access. The grant of the License shall survive termination of this Agreement by either Party. At request of JSC, Member shall execute a memorandum of License, and which shall be in a form agreed to by the parties. JSC may, at its sole cost and expense, record such memorandum of License with the register's office.

b. OSHA Compliance. Both Parties shall ensure that all Occupational Safety and Health Act (OSHA) requirements and other similar applicable safety laws or codes are adhered to in their performance under this Agreement.

c. No Alteration to System. Member shall not make any alterations or repairs to the System which could adversely affect the operation and maintenance of the System without JSC's prior written consent. If Member wishes to make such alterations or repairs, Member shall give prior written notice to JSC, setting forth the work to be undertaken (except for emergency repairs, for which notice may be given by telephone), and give JSC the opportunity to advise Member in making such alterations or repairs in a manner that avoids damage to the System, but, notwithstanding any such advice, Member shall be responsible for all damage to the System caused by Member or its contractors. To the extent that temporary disconnection or removal of the System is necessary to perform such alterations or repairs, such work and any replacement of the System after completion of Member's alterations and repairs, shall be done by JSC or its contractors at Member's cost. In addition, if the System is disconnected for more than five (5) days, JSC may ask Member to pay an amount not to exceed the sum of payments that Member would have made to JSC hereunder for electric energy during the time of disconnection that would have been produced by the System during such disconnection or removal based on a daily charge derived from a rolling average of the prior twelve months. All of Member's alterations and repairs will be done in a good and workmanlike manner and in compliance with all applicable laws, codes and permits.

d. Unscheduled Outages. The municipal utility is the primary electric distribution service to Member at the Member's Plant. When the municipal provider experiences an unscheduled service outage, JSC will provide additional electric energy to assist the Member. This additional supplement electrical energy will be prioritized based on the municipal provider's estimates length of the unscheduled outage. The Member and JSC will cooperate in determining the priority of additional supplemental power and the circuits that receive that power in preparation of anticipated unscheduled municipal outages.

e. Liens. Member shall not directly or indirectly cause, create, incur, assume or allow to exist any mortgage, pledge, lien, charge, security interest, encumbrance or other claim of any nature on or with respect to the System or any interest therein. Member shall immediately notify JSC in writing of the existence of any such mortgage, pledge, lien, charge, security interest, encumbrance or other claim, shall promptly cause the same to be discharged and released of record without cost to JSC, and shall indemnify JSC against all costs and expenses (including reasonable attorneys' fees) incurred in discharging and releasing any such mortgage, pledge, lien, charge, security interest, encumbrance or other claim. Notwithstanding anything else herein to the contrary, JSC may grant a lien on the System and may assign, mortgage, pledge or otherwise collaterally assign its interests in this Agreement and the System to any Financing Party.

f. Security. Member shall be responsible for using commercially reasonable efforts to maintain the physical security of the smart meter and other equipment of JSC located at the Member's Plant against known risks and risks that should have been known by Member. Member will not conduct activities on, in or about the Member's Plant that have a reasonable likelihood of causing damage, impairment or otherwise adversely affecting the System.

g. Data Line. Member shall provide JSC a high speed internet data line during the Term to enable JSC to record the electric energy generated by the System. If Member fails to provide such high speed internet data line, or if such line ceases to function and is not repaired, JSC may reasonably estimate the amount of electric energy that was generated and invoice Member for such amount in accordance with Section 4.

h. Breakdown Notice. Member shall notify JSC within twenty-four (24) hours following the discovery by it of (i) any material malfunction in the operation of the System; or (ii) any occurrences that could reasonably be expected to adversely affect the System. Member shall notify JSC immediately upon (i) an interruption in the supply of electrical energy from the System; or (ii) the discovery of an emergency condition respecting the System. Member and JSC shall each designate personnel and establish procedures such that each Party may provide notice of such conditions requiring JSC's repair or alteration at all times, twenty-four (24) hours per day, including weekends and holidays.

8. <u>JSC's Rights and Obligations</u>.

a. Permits and Approvals. JSC, with Member's reasonable cooperation, shall use commercially reasonable efforts to obtain, at its sole cost and expense:

i. any zoning, land use and building permits required to construct, install and operate the System up to the Delivery Point; and

ii. any agreements and approvals necessary in order to connect the System to the Member's electrical system in parallel with the municipal provider's electric distribution system so that no electrical energy back flows into the municipal provider's distribution system.

b. System Repair and Maintenance. JSC shall connect the System to the Member's Plant. JSC will operate and perform all routine and emergency repairs to, and maintenance of, the System at its sole cost and expense, except for any repairs or maintenance resulting from Member's negligence, willful misconduct or breach of this Agreement. JSC shall not be responsible for any work done by others on any part of the System unless JSC authorizes that work in advance in writing. JSC shall not be responsible for any loss, damage, cost or expense arising out of or resulting from improper environmental controls or improper operation or maintenance of the System by anyone other than JSC or JSC's contractors. JSC shall provide Member with reasonable notice prior to accessing the Member's Plant to make standard repairs.

c. Non-Standard System Repair and Maintenance. If JSC incurs incremental costs to maintain the System due to conditions at the Member's Plant or due to the inaccuracy of any information provided by Member and relied upon by JSC, the pricing, schedule and other terms of this Agreement will be equitably adjusted to compensate for any work in excess of normally expected work required to be performed by JSC. In such event, the Parties will negotiate such equitable adjustment in good faith.

d. Breakdown Notice. JSC shall notify Member within twenty-four (24) hours following JSC's discovery of (i) any material malfunction in the operation of the System or (ii) an interruption in the supply of electrical energy from the System. Member and JSC shall each designate personnel and establish procedures such that each Party may provide notice of such conditions requiring JSC's repair or alteration at all times, twenty-four (24) hours per day, including weekends and holidays. Member shall notify JSC immediately upon the discovery of an emergency condition affecting the System.

e. Suspension. Notwithstanding anything to the contrary herein, JSC shall be entitled to suspend delivery of electricity from the System to the Delivery Point for the purpose of maintaining and repairing the System and such suspension of service shall not constitute a breach of this Agreement; provided, that JSC shall use commercially reasonable efforts to minimize any interruption in service to the Member.

f. Use of Contractors and Subcontractors. JSC shall be permitted to use contractors and subcontractors to perform its obligations under this Agreement, provided however, that such contractors and subcontractors shall be duly licensed and shall provide any work in accordance with applicable industry standards. Notwithstanding the foregoing, JSC shall continue to be responsible for the quality of the work performed by its contractors and subcontractors.

g. Liens and Payment of Contractors and Suppliers. JSC shall pay when due all valid charges from all contractors, subcontractors and suppliers supplying goods or services to JSC under this Agreement and shall keep the Member's Plant free and clear of any liens related to such charges, except for those liens which JSC is permitted by law to place on the Member's Plant following non-payment by Member of amounts due under this Agreement. JSC shall indemnify Member for all claims, losses, damages, liabilities and expenses resulting from any liens filed against the Member's Plant in connection with such charges; provided, however, that JSC shall have the right to contest any such lien, so long as it provides a statutory bond or other reasonable assurances of payment that either remove such lien from title to the Member's Plant or that assure that any adverse judgment with respect to such lien will be paid without affecting title to the Member's Plant.

h. No Warranty. NO WARRANTY OR REMEDY, WHETHER STATUTORY, WRITTEN, ORAL, EXPRESS OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR WARRANTIES ARISING FROM COURSE OF DEALING OR USAGE OF TRADE SHALL APPLY. The remedies set forth in this Agreement shall be Member's sole and exclusive remedies for any claim or liability arising out of or in connection with this Agreement, whether arising in contract, tort (including negligence), strict liability or otherwise.

9. Conditions to Obligations.

a. Conditions to JSC's Obligations. JSC's obligations under this Agreement are conditioned on the completion of the following conditions to JSC's reasonable satisfaction on or before 360 days from signing this Agreement (the "Condition Satisfaction Date"):

i. Completion of a physical inspection of the Member's Plant and the property upon which the Member's Plant is located (the "Premises") including, due diligence to confirm the suitability of the Member's Plant and the Premises for the System;

ii. Approval of (A) this Agreement and (B) the Construction Agreement (if any) for the System by JSC's Financing Parties. "Construction Agreement" as used in this subsection means an agreement between JSC and any contractor or subcontractor to install the System or any of its component parts;

iii. Receipt of all necessary zoning, land use and building permits; and

iv. Execution of all other necessary agreements for interconnection of the System to the Member's Plant electrical system and/or the Utility's electric distribution system.

b. Failure of Conditions. If any of the conditions listed in subsection (a) are not satisfied by the Condition Satisfaction Date, the Parties will attempt in good faith to negotiate new dates for the satisfaction of the failed conditions. If the Parties are unable to negotiate new dates then JSC may terminate this Agreement upon ten (10) days written notice to Buyer without liability for costs or damages or triggering a default under this Agreement.

c. Commencement of Construction. JSC's obligation to commence construction of the System is conditioned on JSC's receipt of (A) proof of insurance for all insurance required to be maintained by Member under this Agreement, (B) written confirmation from any person holding a mortgage, lien or other encumbrance over the Premises or the Member's Plant, as applicable, that such person will recognize JSC's rights under this Agreement for as long JSC is not in default hereunder and (C), a signed and notarized original copy of the easement agreement suitable for recording, substantially in the form attached hereto as Exhibit 6 (the "Easement Agreement").

d. Conditions to Member's Obligations. Member's obligations under Section 4(a) are conditioned on the occurrence of the Commercial Operation Date for the System by the Commercial Operation Date.

10. Meter Tampering. If JSC reasonably determines that its meter or other equipment has been tampered with or bypassed, JSC may disconnect service, estimate electric energy consumed as a result and Member agrees to pay for the estimated unmetered energy consumed and the cost of investigating, repairing, replacing or relocating any JSC equipment.

11. System and Member's Plant Damage and Insurance.

a. System and Member's Plant Damage. If the System is damaged or destroyed other than by Member's gross negligence or willful misconduct, JSC shall promptly repair and restore the System to its pre-existing condition; provided, however, that if more than fifty percent (50%) of the System is destroyed during the last five (5) years of the Initial Term or during any Additional Term, JSC shall not be required to restore the System, but may instead terminate this Agreement, unless Member agrees (A) to pay for the cost of such restoration of the System or (B) to purchase the System "AS-IS" at the Fair Market Value of the System.

b. Insurance Coverage. At all times during the Term, JSC and Member shall maintain the following insurance:

i. JSC's Insurance. JSC shall maintain (A) property insurance on the System for the replacement cost thereof, (B) commercial general liability insurance with coverage of at least $1,000,000 per occurrence and $2,000,000 annual aggregate, (C) employer's liability insurance with coverage of at least $1,000,000 and (iv) workers' compensation insurance as required by law.

ii. Member's Insurance. Member shall maintain commercial general liability insurance with coverage of at least $1,000,000 per occurrence and $2,000,000 annual aggregate.

c. Policy Provisions. All insurance policies provided hereunder shall (i) contain a provision whereby the insurer agrees to give the party not providing the insurance (A) not less than ten (10) days written notice before the insurance is cancelled, or terminated as a result of non-payment of premiums, or (B) not less than thirty (30) days written notice before the insurance is otherwise cancelled or terminated, and (ii) be written on an occurrence basis.

d. Certificates. Upon the other Party's request each Party shall deliver the other Party certificates of insurance evidencing the above required coverage. A Party's receipt, review or acceptance of such certificate shall in no way limit or relieve the other Party of the duties and responsibilities to maintain insurance as set forth in this Agreement.

e. Deductibles. Unless and to the extent that a claim is covered by an indemnity set forth in this Agreement, each Party shall be responsible for the payment of its own deductibles.

12. Representations, Warranties and Covenants.

a. General Representations and Warranties. Each Party represents and warrants to the other the following as of the Effective Date:

i. Such Party is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation; the execution, delivery and performance by such Party of this Agreement have been duly authorized by all necessary corporate, partnership or limited liability company action, as applicable, and do not and shall not violate any law; and this Agreement is valid obligation of such Party, enforceable against such Party in accordance with its terms (except as may be limited by applicable bankruptcy, insolvency, reorganization, moratorium and other similar laws now or hereafter in effect relating to creditors' rights generally).

ii. Such Party has obtained all licenses, authorizations, consents and approvals required by any Governmental Authority or other third party and necessary for such Party to own its assets, carry on its business and to execute and deliver this Agreement; and such Party is in compliance with all laws that relate to this Agreement in all material respects.

b. Member's Representations, Warranties and Covenants. Member represents and warrants to JSC the following as of the Effective Date and covenants that throughout the Term:

i. License. Member has title to or a leasehold or other property interest in the

Premises. Member has the full right, power and authority to grant the License contained in Section 8(a). Such grant of the License does not violate any law, ordinance, rule or other governmental restriction applicable to Member or the Member's Plant and is not inconsistent with and will not result in a breach or default under any agreement by which Member is bound or that affects the Member's Plant. If Member does not own the Premises or Member's Plant, Member has obtained all required consents from the owner of the Premises and/or Member's Plant to grant the License and enter into and perform its obligations under this Agreement.

ii. Other Agreements. Neither the execution and delivery of this Agreement by Member nor the performance by Member of any of its obligations under this Agreement conflicts with or will result in a breach or default under any agreement or obligation to which Member is a party or by which Member or the Member's Plant is bound.

iii. Accuracy of Information. All information provided by Member to JSC, as it pertains to the Member's Plant's physical configuration, Member's planned use of the Member's Plant, and Member's estimated electricity requirements, is accurate in all material respects.

13. Indemnification and Limitations of Liability.

a. General. Each Party (the "Indemnifying Party") shall defend, indemnify and hold harmless the other Party and the directors, officers, shareholders, partners, members, agents and employees of such other Party, and the respective affiliates of each thereof (collectively, the "Indemnified Parties"), from and against all loss, damage, expense, liability and other claims, including court costs and reasonable attorneys' fees (collectively, "Liabilities") resulting from any third party actions relating to the breach of any representation or warranty set forth in Section 14 and from injury to or death of persons, and damage to or loss of property to the extent caused by or arising out of the negligent acts or omissions of, or the willful misconduct of, the Indemnifying Party (or its contractors, agents or employees) in connection with this Agreement; provided, however, that nothing herein shall require the Indemnifying Party to indemnify the Indemnified Party for any Liabilities to the extent caused by or arising out of the negligent acts or omissions of, or the willful misconduct of, the Indemnified Party. This Section 13(a) however, shall not apply to liability arising from any form of hazardous substances or other environmental contamination, such matters being addressed exclusively by Section 13(c).

b. Notice and Participation in Third Party Claims. The Indemnified Party shall give the Indemnifying Party written notice with respect to any Liability asserted by a third party (a "Claim"), as soon as possible upon the receipt of information of any possible Claim or of the commencement of such Claim. The Indemnifying Party may assume the defense of any Claim, at its sole cost and expense, with counsel designated by the

Indemnifying Party and reasonably satisfactory to the Indemnified Party. The Indemnified Party may, however, select separate counsel if both Parties are defendants in the Claim and such defense or other form of participation is not reasonably available to the Indemnifying Party. The Indemnifying Party shall pay the reasonable attorneys' fees incurred by such separate counsel until such time as the need for separate counsel expires. The Indemnified Party may also, at the sole cost and expense of the Indemnifying Party, assume the defense of any Claim if the Indemnifying Party fails to assume the defense of the Claim within a reasonable time. Neither Party shall settle any Claim covered by this Section 17(b) unless it has obtained the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed. The Indemnifying Party shall have no liability under this Section 13(b) for any Claim for which such notice is not provided if that the failure to give notice prejudices the Indemnifying Party.

c. Environmental Indemnification. JSC shall indemnify, defend and hold harmless all of Member's Indemnified Parties from and against all Liabilities arising out of or relating to the existence at, on, above, below or near the Premises of any Hazardous Substance (as defined in Section 13(c)(i)) to the extent deposited, spilled or otherwise caused by JSC or any of its contractors or agents. Member shall indemnify, defend and hold harmless all of JSC's Indemnified Parties from and against all Liabilities arising out of or relating to the existence at, on, above, below or near the Premises of any Hazardous Substance, except to the extent deposited, spilled or otherwise caused by JSC or any of its contractors or agents. Each Party shall promptly notify the other Party if it becomes aware of any Hazardous Substance on or about the Premises or the Premises generally or any deposit, spill or release of any Hazardous Substance.

   i. "Hazardous Substance" means any chemical, waste or other substance (A) which now or hereafter becomes defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "extremely hazardous wastes," "restricted hazardous wastes," "toxic substances," "toxic pollutants," "pollution," "pollutants," "regulated substances," or words of similar import under any laws pertaining to the environment, health, safety or welfare, (B) which is declared to be hazardous, toxic, or polluting by any Governmental Authority, (C) exposure to which is now or hereafter prohibited, limited or regulated by any Governmental Authority, (D) the storage, use, handling, disposal or release of which is restricted or regulated by any Governmental Authority, or (E) for which remediation or cleanup is required by any Governmental Authority.

d. Limitations on Liability.

   i. No Consequential Damages. Except with respect to indemnification for third party claims pursuant to this Section 13 and damages that result from the willful misconduct of a Party, neither Party nor its directors, officers, shareholders, partners, members, agents and employees subcontractors or suppliers shall be liable for any indirect, special, incidental, exemplary, or consequential loss or damage of any nature arising out of their performance or non-performance hereunder even if advised of such. The Parties agree that (1) in the event that JSC is required to recapture any Tax Credits or other tax benefits as a result of a breach of this Agreement by Member, such recaptured amount shall be deemed to be direct and not indirect or consequential damages, and (ii) in the event that JSC is retaining the Environmental Attributes produced by the System, and a breach of this Agreement by Member causes JSC to lose the benefit of sales of such Environmental Attributes to third parties, the amount of such lost sales shall be direct and not indirect or consequential damages.

ii. Actual Damages. Except with respect to indemnification for third party claims pursuant to Section 26 and damages that result from the willful misconduct of JSC, JSC's aggregate liability under this Agreement arising out of or in connection with the performance or non-performance of this Agreement shall not exceed the total payments made (or, as applicable, projected to be made) by Member under this Agreement. The provisions of this Section (13)(d)(ii) shall apply whether such liability arises in contract, tort (including negligence), strict liability or otherwise. Any action against JSC must be brought within one (1) year after the cause of action accrues.

14. <u>Confidentiality and Publicity</u>.

a. Confidentiality. If either Party provides confidential information, including business plans, strategies, financial information, proprietary, patented, licensed, copyrighted or trademarked information, and/or technical information regarding the design, operation and maintenance of the System or of Member's business ("Confidential Information") to the other or, if in the course of performing under this Agreement or negotiating this Agreement a Party learns Confidential Information regarding the facilities or plans of the other, the receiving Party shall (a) protect the Confidential Information from disclosure to third parties with the same degree of care accorded its own confidential and proprietary information, and (b) refrain from using such Confidential Information, except in the negotiation and performance of this Agreement, including but not limited to obtaining financing for the System. Notwithstanding the above, a Party may provide such Confidential Information to its, officers, directors, members, managers, employees, agents, contractors and consultants (collectively, "Representatives"), and affiliates, lenders, and potential assignees of this Agreement (provided and on condition that such potential assignees be bound by a written agreement or legal obligation restricting use and disclosure of Confidential Information). Each such recipient of Confidential Information shall be informed by the Party disclosing Confidential Information of its confidential nature and shall be directed to treat such information confidentially and shall agree to abide by these provisions. In any event, each Party shall be liable (with respect to the other

Party) for any breach of this provision by any entity to whom that Party improperly discloses Confidential Information. The terms of this Agreement (but not its execution or existence) shall be considered Confidential Information for purposes of this Section 14(a), except as set forth in Section 14(b). All Confidential Information shall remain the property of the disclosing Party and shall be returned to the disclosing Party or destroyed after the receiving Party's need for it has expired or upon the request of the disclosing Party. Each Party agrees that the disclosing Party would be irreparably injured by a breach of this Section 14(a) by the receiving Party or its Representatives or other person to whom the receiving Party discloses Confidential Information of the disclosing Party and that the disclosing Party may be entitled to equitable relief, including injunctive relief and specific performance, in the event of a breach of the provision of this Section 14(a). To the fullest extent permitted by applicable law, such remedies shall not be deemed to be the exclusive remedies for a breach of this Section 14(a), but shall be in addition to all other remedies available at law or in equity.

b. Permitted Disclosures. Notwithstanding any other provision in this Agreement, neither Party shall be required to hold confidential any information that (i) becomes publicly available other than through the receiving Party, (ii) is required to be disclosed to a Governmental Authority under applicable law or pursuant to a validly issued subpoena (but a receiving Party subject to any such requirement shall promptly notify the disclosing Party of such requirement to the extent permitted by applicable law), (iii) is independently developed by the receiving Party or (iv) becomes available to the receiving Party without restriction from a third party under no obligation of confidentiality. If disclosure of information is required by a Governmental Authority, the disclosing Party shall, to the extent permitted by applicable law, notify the other Party of such required disclosure promptly upon becoming aware of such required disclosure and shall cooperate with the other Party in efforts to limit the disclosure to the maximum extent permitted by law.

15. Default, Remedies and Damages.

a. Default. Any Party that fails to perform its responsibilities as listed below or experiences any of the circumstances listed below shall be deemed to be the "Defaulting Party", the other Party shall be deemed to be the "Non-Defaulting Party", and each event of default shall be a "Default Event":

b. Member agrees to pay any damages, costs, and expenses, including attorney fees and legal expenses, caused by or associated with Member's failure to: (a) pay any amount charged or assessed by JSC for electric Service; (b) comply with the Governing Documents; or (c) provide JSC with truthful, accurate, and complete information.

i. failure of a Party to pay any amount due and payable under this Agreement, other than an amount that is subject to a good faith dispute, within ten (10) days following receipt of written notice from the Non-Defaulting Party of such failure to pay ("Payment Default");

ii. failure of a Party to substantially perform any other material obligation under this Agreement within thirty (30) days following receipt of written notice from the Non-Defaulting Party demanding such cure; provided, that such thirty (30) day cure period shall be extended (but not beyond ninety (90) days) if and to the extent reasonably necessary to cure the Default Event, if (A) the Defaulting Party initiates such cure within the thirty (30) day period and continues such cure to completion and (B) there is no material adverse effect on the Non-Defaulting Party resulting from the failure to cure the Default Event;

iii. if any representation or warranty of a Party proves at any time to have been incorrect in any material respect when made and is material to the transactions contemplated hereby, if the effect of such incorrectness is not cured within thirty (30) days following receipt of written notice from the Non-Defaulting Party demanding such cure;

iv. Member loses its rights to occupy and enjoy the Premises;

v. a Party becomes insolvent or is a party to a bankruptcy, reorganization, insolvency, liquidation, receivership, dissolution, winding-up or relief of debtors, or any general assignment for the benefit of creditors or other similar arrangement or any event occurs or proceedings are taken in any jurisdiction with respect to the Party which has a similar effect, and, if any such bankruptcy or other proceedings were initiated by a third party, if such proceedings have not been dismissed within sixty (60) days following receipt of a written notice from the Non-Defaulting Party demanding such cure; or

vi. Member prevents JSC from installing the System or otherwise failing to perform in a way that prevents the delivery of electric energy from the System. Such Default Event shall not excuse Member's obligations to make payments that otherwise would have been due under this Agreement.

c. Remedies.

i. Remedies for Payment Default. If a Payment Default occurs, the Non-Defaulting Party may suspend performance of its obligations under this Agreement. Further, the Non-Defaulting Party may (A) at any time during the continuation of the Default Event, terminate this Agreement upon five (5) days prior written notice to the Defaulting Party, and (B) pursue any remedy under this Agreement, at law or in equity, including an action for damages.

ii. Remedies for Other Defaults. On the occurrence of a Default Event other than a Payment Default, the Non-Defaulting Party may (A) at any time during the continuation of the Default Event, terminate this Agreement or suspend its performance of its obligations under this Agreement, upon five (5) days prior written notice to the Defaulting Party, and (B) pursue any remedy under this Agreement, at law or in equity, including an action for damages. Nothing herein shall limit either Party's right to collect damages upon the occurrence of a breach or a default by the other Party that does not become a Default Event. If Member terminates this contract without cause prior to commencement of System installation on the Member's premises, a $10,000.00 design cancellation fee and equipment restocking fee applies as decribed in Section 5(a) above in addition to any other remedy available to JSC.

iii. Damages Upon Termination by Default. Upon a termination of this Agreement by the Non-Defaulting Party as a result of a Default Event by the Defaulting Party, the Defaulting Party shall pay a Termination Payment to the Non-Defaulting Party determined as follows (the "Termination Payment"):

d. Obligations Following Termination. If a Non-Defaulting Party terminates this Agreement pursuant to this Section 13(b), then following such termination, JSC shall, at the sole cost and expense of the Defaulting Party, remove the equipment (except for mounting pads and support structures) constituting the System. The Non-Defaulting Party shall take all commercially reasonable efforts to mitigate its damages as the result of a Default Event.

16. Removal of System at Expiration. Upon the expiration or earlier termination of this Agreement (provided Member does not exercise its purchase option), JSC shall, at its expense, remove all of its tangible property comprising the System from the Member's Plant on a mutually convenient date, but in no event later than one hundred twenty (120) days after the expiration of the Term. Excluding ordinary wear and tear, the Member's Plant shall be returned to its original condition including the removal of System mounting pads or other support structures. In no case shall JSC's removal of the System affect the integrity of Member's roof, which shall be as leak proof as it was prior to removal of the System and shall be flashed and/or patched to existing roof specifications. JSC shall leave the Member's Plant in neat and clean order. If JSC fails to remove or commence substantial efforts to remove the System by such agreed upon date, Member shall have the right, at its option, to remove the System to a public warehouse and restore the Member's Plant to its original condition (other than ordinary wear and tear) at JSC's cost. Member shall provide sufficient space for the temporary storage and staging of tools, materials and equipment and for the parking of construction crew vehicles and temporary construction trailers and facilities reasonably necessary during System removal.

17. Miscellaneous

a. Member agrees to comply with all governmental rules and regulations and all electric industry standards and requirements applicable to Service to Member, including, the National Electric Safety Code, applicable state or local statutes, codes or ordinances and all similar regulations or requirements necessary to for JSC to safely, efficiently, and reliably provide Service to Member and/or to other persons. Member specifically agrees that the ownership, operation, maintenance, repair, use, and removal of any electric generating equipment by Member that is connected to any transformer, line, or other JSC equipment or property, shall be subject to applicable safety rules.

b. Change in Law. "Change in Law" means (i) the enactment, adoption, promulgation, modification or repeal after the Effective Date of any applicable law or regulation; (ii) the imposition of any material conditions on the issuance or renewal of any applicable permit after the Effective Date of this Agreement (notwithstanding the general requirements contained in any applicable Permit at the time of application or issue to comply with future laws, ordinances, codes, rules, regulations or similar legislation), or (iii) a change in any utility rate schedule or tariff approved by any Governmental Authority which in the case of any of (i), (ii) or (iii), establishes requirements affecting owning, supplying, constructing, installing, operating or maintaining the System, or other performance of the JSC's obligations hereunder and which has a material adverse effect on the cost to JSC of performing such obligations; provided, that a change in federal, state, county or any other tax law after the Effective Date of this Agreement shall not be a Change in Law pursuant to this Agreement.

If any Change in Law occurs that has a material adverse effect on the cost to JSC of performing its obligations under this Agreement, then the Parties shall, within thirty (30) days following receipt by Member from JSC of notice of such Change in Law, meet and attempt in good faith to negotiate amendments to this Agreement as are reasonably necessary to preserve the economic value of this Agreement to both Parties. If the Parties are unable to agree upon such amendments within such thirty (30) day period, then JSC shall have the right to terminate this Agreement without further liability to either Party except with respect to payment of amounts accrued prior to termination.

c. Environmental Attributes. Member acknowledges that on todays market JSC can sell the Renewable Energy Credits on the open market. Unless otherwise agreed, Member is the owner of all Environmental Attributes and Environmental Incentives and is entitled to the benefit of the Renewable Energy Credits (excluding the Investment Tax Credit), and Member's purchase of electricity under this Agreement includes all Environmental Attributes. Member shall cooperate with JSC in obtaining, securing and transferring all Environmental Attributes and Environmental Incentives and the benefit of all Renewable Energy Credits, including by using the electric energy generated by the System in a manner necessary to qualify for such available Environmental Attributes, Environmental Incentives and Renewable Energy Credits. JSC shall not be obligated to incur any out-of-pocket costs or expenses in connection with such actions unless reimbursed by Member. If any Environmental Incentives are paid directly to JSC, JSC shall immediately pay such amounts over to Member. To avoid any conflicts with fair trade rules regarding claims of solar or renewable energy use, Member, if engaged in commerce and/or trade, shall submit to JSC for approval any press releases regarding Member's use of solar or renewable energy. Approval shall not be unreasonably withheld, and JSC's review and approval shall be made in a timely manner to permit Member's timely publication.

"Environmental Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the System, the production of electrical energy from the System and its displacement of conventional energy generation, including (a) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (b) any avoided emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere; and (c) the reporting rights related to these avoided emissions, such as Green Tag Reporting Rights and Renewable Energy Credits. Green Tag Reporting Rights are the right of a party to report the ownership of accumulated Green Tags in compliance with federal or state law, if applicable, and to a federal or state agency or any other party, and include Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local law, regulation or bill, and international or foreign emissions trading program. Environmental Attributes do not include Environmental Incentives and Renewable Energy Credits. Member and JSC shall file all tax returns in a manner consistent with this Section 5. Without limiting the generality of the foregoing, Environmental Attributes include carbon trading credits, renewable energy credits or certificates, emissions reduction credits, emissions allowances, green tags tradable renewable credits and Green-e® products.

d. Force Majeure.

   i. "Force Majeure" means any event or circumstances beyond the reasonable control of and without the fault or negligence of the Party claiming Force Majeure. It shall include, without limitation, failure or interruption of the production, delivery or acceptance of electricity due to: an act of god; war (declared or undeclared); sabotage; riot; insurrection; civil unrest or disturbance; military or guerilla action; terrorism; economic sanction or embargo; civil strike, work stoppage, slow-down, or lock-out; explosion; fire; earthquake; abnormal weather condition or actions of the elements; hurricane; flood; lightning; wind; drought; the binding order of any Governmental Authority (provided that such order has been resisted in good faith by all reasonable legal means); the failure to act on the part of any Governmental Authority (provided that such action has been timely requested and diligently pursued); unavailability of electricity from the utility grid, equipment, supplies or products (but not to the extent that any such availability of any of the foregoing results from the failure of the Party claiming Force Majeure to have exercised reasonable diligence); and failure of equipment not utilized by or under the control of the Party claiming Force Majeure.

ii. Except as otherwise expressly provided to the contrary in this Agreement, if either Party is rendered wholly or partly unable to timely perform its obligations under this Agreement because of a Force Majeure event, that Party shall be excused from the performance affected by the Force Majeure event (but only to the extent so affected) and the time for performing such excused obligations shall be extended as reasonably necessary; provided, that: (i) the Party affected by such Force Majeure event, as soon as reasonably practicable after obtaining knowledge of the occurrence of the claimed Force Majeure event, gives the other Party prompt oral notice, followed by a written notice reasonably describing the event; (ii) the suspension of or extension of time for performance is of no greater scope and of no longer duration than is required by the Force Majeure event; and (iii) the Party affected by such Force Majeure event uses all reasonable efforts to mitigate or remedy its inability to perform as soon as reasonably possible. The Term shall be extended day for day for each day performance is suspended due to a Force Majeure event.

iii. Notwithstanding anything herein to the contrary, the obligation to make any payment due under this Agreement shall not be excused by a Force Majeure event that solely impacts Member's ability to make payment.

iv. If a Force Majeure event continues for a period of thirty (30) days or more within a twelve (12) month period and prevents a material part of the performance by a Party hereunder, then at any time during the continuation of the Force Majeure event, the Party not claiming the Force Majeure shall have the right to terminate this Agreement without fault or further liability to either Party (except for amounts accrued but unpaid).

e. This Agreement shall be governed by and interpreted under the laws of the State of Tennessee. In the event a suit is commenced to enforce this Agreement, venue may be laid, at the option of JSC in Madison County, Tennessee.

f. Waiver. The failure of either party to enforce, or the delay by either party in enforcing, any of its rights hereunder shall not constitute a continuing waiver or a modification of this Agreement and either party may, within the time provided by application of law, commence appropriate legal proceedings to enforce any or all of such rights.

g. Assignment and Financing.

i. Assignment. This Agreement may not be assigned in whole or in part by either Party without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, JSC may, without the prior written consent of Member, (i) assign, mortgage, pledge or otherwise collaterally assign its interests in this Agreement and the System to any Financing Party, (ii) directly or indirectly assign this Agreement and the System to an affiliate or subsidiary of JSC, (iii) assign this Agreement and the System to any entity through which JSC is obtaining financing or capital for the System and (iv) assign this Agreement and the System to any person succeeding to all or substantially all of the assets of JSC (provided that JSC shall be released from liability hereunder as a result of any of the foregoing permitted assignments only upon assumption of JSC's obligations hereunder by the assignee). In the event of any such assignment, the JSC shall be released from all its liabilities and other obligations under this Agreement. However, any assignment of JSC's right and/or obligations under this Agreement, shall not result in any change to Member's rights and obligations under this Agreement. Member's consent to any other assignment shall not be unreasonably withheld if Member has been provided with reasonable proof that the proposed assignee (x) has comparable experience in operating and maintaining photovoltaic solar systems comparable to the System and providing services comparable to those contemplated by this Agreement and (y) has the financial capability to maintain the System and provide the services contemplated by this Agreement in the manner required by this Agreement. This Agreement shall be binding on and inure to the benefit of the successors and permitted assignees.

ii. Financing. The Parties acknowledge that JSC may obtain construction and long-term financing or other credit support from one or more Financing Parties. "Financing Parties" means person or persons providing construction or permanent financing to JSC in connection with construction, ownership, operation and maintenance of the System, or if applicable, means, if applicable, any person to whom JSC has transferred the ownership interest in the System, subject to a leaseback of the System from such person. Both Parties agree in good faith to consider and to negotiate changes or additions to this Agreement that may be reasonably requested by the Financing Parties; provided, that such changes do not alter the fundamental economic terms of this Agreement.

iii. Successor Servicing. The Parties further acknowledge that in connection with any construction or long term financing or other credit support provided to JSC or its affiliates by Financing Parties, that such Financing Parties may require that JSC or its affiliates appoint a third party to act as backup or successor provider of operation and maintenance services with respect to the System and/or administrative services with respect to this Agreement (the "Successor Provider"). Member agrees to accept performance from any Successor Provider so appointed so long as such Successor Provider performs in accordance with the terms of this Agreement.

h. Arbitration and Attorneys' Fees. Any dispute arising from or relating to this Agreement shall be arbitrated in Jackson, Tennessee. The arbitration shall be administered by JAMS in accordance with its Comprehensive Arbitration Rules and Procedures, and judgment on any award may be entered in any court of competent jurisdiction. If the Parties agree, a mediator may be consulted prior to arbitration. The prevailing party in any dispute arising out of this Agreement shall be entitled to reasonable attorneys' fees and costs.

i. Notices. All notices under this Agreement shall be in writing and shall be by personal delivery, facsimile transmission, electronic mail, overnight courier, or regular, certified, or registered mail, return receipt requested, and deemed received upon personal delivery, acknowledgment of receipt of electronic transmission, the promised delivery date after deposit with overnight courier, or five (5) days after deposit in the mail. Notices shall be sent to the person identified in this Agreement at the addresses set forth in this Agreement or such other address as either party may specify in writing. Each party shall deem a document faxed, emailed or electronically sent in PDF form to it as an original document.

j. Survival. Provisions of this Agreement that should reasonably be considered to survive termination of this Agreement shall survive. For the avoidance of doubt, surviving provisions shall include, without limitation, Section 6 (Goodwill and Publicity), Section 7 (Member's Rights and Obligations), Section 8 (JSC's Rights and Obligations), Section 11 (System Damage and Insurance), Section 12 (Representations, Warranties and Covenants), Section 13 (Indemnification), Section 14 (Confidentiality and Publicity), and Section 15 (Default, Remedies and Damages).

k. Further Assurances. Each of the Parties hereto agree to provide such information, execute and deliver any instruments and documents and to take such other actions as may be necessary or reasonably requested by the other Party which are not inconsistent with the provisions of this Agreement and which do not involve the assumptions of obligations other than those provided for in this Agreement, to give full effect to this Agreement and to carry out the intent of this Agreement.

l. Non-Dedication of Facilities. Nothing herein shall be construed as the dedication by either Party of its facilities or equipment to the public or any part thereof. Neither Party shall knowingly take any action that would subject the other Party, or other Party's facilities or equipment, to the jurisdiction of any Governmental Authority as a public utility or similar entity.

m. Estoppel. Either Party hereto, without charge, at any time and from time to time, within five (5) business days after receipt of a written request by the other party hereto, shall deliver a written instrument, duly executed, certifying to such requesting party, or any other person specified by such requesting Party: (i) that this Agreement is unmodified and in full force and effect, or if there has been any modification, that the same is in full force and effect as so modified, and identifying any such modification; (ii) whether or not to the knowledge of any such party there are then existing any offsets or defenses in favor of such party against enforcement of any of the terms, covenants and conditions of this Agreement and, if so, specifying the same and also whether or not to the knowledge of such party the other party has observed and performed all of the terms, covenants and conditions on its part to be observed and performed, and if not, specifying the same; and (iii) such other information as may be reasonably requested by the requesting Party. Any written instrument given hereunder may be relied upon by the recipient of such instrument, except to the extent the recipient has actual knowledge of facts contained in the certificate.

n. Service Contract. The Parties intend this Agreement to be a "service contract" within the meaning of Section 7701(e)(3) of the Internal Revenue Code of 1986. Member will not take the position on any tax return or in any other filings suggesting that it is anything other than a purchase of electricity from the System.

o. Full Agreement, Modification, Invalidity, Counterparts, Captions. This Agreement, together with any Exhibits, completely and exclusively states the agreement of the Parties regarding its subject matter and supersedes all prior proposals, agreements, or other communications between the Parties, oral or written, regarding its subject matter. This Agreement may be modified only by a writing signed by both Parties. If any provision of this Agreement is found unenforceable or invalid, such unenforceability or invalidity shall not render this Agreement unenforceable or invalid as a whole. In such event, such provision shall be changed and interpreted so as to best accomplish the objectives of such unenforceable or invalid provision within the limits of applicable law. This Agreement may be executed in any number of separate counterparts and each counterpart shall be considered an original and together shall comprise the same Agreement. The captions or headings in this Agreement are strictly for convenience and shall not be considered in interpreting this Agreement.

p. Forward Contract. The transaction contemplated under this Agreement constitutes a "forward contract" within the meaning of the United States Bankruptcy Code, and the Parties further acknowledge and agree that each Party is a "forward contract merchant" within the meaning of the United States Bankruptcy Code.

q. Bonding.

   i. Performance bond liability. Any performance bond issued for a site or system will cease one (1) year from the completion of construction. If a warranty or guarantee is provided under the terms of this Agreement, the balance of any warranty or guarantee beyond one year term of the applicable performance bond shall continue to be guaranteed solely by JSC under the terms of this Agreement. The performance bond does not guarantee any property restorative requirements.

   ii. Payment bond liability. Any payment bond issued will cease at the termination of any time required by law.

iii. Performance Guarantee. Neither payment bonds, whether for labor or materials, nor performance bonds are applicable to any specified performance guarantee.

IN WITNESS WHEREOF, the parties hereto have affixed their hands and seal the date first shown above.

| JACKSON SUSTAINABILITY COOPERATIVE: | MEMBER: |
|---|---|
| By:______________________________ | By:______________________________ |
| Denny Emberling, President | Its: ______________________________ |
| Date:______________________________ | Date:______________________________ |

# EXHIBIT 5

# Power Contract

SEE Supp 21, 10/1/89

TV-47356A

See TV-47356A Supp. No. 28 6/21/91

See TV-47356A, S. 29, 3-1-92

SEE Supp 46, 3/1/96.

See Supp. No. 48, 10/2/96

**POWER CONTRACT**
**Between**
**TENNESSEE VALLEY AUTHORITY**
**And**
**CITY OF JACKSON, TENNESSEE**

THIS CONTRACT, made and entered into as of the 12th day of August, 1977, by and between TENNESSEE VALLEY AUTHORITY (hereinafter called "TVA"), a corporation created and existing under and by virtue of the Tennessee Valley Authority Act of 1933, as amended (hereinafter called "TVA Act"), and CITY OF JACKSON (hereinafter called "Municipality"), a municipal corporation duly created, organized, and existing under and by virtue of the laws of the State of Tennessee;

W I T N E S S E T H:

WHEREAS, the TVA Act authorizes TVA to sell the power generated by it and not used in its operations to States, counties, municipalities, corporations, partnerships, or individuals according to the policies therein set forth; and

WHEREAS, the TVA Act provides that the sale of such power shall be primarily for the benefit of the people of the section as a whole and particularly the domestic and rural consumers, to whom it is desired to make power available at the lowest possible rates; and

WHEREAS, Municipality owns an electric system which is managed and operated by a board of utility commissioners (hereinafter called "Board") and in the operation thereof is presently purchasing and desires to continue to purchase its entire power requirements from TVA; and

WHEREAS, the parties wish to enter into a new contract to replace their present power contract;

NOW, THEREFORE, in consideration of the mutual promises herein contained and subject to the provisions of the TVA Act, the parties agree as follows:

1. Purpose of Contract. It is hereby recognized and declared that, pursuant to the obligations imposed by the TVA Act, Municipality's operation of a municipal electric system and TVA's wholesale service thereto are primarily for the benefit of the consumers of electricity. Toward that end, Municipality agrees that the electric system shall be operated on a nonprofit basis, and that electric system funds and accounts shall not be mingled with other funds or accounts of Municipality. Municipality may, as hereinafter provided, receive from the operation thereof for the benefit of its general funds only an amount in lieu of taxes representing a fair share of the cost of government properly to be borne by such system. In accordance with these principles, which are mutually recognized as of the essence of this contract, Municipality agrees that the electric system shall be operated and the system's financial accounts and affairs shall be maintained in full and strict accordance with the provisions of this contract.

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2. Power Supply.

(a) Subject to the other provisions of this contract, TVA shall produce and deliver to Municipality at the delivery point or points specified in or hereafter established under section 3 hereof and Municipality shall take and distribute the electric power required for service to Municipality's customers. Municipality shall keep TVA currently informed of any important developments affecting its probable future loads or service arrangements. TVA shall take account of all available information in making its forecasts of the loads of Municipality and of TVA's other customers. TVA shall make every reasonable effort to increase the generating capacity of its system and to provide the transmission facilities required to deliver the output thereof so as to be in a position to supply additional power therefrom when and to the extent needed to meet increases in their loads.

(b) Municipality shall be entitled to use the power made available hereunder to serve all consumers to whom the resale rate schedules specified in section 5(b) hereof are applicable except those TVA is entitled to serve directly, as provided below. TVA shall be entitled to serve directly any consumer to whom said resale rate schedules are not applicable, any federal installations excepting those with loads less than 5,000 kilowatts served from a general delivery point, and any consumer whose energy requirements in any month are more than 10 million kilowatthours plus the amount of energy, if any, delivered by Municipality to residential consumers under billings for the preceding June and received from TVA at the delivery point through which Municipality would receive the energy for such consumer if it were served by Municipality. The supply of power by TVA to Municipality for resale to any consumer which has a supply of 5,000 kilowatts or more of power other than that furnished by Municipality under said resale rate schedules, and the contract for such resale between Municipality and such consumer, shall be subject to such special arrangements as TVA may reasonably require. Nothing herein shall be construed as preventing Municipality and TVA from agreeing upon special arrangements for service to any consumer.

(c) It is recognized that from time to time there may be a consumer served by one party hereto which, because of changed conditions, may become a consumer which the other party is entitled to serve under the provisions of subsection (b) of this section. In any such case the parties hereto, unless otherwise agreed, shall make such arrangements (including making appropriate allowance for any otherwise unrecoverable investment made to serve such consumer) as may be necessary to transfer as soon as practicable such consumer to the party entitled to serve the consumer hereunder and the party originally serving said consumer shall cooperate in every way with the party entitled to serve the consumer in making arrangements for the latter to undertake such service including, without limitation, releasing the consumer from any then existing power contract from and after the effective date for initiating service under any contract between such consumer and the party entitled to serve it.

(d) Municipality shall keep TVA informed of any prospective developments affecting any individual load which uses or will use 5,000 kilowatts or more. As soon as practicable after receipt of information from Municipality regarding the prospective addition of, or increase in, any load of 5,000 kilowatts or larger which Municipality would be entitled to serve hereunder, TVA shall notify Municipality of the time schedule upon which the additional power required for such service could be made available to Municipality at the wholesale rates then in effect hereunder and, upon request, of any terms under which it could supply any power in advance of said schedule. Municipality shall not take and deliver such additional power for said load in advance of or in amounts larger than specified in said schedule except to the extent that it has made special arrangements with TVA to do so. TVA, by notice in writing to Municipality, may change the designated amount of 5,000 kilowatts appearing in this subsection (d) to such other amount as TVA deems necessary.

(e) The area limitations in the first three paragraphs of subsection (a) of section 15d of the TVA Act are incorporated herein by reference as fully as though set out herein, and this contract shall not be construed as permitting any arrangement by Municipality which would be inconsistent with those limitations.

(f) Notwithstanding any other provision of this section, TVA may, as a condition precedent to TVA's obligation to make power available, require Municipality to provide such assurances of revenue to TVA as in TVA's judgment may be necessary to justify the reservation, alteration, or installation by TVA of additional generation, transmission, or transformation facilities for the purpose of supplying power to Municipality.

3. Delivery and Receipt of Power. The power to be supplied hereunder shall be delivered at the delivery points designated below and, under normal operating conditions, shall be within commercial limits of 60 hertz and within 3 percent above or below the normal wholesale delivery voltage specified below for each delivery point; provided, however, that any normal wholesale delivery voltage of 46 kV or higher specified below may be changed by TVA from time to time upon notice to Municipality to a voltage level not more than 5 percent higher or lower than the voltage so specified. Substation transformers with a high-side voltage rating of 46 kV or above will be equipped with taps or other suitable means for adjusting for the changes in normal voltage set forth herein. The operating representatives of the parties may by mutual agreement provide for variations in wholesale delivery voltage other than those provided for herein when in their judgment such variations are necessary or desirable.

161-KV SIDE of the CARRIAGE HOUSE 161-KV SUBSTATION 161,000 (SUPP. 47, 6/21/96)

| Delivery Point | Normal Wholesale Delivery Voltage |
|---|---|
| 161-KV bus connection at TVA's Madison West 161-KV Switching Station | 161,000, dated 5/6/98, supp. 55 |
| 46-kV side of TVA's South Jackson 161-kV Substation | 46,000 |

*

It is recognized that load growth and development and the maintenance of high quality service in Municipality's area may require new delivery points from time to time. Such new delivery points will be established by mutual agreement. In reaching such agreement Municipality and TVA shall be guided by the policy of providing the most economical of the practical combinations of transmission and distribution facilities, considering all pertinent factors, including any unusual factors applicable to the area involved.

*Point of connection of [illegible] [illegible] [illegible] [illegible] 161,000

(See S#18, dated 4-8-88)

[illegible]

Neither party shall be responsible for installing at any delivery point equipment for the protection of the other's facilities, or for damages to the other's system resulting from the failure of its own protective devices, but each party agrees so to design, construct, and operate its system as not to cause undue hazards to the other's system.

4. Wholesale Rate. Attached hereto and made a part hereof is a "Schedule of Rates and Charges" wherein Municipality is referred to as "Distributor." Subject to the other provisions of this contract, Municipality shall pay for the power and energy supplied by TVA in accordance with the provisions of Wholesale Power Rate--Schedule WS.

The payments to be made hereunder shall be made solely and exclusively from the revenues of the electric system and shall not be a charge upon Municipality's general funds.

5. Resale Rates. In distributing electric energy in the area served by Municipality, the parties agree as follows:

(a) Municipality agrees that the power purchased hereunder shall be sold and distributed to the ultimate consumer without discrimination among consumers of the same class, and that no discriminatory rate, rebate, or other special concession will be made or given to any consumer, directly or indirectly.

(b) Municipality agrees to serve consumers, including all municipal and governmental customers and departments, at and in accordance with the rates, charges, and provisions set forth for the several classes thereof in Schedules RS-10, GS-10, and LS of said Schedule of Rates and Charges, and not to depart therefrom except as the parties hereto may agree upon surcharges, special minimum bills, or additional resale schedules for special classes of consumers or special uses of electric energy, and except as provided in subsection (c) next following.

For the purpose of uniform application, within the classes of consumers, of the provisions of the paragraph entitled "Payment" of said resale schedules, Municipality shall designate in its standard policy a period of not less than 10 days nor more than 20 days after date of the bill during which period the bill is payable as computed by application of the charges for service under the appropriate resale schedule, and shall further designate in said policy the percentage or percentages, if any, not to exceed 10 percent of the bill, computed as above provided, which will be added to the bill as additional charges for payment after the period so designated.

(c) If the rates and charges provided for in said resale schedules do not produce revenues sufficient to provide for the operation and maintenance of the electric system on a self-supporting and financially sound basis, including requirements for interest and principal payments on indebtedness incurred or assumed by Municipality for the acquisition, extension, or improvement of the electric system (hereinafter called "System Indebtedness"), Board and TVA shall agree upon, and Municipality shall put into effect promptly, such changes in rates and charges as will provide the increased revenues necessary to place the system upon a self-supporting and financially sound basis. If the rates and charges in effect at any time provide revenues that are more than sufficient for such purposes, as more particularly described in section 6 hereof, Board and TVA shall agree upon a reduction in said rates and charges, and Municipality shall promptly put such reduced rates and charges into effect.

6. Use of Revenues.

(a) Municipality agrees to use the gross revenues from electric operations for the following purposes:

(1) Current electric system operating expenses, including salaries, wages, cost of materials and supplies, power at wholesale, and insurance;

(2) Current payments of interest on System Indebtedness, and the payment of principal amounts, including sinking fund payments, when due;

(3) From any remaining revenues, reasonable reserves for renewals, replacements, and contingencies; and cash working capital adequate to cover operating expenses for a reasonable number of weeks; and

(4) From any revenues then remaining, tax equivalent payments into Municipality's general funds, as more particularly provided in section 2 of the Schedule of Terms and Conditions hereinafter referred to.

(b) All revenues remaining over and above the requirements described in subsection (a) of this section shall be considered surplus revenues and may be used for new electric system construction or the retirement of System Indebtedness prior to maturity; provided, however, that resale rates and charges shall be reduced from time to time to the lowest practicable levels considering such factors as future circumstances affecting the probable level of earnings, the need or desirability of financing a reasonable share of new construction from such surplus revenues, and fluctuations in debt service requirements.

7. Equal Opportunity. It is the policy of the federal government to provide equal employment opportunity, and in furtherance of that policy, it is the policy of TVA, as an agency of the federal government, to encourage equal employment opportunity in the various aspects of its programs, including the sale and distribution of TVA power. Accordingly, during the term of this power contract:

(a) Municipality will not discriminate against any employee or applicant for employment with its electric system because of race, color, religion, sex, or national origin. Municipality will take such affirmative action as is necessary to insure that all applicants are considered for employment and that all employees are treated in all aspects of employment without regard to their race, color, religion, sex, or national origin.

(b) Municipality will, in all solicitations or advertisements for employees placed by or on behalf of the electric system, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) Municipality will cooperate and participate with TVA in the development of training and apprenticeship programs which will provide opportunities for applicants and prospective applicants for employment with the electric system to become qualified for such employment, and such cooperation will include access by authorized TVA representatives to its electric system's books, records, and accounts pertaining to training, apprenticeship, recruitment, and employment practices and procedures.

8. Terms and Conditions. Certain additional provisions of this contract are set forth in a "Schedule of Terms and Conditions," which is attached hereto and made a part hereof.

9. Rules and Regulations. Municipality hereby adopts the "Schedule of Rules and Regulations" attached hereto, in which Municipality is referred to as "Distributor." Such Rules and Regulations may be amended, supplemented, or repealed by Municipality at any time upon 30 days' written notice to TVA setting forth the nature of and reason for the proposed change. No change shall be made in said schedule, however, which is in violation of or inconsistent with any of the provisions of this contract.

10. Use of Lines for Transmission Purposes. TVA is hereby granted the privilege of using any electric lines of Municipality, to the extent of their capacity in excess of the requirements of Municipality, for the purpose of transmitting electric energy between adjoining portions of TVA's facilities or to other customers of TVA. TVA shall be obligated to pay Municipality the additional cost, including any additional fixed charges and operating and maintenance costs, imposed on Municipality by permitting use of its facilities to serve other customers of TVA, and to indemnify and save harmless Municipality from any damage or injury caused by TVA's exercise of such use.

11. Waiver of Defaults. Any waiver at any time by either party hereto of its rights with respect to any default of the other party or with respect to any other matter arising in connection with this contract shall not be considered a waiver with respect to any subsequent default or matter.

12. Transfer of Contract. Neither this contract nor any interest herein shall be transferable or assignable by Municipality without the consent of TVA.

13. Restriction of Benefits. No member of or delegate to Congress or resident commissioner or any agent or employee of TVA shall be admitted to any share or part of this contract or to any benefit to arise therefrom. However, nothing contained in this section shall be construed to extend to any citizen of Municipality under arrangements for the general benefit of Municipality.

14. Termination of Existing Contracts. It is hereby agreed that the power contract dated April 1, 1957, and numbered TV-19330A, as supplemented and amended, between the parties is terminated as of the effective date of this contract; provided, however, that nothing herein contained shall be construed as

effecting the termination of (1) Lease-Purchase Agreement TV-19330A, Supplement No. 12, dated November 30, 1976, between the parties hereto relative to the lease and eventual purchase by Municipality of sections of TVA's South Jackson-Humboldt and South Jackson-Morris 46-kV Transmission Lines and (2) section 3 of Agreement TV-19330A, Supplement No. 10, dated December 28, 1976, between the parties hereto relative to application of a monthly facilities rental credit to billings under Wholesale Power Rate—Schedule WS, it being the intention of the parties that each of said agreements, or portions thereof, shall remain in full force and effect for the term of this contract unless sooner terminated in accordance with the provisions of each agreement. All references in said agreements or portions thereof, to the power contract dated April 1, 1957, shall be deemed to refer to this contract.

15. Term of Contract. This contract shall become effective as of September 1, 1977, and shall continue in effect for 20 years from said date, subject to termination by either party, effective not earlier than 10 years from said date, on not less than four years' prior written notice. If Municipality should give notice of termination hereunder, TVA shall be under no obligation from the date of receipt of such notice to make or complete any additions to or changes in any transformation or transmission facilities for service to Municipality unless Municipality agrees to reimburse TVA for its nonrecoverable costs in connection with the making or completion of such additions or changes.

IN WITNESS WHEREOF, the parties hereto have caused this contract to be executed by their duly authorized officers, as of the day and year first above written.

Approved by TVA
Board of Directors
AUG 25 1977
s/ M.E.
Assistant Secretary

Attest: (SEAL) — TENNESSEE VALLEY AUTHORITY

s/ Madge Evans
Assistant Secretary

By s/ Lynn Seeber
General Manager

s/ JMc
Law

Attest: — CITY OF JACKSON, TENNESSEE
By Board of Utility Commissioners

s/ Joe H. Exum
(Title) General Manager

By s/ James W. Hoppers
Chairman

Attest: — Approved:
CITY OF JACKSON, TENNESSEE

s/ James A. Wolfe, Jr.
(Title) City Recorder

By s/ Robert D. Conger
Mayor

# Outdoor Lighting

OUTDOOR LIGHTING RATE—SCHEDULE LS
(October 1976)

Availability

Available for service to street and park lighting systems, traffic signal systems, athletic field lighting installations (during prescribed use-period), and outdoor lighting for individual customers.

Service under this schedule is for a term of not less than one year.

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PART A—CHARGES FOR STREET AND PARK LIGHTING SYSTEMS, TRAFFIC SIGNAL SYSTEMS, AND ATHLETIC FIELD LIGHTING INSTALLATIONS

I. Energy Charge: 1.984 cents per kilowatthour as increased or decreased in accordance with Appendix I to the Schedule of Rates and Charges

Adjustment

The customer's bill for each month shall be increased or decreased in accordance with the current Adjustment Addendum published by TVA.

II. Investment Charge

The annual investment charge shall be 10 percent of the installed cost to Distributor's electric system of the facilities devoted to street and park lighting service specified in this Part A. Such installed cost shall be recomputed on July 1 of each year, or more often if substantial changes in the facilities are made. Each month, one-twelfth of the then total annual investment charge shall be billed to the customer. If any part of the facilities has not been provided at the electric system's expense or if the installed cost of any portion thereof is reflected on the books of another municipality or agency or department, the annual investment charge shall be adjusted to reflect properly the remaining cost to be borne by the electric system.

Traffic signal systems and athletic field lighting installations shall be provided, owned, and maintained by and at the expense of the customer, except as Distributor may agree otherwise in accordance with the provisions of the paragraph next following in this Section II. The facilities necessary to provide service to such systems and installations shall be provided by and at the expense of Distributor's electric system, and the annual investment charge provided for first above in this Section II shall apply to the installed cost of such facilities.

When so authorized by policy duly adopted by Distributor's governing board, traffic signal systems and athletic field lighting installations may be provided, owned, and maintained by Distributor's electric system for the customer's benefit. In such cases Distributor may require reimbursement from the customer for a portion of the initial installed cost of any such system or installation and shall require payment by the customer of an investment charge sufficient to cover all of Distributor's costs (except reimbursed costs), including appropriate overheads, of providing, owning, and maintaining such system or installation; provided that, for athletic field lighting installations, such investment charge shall in no case be less than 12 percent per year of such costs. Said investment charge shall be in addition to the annual investment charge on the facilities necessary to provide service to such system or installation as provided for in the preceding paragraph. Replacement of lamps and related glassware for traffic signal systems and athletic field lighting installations provided under this paragraph shall be paid for under the provisions of paragraph A in Section III.

III. Replacement of Lamps and Related Glassware - Street and park lighting.

Customer shall be billed and shall pay for replacements as provided in paragraph A below, which shall be applied to all service for street and park lighting.

A. Distributor shall bill the customer monthly for such replacements during each month at Distributor's cost of materials, including appropriate storeroom expense.

B. Distributor shall bill the customer monthly for one-twelfth of the amount by which Distributor's cost of materials, including appropriate storeroom expense, exceeds the product of 3 mills multiplied by the number of kilowatthours used for street and park lighting during the fiscal year immediately preceding the fiscal year in which such month occurs.

## Metering

For any billing month or part of such month in which the energy is not metered or for which a meter reading is found to be in error or a meter is found to have failed, the energy for billing purposes for that billing month or part of such month shall be computed from the rated capacity of the lamps (including ballast) plus 5 percent of such capacity to reflect secondary circuit losses, multiplied by the number of hours of use.

## Use-Period For Athletic Field Lighting

Service to athletic field lighting installations under this rate schedule shall not commence earlier than 7 p.m., except that the customer may be permitted to use up to 10 percent (not to exceed 10 kilowatts) of the total installed lighting capacity prior to commencement of such period. In the event the customer fails to restrict service in accordance with these requirements, it shall be billed under the General Power Rate.

## Revenue and Cost Review

Distributor's costs of providing service under Part A of this rate schedule are subject to review at any time and from time to time to determine if Distributor's revenues from the charges being applied are sufficient to cover said costs. If any such review discloses that revenues are either less or more than sufficient to cover said costs, Distributor shall revise the above investment charges so that revenues will be sufficient to cover said costs. Any such revision of the annual investment charge provided for first above in Section II of Part A of this rate schedule shall be by agreement between Distributor and TVA.

## PART B—CHARGES FOR OUTDOOR LIGHTING FOR INDIVIDUAL CUSTOMERS

Charge Per Fixture

| Type of Fixture | Lamp Size (Watts) | Base Monthly Charge |
|---|---|---|
| Mercury Vapor or Incandescent* | 175 | $ 3.00 |
| | 250 | 3.50 |
| | 400 | 4.75 |
| | 700 | 7.75 |
| | 1,000 | 10.00 |
| High Pressure Sodium | 100 | 3.50 |
| | 150 | 3.75 |
| | 250 | 5.00 |
| | 400 | 6.50 |
| | 1,000 | 14.00 |

*Incandescent fixtures not offered for new service.

The above charges in this Part B are limited to service from a photoelectrically controlled standard street lighting fixture installed on a pole already in place. If the customer wishes to have the fixture installed at a location other than on a pole already in place, Distributor may apply a monthly charge not to exceed $2.00 per pole for additional poles required to serve the fixture from Distributor's nearest available source. Distributor may uniformly adjust the above base monthly charges up or down by an amount not to exceed $1.00.

When so authorized by policy duly adopted by Distributor's governing board, special outdoor lighting installations may be provided, owned, and maintained by Distributor's electric system. In such cases Distributor may require reimbursement from the customer for a portion of the initial installed cost of any such installation and shall require payment by the customer of monthly charges sufficient to cover all of Distributor's costs (except reimbursed costs), including appropriate overheads, of providing, owning, and maintaining such installations.

## Lamp Replacements

Replacements of lamps and related glassware will be made in accordance with replacement policies of Distributor without additional charge to the customer.

## Payment

Bills under this rate schedule will be rendered monthly. Any amount of bill unpaid after due date specified on bill may be subject to additional charges under Distributor's standard policy.

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Service is subject to Rules and Regulations of Distributor.

## GENERAL POWER RATE—SCHEDULE GS-10
(October 1976)

### Availability

This rate shall apply to the firm power requirements for electric service to commercial, industrial, and governmental customers; institutional customers including, without limitation, churches, clubs, fraternities, orphanages, nursing homes, rooming or boarding houses, and like customers; and other customers except those to whom service is available under other resale rate schedules.

### Character of Service

Alternating current, single or three-phase, 60 hertz. Under A below power shall be delivered at a voltage available in the vicinity or agreed to by Distributor. Under B below power shall be delivered at a transmission voltage of 161 kV or, if such transmission voltage is not available, at the highest voltage available in the vicinity, unless at the customer's request a lower standard voltage is agreed upon.

### Base Charges

A. If the customer's demand for the month and its contract demand, if any, are each 5,000 kilowatts or less:

Customer Charge: $3.10 per delivery point per month

Demand Charge:

First 50 kilowatts of demand per month, no demand charge
Next 50 kilowatts of demand per month, at $1.90 per kilowatt
Excess over 100 kilowatts of demand per month, at $2.20 per kilowatt

Energy Charge:

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| First 500 | kilowatthours | per | month | at | 2.523 | cents per | kWh* |
| Next 14,500 | " | " | " | " | 2.103 | " " | kWh* |
| Next 25,000 | " | " | " | " | 1.237 | " " | kWh* |
| Next 60,000 | " | " | " | " | 1.147 | " " | kWh* |
| Next 400,000 | " | " | " | " | 1.047 | " " | kWh* |
| Additional | " | " | " | " | 1.007 | " " | kWh* |

*as increased or decreased in accordance with Appendix I to the Schedule of Rates and Charges

B. If either the customer's demand for the month or its contract demand is greater than 5,000 kilowatts:

Customer Charge: $1,000 per delivery point per month

Demand Charge: $1.91 per kilowatt of demand per month

Additional charge for any demand in excess of customer's contract demand: $1.91 per kilowatt per month

Energy Charge: 0.993 cent per kilowatthour per month as increased or decreased in accordance with Appendix I to the Schedule of Rates and Charges

### Facilities Rental Charge Applicable Under B Above

There shall be no facilities rental charge under this rate schedule for delivery at bulk transmission voltage levels of 161 kV or higher. For delivery at less than 161 kV, there shall be added to the customer's bill a facilities rental charge. This charge shall be 20 cents per kW per month except for delivery at voltages below 46 kV, in which case the charge shall be 55 cents per kW per month for the first 10,000 kW and 30 cents per kW per month for the excess over 10,000 kW. Such charge shall be applied to the customer's currently effective contract demand and shall be in addition to all other charges under this rate schedule including minimum bill charges.

### Adjustment

The customer's bill for each month shall be increased or decreased in accordance with the current Adjustment Addendum published by TVA.

## Determination of Demand

Distributor shall measure the demands in kilowatts of all customers having loads in excess of 50 kilowatts. The demand for any month shall be the higher of the highest average during any 30-consecutive-minute period of the month of (a) the load measured in kilowatts or (b) 85 percent of the load in kVA plus an additional 10 percent for that part of the load over 5,000 kVA, and such amount shall be used as the billing demand except that, under B above, the billing demand for any month shall in no case be less than the sum of (1) 40 percent of the first 5,000 kilowatts, (2) 70 percent of the next 45,000 kilowatts, and (3) 90 percent of all kilowatts in excess of 50,000 kilowatts of the higher of the currently effective contract demand or the highest billing demand established during the preceding 12 months.

## Minimum Bill

The monthly bill under A above shall [illegible]

## RESIDENTIAL RATE—SCHEDULE RS-10
(October 1976)

### Availability

This rate shall apply only to electric service to a single family dwelling and its appurtenances, where the major use of electricity is for domestic purposes such as lighting, household appliances, and the personal comfort and convenience of those residing therein. Any such dwelling in which space is occasionally used for the conduct of business by a person residing therein may be served under this rate. Where a portion of a dwelling is used regularly for the conduct of business, the electricity consumed in that portion so used shall be separately metered and billed under the General Power Rate; if separate circuits are not provided by the customer, service to the entire premises shall be billed under the General Power Rate.

### Character of Service

Alternating current, single-phase, 60 hertz. Voltage supplied shall be at the discretion of Distributor and shall be determined by the voltage available from distribution lines in the vicinity and/or other conditions. Multi-phase service shall be supplied in accordance with Distributor's standard policy.

### Base Charges

Customer Charge: $2.10 per delivery point per month

Energy Charge:
First 500 kilowatthours per month at 1.847 cents per kilowatthour*
Additional " " " " 1.717 " " kilowatthour*

*as increased or decreased in accordance with Appendix I to the Schedule of Rates and Charges

### Adjustment

The customer's bill for each month shall be increased or decreased in accordance with the current Adjustment Addendum published by TVA.

### Minimum Monthly Bill

The customer charge constitutes the minimum monthly bill for all customers served under this rate schedule except those customers for which a higher minimum monthly bill is required under Distributor's standard policy because of special circumstances affecting Distributor's cost of rendering service.

### Payment

Bills under this rate schedule will be rendered monthly. Any amount of bill unpaid after due date specified on bill may be subject to additional charges under Distributor's standard policy.

### Single-Point Delivery

The charges under this rate schedule are based upon the supply of service through a single delivery and metering point, and at a single voltage. If service is supplied to the same customer through more than one point of delivery or at different voltages, the supply of service at each delivery and metering point and at each different voltage shall be separately metered and billed under this rate schedule.

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Service is subject to Rules and Regulations of Distributor.

TENNESSEE VALLEY AUTHORITY
SCHEDULE OF RATES AND CHARGES

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WHOLESALE POWER RATE--SCHEDULE WS
(October 1976)

## Availability

Firm power available under long-term contracts with, and for distribution and resale by, States, counties, municipalities, and cooperative organizations of citizens or farmers, all referred to herein as "Distributor."

## Base Charges

| | |
|---|---|
| Delivery Point Charge: | $1,500 per delivery point per month |
| Demand Charge: | $1.81 per kilowatt of demand per month |
| Energy Charge: | 0.950 cent per kilowatthour per month as increased or decreased in accordance with Appendix I to the Schedule of Rates and Charges |

## Adjustments

1. Distributor's bill for each month shall be increased or decreased in accordance with the current Adjustment Addendum published by TVA.

2. Distributor's bill for each month shall be adjusted by adding to the bill 10 cents per kW and 0.02 cent per kWh for power and energy resold by Distributor in the preceding month to any consumer which has a billing demand of more than 10,000 kW or which uses more than 5 million kWh (herein referred to as a large load), except that such adjustment shall not apply to any portion of a large load up to the following respective amounts: 10,000 kW plus an amount (not to exceed 20,000 kW) equal to that portion of Distributor's demand at the TVA delivery point from which such large load is served by Distributor which is in excess of the sum of the billing demands of all large loads served by Distributor from that delivery point; 5 million kWh plus an amount (not to exceed 15 million kWh) equal to that portion of Distributor's purchases of energy at the TVA delivery point from which such large load is served by Distributor which is in excess of the energy resold to all large loads served by Distributor from that delivery point.

## Determination of Demand

The demand for any month shall be the highest average during any 60-consecutive-minute period of the month of (a) the load measured in kilowatts or (b) 85 percent of the load in kVA plus 10 percent of the excess over 5,000 kVA of the maximum kVA demand for the month for each individual consumer, whichever is the higher.

## Facilities Rental

There shall be no facilities rental charge under this rate schedule for delivery at bulk transmission voltage levels of 161 kV or higher. For delivery at less than 161 kV, there shall be added to Distributor's bill a facilities rental charge. This charge shall be 20 cents per kW per month, except for delivery at voltages below 46 kV, in which case the charge shall be 55 cents per kW per month for the first 10,000 kW and 30 cents per kW per month for the excess over 10,000 kW. Such charge shall be applied to the highest billing demand established at each delivery point during the latest 12-consecutive-month period and shall be in addition to all other charges under this rate schedule including minimum bill charges.

## Minimum Bill

The monthly bill, exclusive of Adjustment 2, shall not be less than the higher of (1) the base delivery point charge or (2) 70 percent of the highest billing demand established during the previous 36 months multiplied by the base demand charge (adjusted for the portion of the current Adjustment Addendum applicable to the Distributor's billing demand as provided in Adjustment 1 above). At Distributor's request, in lieu of such minimum bill being applied individually in the case of two or more delivery points through each of which less than half of the energy taken by Distributor is resold to lighting and power consumers with demands of 50 kW or more, the minimum bill, exclusive of Adjustment 2, for any month for such delivery points, considered together, shall instead be an amount equal to the sum of the minimum bills which would otherwise have been applicable to such delivery points for such month; provided, however, that a special minimum bill shall be applied for any delivery point through which more than 75 percent of the energy taken by Distributor is resold to lighting and power consumers with demands of 50 kW or more.

## Single-Point Delivery

The charges under this rate schedule are based upon the supply of service through a single delivery and metering point, and at a single voltage. If service is supplied to Distributor through more than one point of delivery or at different voltages, the supply of service at each delivery and metering point and at each different voltage shall be separately metered and billed under this rate schedule.

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# Schedule of Terms

SCHEDULE OF TERMS AND CONDITIONS

1. Financial and Accounting Policy. Municipality agrees to be bound by the following statement of financial and accounting policy:

(a) Except as hereinafter provided, Municipality shall administer, operate, and maintain the electric system as a separate department in all respects, shall establish and maintain a separate fund for the revenues from electric operations, and shall not directly or indirectly mingle electric system funds or accounts, or otherwise consolidate or combine the financing of the electric system, with those of any other of its operations. The restrictions of this subsection include, but are not limited to, prohibitions against furnishing, advancing, lending, pledging, or otherwise diverting electric system funds, revenues, credit or property to other operations of Municipality, the purchase or payment of, or providing security for, indebtedness or other obligations applicable to such other operations, and payment of greater than standardized or market prices for property or services from other departments of Municipality. In the interest of efficiency and economy, Municipality may use property and personnel jointly for the electric system and other operations, subject to agreement between Municipality and TVA as to appropriate allocations, based on direction of effort, relative use, or similar standards, of any and all joint investments, salaries and other expenses, funds, or use of property or facilities.

(b) Municipality shall keep the general books of accounts of the electric system according to the Federal Power Commission Uniform System of Accounts. Municipality shall allow the duly authorized agents of TVA to have free access at all reasonable times to all books and records relating to electric system operations. TVA may provide advisory accounting service, in reasonable amount, to help assure the proper setting up and administering of such accounts.

(c) Municipality shall supply TVA not later than August 15 of each year with an annual financial report in such form as may be requested, of electric system transactions for the preceding year ending June 30 and of electric system assets and liabilities as of June 30. Municipality shall furnish promptly to TVA such monthly operating, statistical, and financial statements relating to electric system operations as may reasonably be requested by TVA. In the event of failure to furnish promptly such statements TVA, following written notification to Municipality of intention so to do, may with its own staff perform at Municipality's expense all work necessary to collect such data.

(d) Municipality shall have the electric system financial statements examined annually by independent certified public accountants in accordance with generally accepted auditing standards and shall publish the financial statements, along with the auditor's certificate, in a newspaper of general circulation in the area.

2. Payments in Lieu of Taxes. Municipality may pay or cause to be paid from its electric system revenues for each year beginning July 1 (hereinafter called "fiscal year," the first such fiscal year for purposes hereof being the year beginning July 1, 1969), an amount for payments in lieu of taxes (hereinafter called "tax equivalents") on its electric system and electric operations which, in the judgment of Municipality's governing body after consultation with the supervisory body, shall represent the fair share of the cost of government properly to be borne thereby, subject, however, to the following conditions and limitations:

(a) The total amount so paid as tax equivalents for each fiscal year shall not exceed a maximum equal to the sum of the following:

(1) One and one-half times the weighted average effective tax rates of the respective taxing jurisdictions as of the beginning of each fiscal year, determined as hereinafter provided in this section, multiplied by the net plant values of the electric plant in service and the book values of materials and supplies within the respective taxing jurisdictions in which Municipality's electric system is located as of the beginning of such fiscal year; and

(2) Two and one-half percent of the adjusted net distribution plant value of electric plant in service within the corporate limits of Municipality and of any other city taxing jurisdiction as of the beginning of each fiscal year; and

(3) One and one-half percent of the adjusted net distribution plant value of electric plant in service outside the corporate limits of Municipality and of any other city taxing jurisdictions as of the beginning of each fiscal year.

(b) Notwithstanding the foregoing, until the first fiscal year in which the aforesaid maximum amount for payments in lieu of taxes calculated as provided in subparagraph (a) of this section exceeds the total of (1) and (2) of this subparagraph (b), the maximum total tax equivalent that may be paid for any fiscal year shall not be less than the sum of the following:

(1) The highest total annual amount in lieu of taxes taken or paid from Municipality's electric system funds prior to April 1, 1969, for any one of the three consecutive calendar years ending with calendar year 1968, increased by the same percentage as that by which the net plant value has increased from December 31, 1968, through June 30, 1969; and

(2) The amount by which the result of the calculation of item (1) in subparagraph (a) of this section for such fiscal year exceeds the result of such a calculation for the year ending with June 30, 1969.

Thereafter, such maximum for any fiscal year shall not exceed the aforesaid maximum calculated as provided in subparagraph (a) of this section. All such maximum amounts shall be subject to the conditions and limitations of subparagraphs (c), (d), and (e) of this section.

(c) Such tax equivalent payments shall be made only from current electric system revenues remaining after payment of or making reasonable provision for payment of (i) current operating expenses of the electric system, including without limitation salaries, wages, cost of materials and supplies, cost of power, and insurance; (ii) current payments of interest on electric system indebtedness, and payment of principal thereof, including amortization, reserve and sinking fund payments, when due; and (iii) reasonable reserves for renewals, replacements, and contengencies and for cash working capital.

(d) The total tax equivalent to be paid for each fiscal year shall be in lieu of all State, county, city, and other local taxes or charges on Municipality's electric system and electric operations except as provided in subparagraph (f) of this section. Accordingly, after initial determination of such total tax equivalent to be paid in the absence of any such taxes or charges, such total tax equivalent shall be reduced by the aggregate amount of any taxes or other charges imposed for such fiscal year on Municipality's electric system or electric operations for the benefit of the respective taxing jurisdictions (including Municipality) in which Municipality's electric system is located and in which such electric operations are conducted, whether or not such taxes or other charges were imposed by the respective taxing jurisdictions receiving the benefit thereof. It shall be the responsibility of Municipality to provide for allocation of such total tax equivalent among the taxing jurisdictions in which Municipality's electric system is located in accordance with applicable law or contracts, but any amount so allocated to any such taxing jurisdiction shall be reduced by the aggregate amount of any such tax or other charges imposed for that fiscal year for the benefit of that taxing jurisdiction. Only the respective amounts remaining after the aforesaid allocated amounts have been so reduced shall be actually paid to Municipality and to such other taxing jurisdictions.

(e) The amounts to be paid for each fiscal year to Municipality and to each other taxing jurisdiction, determined in accordance with and subject to the provisions of this section 2, shall be set forth in a resolution adopted by Municipality's governing body after consultation with the supervisory body, and Municipality's electric system shall pay such amounts to Municipality and the other taxing jurisdictions as provided in said resolution. Such determination shall be made as early in such fiscal year as possible and shall become final at the end of such year; provided, however, that any reductions in such amounts required by subsection (d) above, to the extent not made during such year, shall be made in the succeeding years until the full adjustments are completed.

(f) Notwithstanding anything in the foregoing which might be construed to the contrary, properly authorized retail sales or use taxes on electric power or energy at the same rates applicable generally to sales or use of personal property or services, including natural or artificial gas, coal, and fuel oil as well as electric power or energy, imposed upon the vendees or users thereof by the State, a county, or a city (including Municipality) on a statewide, countywide, or citywide basis, respectively, shall not be considered a tax or charge on Municipality's electric system or its electric operations or properties for purposes of this section 2.

For purposes of this section 2, the following terms shall have the following meanings:

(a) "Electric system" shall mean all tangible and intangible property and resources of every kind and description used or held for use in the purchase, transmission, distribution, and sale, but not the generation, of electric energy.

(b) "Electric operations" shall mean all activities associated with the establishment, development, and administration of an electric system and the business of supplying electricity and associated services to the public, including without limitation the generation, purchase, and sale of electric energy and the purchase, use, and consumption thereof by ultimate consumers.

(c) "Supervisory body" shall mean any board or other agency of Municipality established to supervise the management and operation of its electric system and electric operations, or, in the absence thereof, the governing body of Municipality.

(d) The term "weighted average effective tax rate" of any taxing jurisdiction shall mean the actual ad valorem real property tax rate in effect multiplied by the weighted average ratio of the assessed value to market value of all classes or real property within such taxing jurisdiction. Said weighted average ratio of assessed to market value for any taxing jurisdiction shall be determined by dividing (1) the total actual assessed valuation of all classes of taxable real property within such jurisdiction, by (2) the total market value of the same classes of taxable real property within the jurisdiction included in (1), calculated from the assessment ratios determined and published by any authorized agency of the State of Tennessee or, in the absence thereof, by the Tennessee Taxpayers Association, or, if such information is unavailable from either of these sources, from the best information available. For purposes of this section 2, the weighted average effective tax rate in effect at the beginning of any fiscal year for any taxing jurisdiction shall be deemed to be the weighted average effective tax rate of such taxing jurisdiction determined as provided in this paragraph for the tax year (calendar year) immediately preceding such fiscal year using the actual property tax rate and assessment ratios of such taxing jurisdiction in effect for such tax year.

(e) "Net plant value" shall mean the depreciated original cost of electric plant in service used and held for use in the transmission and distribution, but not the generation, of electricity as shown on the books of the electric system from time to time.

(f) "Adjusted net distribution plant value" shall mean net plant value less the depreciated original cost of (1) underground plant in service and (2) electric lines and equipment in service designed for operation at voltages in excess of 26,000 volts.

(g) "Electric plant in service" or "plant in service" shall have the meanings defined or ascribed to them in the Federal Power Commission's Uniform System of Accounts.

3. Municipality's Lines and Equipment. All lines and substations from the point or points of delivery (as defined in section 3 of the contract of which these Terms and Conditions are a part), and all electrical equipment, except metering equipment of TVA, located on Municipality's side of such point or points of delivery shall be furnished and maintained by Municipality. Municipality's electrical facilities shall conform to accepted modern standards. Failure to inspect for or to object to defects in such facilities shall not render TVA liable or responsible for any loss or damage resulting therefrom or from violation of the contract of which these Terms and Conditions are a part, or from accidents which may occur upon Municipality's premises.

4. Responsibility for Property of the Other Party. All equipment furnished by each party shall be and remain its property. Each party shall exercise proper care to protect any property of the other on its premises, and shall bear the cost of any necessary repairs or replacements arising from its neglect to exercise such proper care. The authorized employees of each party shall have access at all reasonable times to any of its facilities on the other's premises, for such purposes as reading its meters, and testing, repairing, or replacing its equipment.

5. Measurement of Demand, Energy, and Power Factor. TVA will, at its own expense, install and maintain or cause to be installed and maintained the necessary metering equipment for measuring the maximum demand and the amount of energy furnished Municipality at each point of delivery. If, for economy or convenience, such equipment is located elsewhere than at the point of delivery, the readings shall be adjusted to reflect the quantities delivered at the point of delivery and such adjusted amounts shall be deemed to be the measured amounts for purposes of billing under Wholesale Rate Schedule WS. TVA may also, at its option, provide equipment to determine power factor. Municipality shall permit the use of its housing facilities, ducts and supports for TVA's metering equipment.

Municipality shall have the right at its own expense to install, equip, and maintain check meters in a mutually satisfactory location.

TVA will make periodical tests and inspections of its metering equipment in order to maintain a high standard of accuracy, and will make additional tests or inspections of its metering equipment at the request of Municipality. Municipality shall have the right to have representatives present at tests and meter readings. If any test shows that the metering equipment is accurate within two percent no adjustment of past readings will be made and, if the test was requested by Municipality, the testing charge will be paid by Municipality; all other tests shall be at TVA's expense. In case any test shows the meter reading to be in error more than two percent, a corresponding adjustment shall be made in Municipality's bills for any agreed period of error; in the absence of such agreement, the adjustment shall be limited to the current billing period. Should the metering equipment fail, the deliveries will be estimated by TVA from the best information available.

6. Billing. Payment for power and energy used in any monthly period shall become due fifteen days after TVA's meter reading date or seven days after the date of bill from TVA, whichever is later. To any amount remaining unpaid fifteen days after the due date, there shall be added a charge of one percent and an additional one percent shall be added for each succeeding thirty-day period until the amount is paid in full. Upon failure of Municipality to pay for the power and energy used in any monthly period within sixty days after due date, TVA shall have the right, upon reasonable notice, to discontinue the supply of power and energy and refuse to resume delivery so long as any part thereof remains unpaid. Discontinuance of supply under this section will not relieve Municipality of its liability for the agreed minimum monthly payment during the time the supply of energy is so discontinued. All payments shall be made to TVA at its offices at Chattanooga, Tennessee, or at such other place as TVA may from time to time designate. For purposes of billing, the term "month" in Wholesale Power Rate--Schedule WS and the term "monthly period" in this section are defined as the period from the meter reading time in one month to the meter reading time in the next month; provided, however, that with respect to the determination of demand said period shall begin and end at midnight prior to said meter reading times. Subject to such changes in TVA's meter reading scheduling as it deems necessary, meters shall be read on the same day of each month.

7. Adjustment and Change of Wholesale Rate and Resale Rates. The wholesale rate and resale rates provided in sections 4 and 5 of the contract shall

be subject to adjustment and change from time to time in accordance with this section in order to assure TVA's ability to continue to supply the power requirements of Municipality and TVA's other customers on a financially sound basis with due regard for the primary objectives of the TVA Act, including the objective that power shall be sold at rates as low as feasible, and to assure Municipality's ability to continue to operate on a financially sound basis.

Wholesale power rates and charges shall be sufficient to produce revenue from TVA's wholesale power customers which, together with revenue from its other power customers, will assure TVA's ability each fiscal year to:

(a) meet the requirements of the TVA Act including particularly section 15d(f) thereof which provides in part that:

> The Corporation shall charge rates for power which will produce gross revenues sufficient to provide funds for operation, maintenance, and administration of its power system; payments to States and counties in lieu of taxes; debt service on outstanding bonds, including provision and maintenance of reserve funds and other funds established in connection therewith; payments to the Treasury as a return on the appropriation investment pursuant to subsection (e) hereof; payment to the Treasury of the repayment sums specified in subsection (e) hereof; and such additional margin as the Board may consider desirable for investment in power system assets, retirement of outstanding bonds in advance of maturity, additional reduction of appropriation investment, and other purposes connected with the Corporation's power business, having due regard for the primary objectives of the Act, including the objective that power shall be sold at rates as low as are feasible.

and (b) meet all tests and comply with the provisions of TVA's bond resolutions as from time to time adopted and amended in such a manner as to assure its ability to continue to finance and operate its power program at the lowest feasible cost.

Adjustment. TVA will review with Municipality or its representative, at least 30 days prior to the first day of each of the months of October, January, April, and July pertinent data concerning the current and anticipated conditions and costs affecting TVA's operations and the adequacy of its revenues from both wholesale and other power customers to meet the requirements of the TVA Act and the tests and provisions of its bond resolutions as provided in the second paragraph of this section. At least fifteen days prior to the first day of each of the aforesaid months, TVA will determine what adjustments, if any, are required in the demand and energy charges provided for in the then effective Schedule of Rates and Charges to assure (a) revenues to TVA adequate to meet the requirements of the TVA Act and the tests and provisions of its bond resolutions as provided in the second paragraph of this section and (b) revenues to Municipality adequate to compensate for changes, if any, in the cost of power to Municipality resulting from adjustments to Wholesale Power Rate--Schedule WS made under the provisions of this section. Such adjustments as TVA determines are required shall be incorporated by TVA in Adjustment Addendums to Wholesale Power Rate--Schedule WS and to the resale schedules of the Schedule of

Rates and Charges, which Adjustment Addendums shall be promptly published by TVA by mailing the same to Municipality by registered mail and shall be applicable to bills rendered from meter readings taken for TVA and Municipality billing cycles scheduled to begin on or after the effective date of said Adjustment Addendum; provided that any adjustment determined by TVA to be necessary as hereinbefore provided shall not be conditioned upon or be postponed pending the review provided for in the first sentence of this paragraph or the completion of such review. Municipality shall pay for power and energy in accordance with Wholesale Power Rate--Schedule WS of the Schedule of Rates and Charges as so adjusted from time to time by any such Adjustment Addendums published by TVA as above provided, and shall adjust the charges in the resale schedules of the Schedule of Rates and Charges applicable to its customers in accordance with such Adjustment Addendums and the provisions of such resale schedules.

Change. Whenever any adjustment or adjustments made under the preceding paragraph, or the costs of TVA's service to Municipality and TVA's other customers, or the costs of Municipality's service to customers, or any other factors are believed by either party to warrant general or major changes in the Schedule of Rates and Charges, either party or its representative may request that the parties or their representatives meet and endeavor to reach agreement upon such changes. If within 180 days after any request for such changes the representatives of the parties for any reason have not agreed upon such changes, TVA may thereafter, upon not less than 30 days' notice by registered mail in which the basis for each change is set forth, place into effect such changes in the Schedule of Rates and Charges as it determines will enable TVA to carry out the objectives of the TVA Act and meet the requirements and tests and comply with the provisions of its bond resolutions as outlined in the second paragraph of this section and enable Municipality to continue on a financially sound basis as provided in section 5(c) of the contract and Municipality shall thereafter pay and charge for power and energy in accordance with the Schedule of Rates and Charges as so changed; provided, however, that unless the parties agree otherwise, any adjustment determined by TVA to be required under the provisions of the preceding paragraph of this section shall become effective without reference to, and shall not be delayed or postponed pending completion of, any actions under this paragraph.

8. Compensation for Additional Tax or in Lieu of Tax Payments. It is recognized that among the costs which the rates specified in Wholesale Power Rate--Schedule WS were designed to cover are annual payments in lieu of taxes by TVA in an aggregate sum equivalent to 5 percent of its gross proceeds from sales of power exclusive of sales to agencies of the Government of the United States. If at any time TVA is compelled by law to pay during any fiscal year ending June 30 taxes and payments in lieu of taxes in an aggregate amount which shall exceed 5 percent of such proceeds, TVA may, if it so elects, increase the billing amounts during the succeeding fiscal year by the number of percentage points (to the nearest 0.1 point) by which said aggregate amount exceeded 5 percent of said proceeds.

9. Interference with Availability or Use of Power. Neither TVA nor Municipality shall be liable for damages or breach of contract when and to the extent that the availability or use of power, respectively, is interrupted, curtailed or interfered with or the performance of any other obligation hereunder is prevented by circumstances reasonably beyond the control of the party affected,

15. <u>Conflict.</u> In case of conflict between any express provision of the body of this contract or any provision of the Schedule of Rates and Charges and these Terms and Conditions, the former shall govern.

16. <u>Section Headings.</u> The section headings in this contract are only for convenience of reference and are not a part of the contract between the parties.

# Schedule of Rules and Regulations

## SCHEDULE OF RULES AND REGULATIONS

1. Application for Service. Each prospective Customer desiring electric service may be required to sign Distributor's standard form of application for service or contract before service is supplied by the Distributor.

2. Deposit. A deposit or suitable guarantee approximately equal to twice the average monthly bill may be required of any Customer before electric service is supplied. Distributor may at its option return deposit to Customer after one year. Upon termination of service, deposit may be applied by Distributor against unpaid bills of Customer, and if any balance remains after such application is made, said balance shall be refunded to Customer.

3. Point of Delivery. The point of delivery is the point, as designated by Distributor, on Customer's premises where current is to be delivered to building or premises. All wiring and equipment beyond this point of delivery shall be provided and maintained by Customer at no expense to Distributor.

4. Customer's Wiring--Standards. All wiring of Customer must conform to Distributor's requirements and accepted modern standards, as exemplified by the requirements of the National Electrical Safety Code and the National Electrical Code.

5. Inspections. Distributor shall have the right, but shall not be obligated, to inspect any installation before electricity is introduced or at any later time, and reserves the right to reject any wiring or appliances not in accordance with Distributor's standards; but such inspection or failure to inspect or reject shall not render Distributor liable or responsible for any loss or damage resulting from defects in the installation, wiring, or appliances, or from violation of Distributor's rules, or from accidents which may occur upon Customer's premises.

6. Underground Service Lines. Customers desiring underground service lines from Distributor's overhead system must bear the excess cost incident thereto. Specifications and terms for such construction will be furnished by Distributor on request

7. Customer's Responsibility for Distributor's Property. All meters, service connections, and other equipment furnished by Distributor shall be, and remain, the property of Distributor. Customer shall provide a space for and exercise proper care to protect the property of Distributor on its premises, and, in the event of loss or damage to Distributor's property arising from neglect of Customer to care for same, the cost of the necessary repairs or replacements shall be paid by Customer.

8. Right of Access. Distributor's identified employees shall have access to Customer's premises at all reasonable times for the purpose of

reading meters, testing, repairing, removing, or exchanging any or all equipment belonging to Distributor.

9. Billing. Bills will be rendered monthly and shall be paid at the office of Distributor or at other locations designated by Distributor. Failure to receive bill will not release Customer from payment obligation. Should bills not be paid as above, Distributor may at any time thereafter, upon five (5) days' written notice to Customer, discontinue service. Bills paid after due date specified on bill may be subject to additional charges. Should the due date of bill fall on a Sunday or holiday, the business day next following the due date will be held as a day of grace for delivery of payment. Remittances received by mail after the due date will not be subject to such additional charges if the incoming envelope bears United States Postal Service date stamp of the due date or any date prior thereto.

10. Discontinuance of Service by Distributor. Distributor may refuse to connect or may discontinue service for the violation of any of its Rules and Regulations, or for violation of any of the provisions of the Schedule of Rates and Charges, or of the application of Customer or contract with Customer. Distributor may discontinue service to Customer for the theft of current or the appearance of current theft devices on the premises of Customer. The discontinuance of service by Distributor for any causes as stated in this rule does not release Customer from his obligation to Distributor for the payment of minimum bills as specified in application of Customer or contract with Customer.

11. Connection, Reconnection, and Disconnection Charges. Distributor may establish and collect standard charges to cover the reasonable average cost, including administration, of connecting or reconnecting service, or disconnecting service as provided above. Higher charges may be established and collected when connections and reconnections are performed after normal office hours, or when special circumstances warrant.

12. Termination of Contract by Customer. Customers who have fulfilled their contract terms and wish to discontinue service must give at least three (3) days' written notice to that effect, unless contract specifies otherwise. Notice to discontinue service prior to expiration of contract term will not relieve Customer from any minimum or guaranteed payment under any contract or rate.

13. Service Charges for Temporary Service. Customers requiring electric service on a temporary basis may be required by Distributor to pay all costs for connection and disconnection incidental to the supplying and removing of service. This rule applies to circuses, carnivals, fairs, temporary construction, and the like.

14. Interruption of Service. Distributor will use reasonable diligence in supplying current, but shall not be liable for breach of contract in the event of, or for loss, injury, or damage to persons or property resulting from, interruptions in service, excessive or inadequate voltage, single-phasing, or otherwise unsatisfactory service, whether or not caused by negligence.

15. Shortage of Electricity. In the event of an emergency or other condition causing a shortage in the amount of electricity for Distributor to meet the demand on its system, Distributor may, by an allocation method deemed equitable by Distributor, fix the amount of electricity to be made available for use by Customer and/or may otherwise restrict the time during which Customer may make use of electricity and the uses which Customer may make of electricity. If such actions become necessary, Customer may request a variance because of unusual circumstances including matters adversely affecting the public health, safety and welfare. If Customer fails to comply with such allocation or restriction, Distributor may take such remedial actions as it deems appropriate under the circumstances including temporarily disconnecting electric service and charging additional amounts because of the excess use of electricity. The provisions of the Section entitled Interruption of Service of this Schedule of Rules and Regulations are applicable to any such allocation or restriction.

16. Voltage Fluctuations Caused by Customer. Electric service must not be used in such a manner as to cause unusual fluctuations or disturbances to Distributor's system. Distributor may require Customer, at his own expense, to install suitable apparatus which will reasonably limit such fluctuations.

17. Additional Load. The service connection, transformers, meters, and equipment supplied by Distributor for each Customer have definite capacity, and no addition to the equipment or load connected thereto will be allowed except by consent of Distributor. Failure to give notice of additions or changes in load, and to obtain Distributor's consent for same, shall render Customer liable for any damage to any of Distributor's lines or equipment caused by the additional or changed installation.

18. Standby and Resale Service. All purchased electric service (other than emergency or standby service) used on the premises of Customer shall be supplied exclusively by Distributor, and Customer shall not, directly or indirectly, sell, sublet, assign, or otherwise dispose of the electric service or any part thereof.

19. Notice of Trouble. Customer shall notify Distributor immediately should the service be unsatisfactory for any reason, or should there be any defects, trouble, or accidents affecting the supply of electricity. Such notices, if verbal, should be confirmed in writing.

20. Non-Standard Service. Customer shall pay the cost of any special installation necessary to meet his peculiar requirements for service at other than standard voltages, or for the supply of closer voltage regulation than required by standard practice.

21. Meter Tests. Distributor will, at its own expense, make periodical tests and inspections of its meters in order to maintain a high standard of accuracy. Distributor will make additional tests or inspections of its meters at the request of Customer. If tests made at Customer's request show that the meter is accurate within two percent (2%), slow or fast, no adjustment will be made in Customer's bill, and Distributor's standard testing

charge will be paid by Customer. In case the test shows meter to be in excess of two percent (2%) fast or slow, an adjustment shall be made in Customer's bill over a period of not over thirty (30) days prior to date of such test, and cost of making test shall be borne by Distributor.

22. Relocation of Outdoor Lighting Facilities. Distributor shall, at the request of Customer, relocate or change existing Distributor-owned equipment. Customer shall reimburse Distributor for such changes at actual cost including appropriate overheads.

23. Billing Adjusted to Standard Periods. The demand charges and the blocks in the energy charges set forth in the rate schedules are based on billing periods of approximately one month. In the cese of the first billing of new accounts (temporary service, cotton gins, and other seasonal customers excepted) and final billings of all accounts (temporary service excepted) where the period covered by the billing involves fractions of a month, the demand charges and the blocks of the energy charge will be adjusted to a basis proportionate with the period of time during which service is extended.

24. Scope. This Schedule of Rules and Regulations is a part of all contracts for receiving electric service from Distributor, and applies to all service received from Distributor, whether the service is based upon contract, agreement, signed application, or otherwise. A copy of this schedule, together with a copy of Distributor's Schedule of Rates and Charges, shall be kept open to inspection at the offices of Distributor.

25. Revisions. These Rules and Regulations may be revised, amended, supplemented, or otherwise changed from time to time, without notice. Such changes, when effective, shall have the same force as the present Rules and Regulations.

26. Conflict. In case of conflict between any provision of any rate schedule and the Schedule of Rules and Regulations, the rate schedule shall apply.

# Assignment Agreement

**ASSIGNMENT AGREEMENT**
**Among**
**CITY OF JACKSON, TENNESSEE,**
**JACKSON ENERGY AUTHORITY,**
**And**
**TENNESSEE VALLEY AUTHORITY**

Date: November 1, 2001

TV-47356A, Supp. No. 68

THIS AGREEMENT, made and entered into by and among CITY OF JACKSON, TENNESSEE (Municipality), a municipal corporation created and existing under and by virtue of the laws of the State of Tennessee; JACKSON ENERGY AUTHORITY (Assignee), a public corporation created and existing under and by virtue of the laws of the State of Tennessee; and TENNESSEE VALLEY AUTHORITY (TVA), a corporation created and existing under and by virtue of the Tennessee Valley Authority Act of 1933, as amended;

**W I T N E S S E T H:**

WHEREAS, TVA and Municipality have heretofore entered into Power Contract TV-47356A, dated August 12, 1977, as amended (1977 Contract), and related agreements under which Municipality purchases its entire requirements for electric power and energy from TVA for resale; and

WHEREAS, Assignee is in the process of acquiring and plans to operate the electric utility system of Municipality as provided for by Chapter 55 of the Tennessee Private Acts of 2001 (2001 Act); and

WHEREAS, Municipality has requested TVA's consent to the assignment of the 1977 Contract and related agreements from Municipality to Assignee; and

WHEREAS, TVA is willing to consent to this assignment subject to the terms and conditions set forth below;

NOW, THEREFORE, for and in consideration of the premises and of the mutual agreements set forth below, and subject to the provisions of the Tennessee Valley Authority Act of 1933, as amended, the parties agree as follows:

1. Effective as of the date first above written (Effective Date), Municipality hereby assigns to Assignee the 1977 Contract, including all rights and obligations included therein, and TVA hereby consents to such assignment in accordance with the provisions of section 12 of the 1977 Contract.

2. Municipality hereby also assigns to Assignee (and TVA consents to such assignment) the following agreements, including all rights and obligations included therein:

(a) Industrial Development Contract TV-58454A, dated December 21, 1981.

(b) Letter Agreement TV-71888A, dated July 14, 1987.

(c) Letter Agreement TV- 74673A, dated February 4, 1988.

(d) Letter Agreement TV-75737A, dated August 10, 1988.

(e) Mobile Spare Transformer Program Agreement TV-80220U, dated November 27, 1989.

(f) Power Supply Contract TV-85861U, dated March 1, 1992.

(g) Power Supply Contract TV-98618U, dated May 1, 1995.

(h) Comprehensive Services Program Agreement TV-99211U, dated July 1, 1995.

(i) Purchase Agreement TV-98678U, dated January 1, 1996.

(j) Energy Right Residential Program Agreement 98PCG-227153, dated October 1, 1997.

(k) Direct Load Control Agreement 98PCG-231567, dated October 1, 1997.

(l) Power Supply Contract 01PCG-267209, dated September 1, 2000.

(m) Power Supply Contract 00PCG-266825, dated September 25, 2000.

(n) Power Supply Contract 00PCG-264479, dated April 1, 2000.

(o) Power Supply Contract 01PCG-268921, dated November 1, 2000.

3. Assignee, by virtue of said assignment, becomes bound for the full performance of the 1977 Contract.

4. In the event that Assignee shall cease to exist as addressed by section 25 of the 2001 Act or otherwise, all rights and obligations of Assignee under the 1977 Contract shall become the rights and obligations of Municipality without further action by TVA, Municipality, or Assignee.

5. The 1977 Contract is amended in all respects necessary to make all references to Municipality refer to Assignee except for the references with respect to payments in lieu of taxes in the third sentence of section 1, section 6(a)(4), and section 2 of the Schedule of Terms and Conditions, which shall continue to refer to the City of Jackson.

IN WITNESS WHEREOF, the parties to this agreement have caused it to be executed by their duly authorized representatives, as of the day and year first above written.

**CITY OF JACKSON, TENNESSEE**

By Charles H. Farmer
Title:

**JACKSON ENERGY AUTHORITY**

By John W. Williams
Title: President

**TENNESSEE VALLEY AUTHORITY**

By Mark O. Medford
Executive Vice President
Customer Service and Marketing

# EXHIBIT 6

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# Integrated Resource Plan – Draft Results

PSAT Meeting | May 29, 2020

## Agenda

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- Overview / Meeting Objectives – J.T. Young — 10:00 am
- Agenda and Executive Summary - Siemens — 10:10 am
- MISO Overview and Membership Assessment - MISO — 10:40 am
- Questions of PSAT to MISO — 11:30 am
- Break — 11:40 am
- IRP Overview - Siemens — 11:50 am
  - Introduction
  - Strategies / Scenarios / Portfolio Analyzed
  - Metrics
  - Load Forecast / Fuel Forecast / Technology Assessment
  - Transmission / Resource Adequacy Issues
  - Other Costs for Direct Comparison
  - Portfolio Analyses (deterministic, stochastic and Waterfall)
  - Summary of Conclusions and Recommendations
  - Next Steps
- Break — 1:20 pm
- Questions and Comments from PSAT — 1:30 pm

# Introduction

## IRP Process Recap

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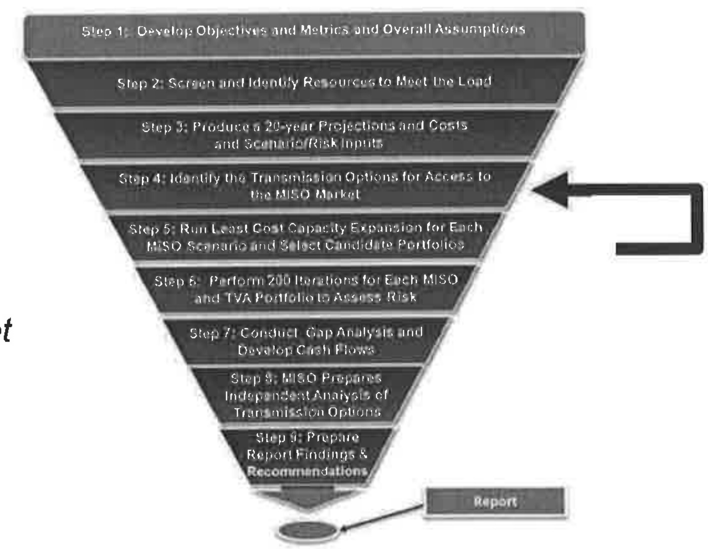
- The IRP process is designed to evaluate options for MLGW to supply of its current and forecasted load while meeting key objectives including:

  - *Affordability / Least Cost / Rate Impact*
  - *Reliability / Resource Adequacy*
  - *Sustainability / CO2 / Water Use / RPS*
  - *Stability / Price Risk Mitigation / Reliance on Market*
  - *Economic Impact / Local Capital Investment*

- Today we will present the results of the final set of Portfolios and our findings and recommendations.



# Integrated Resource Planning… a Recap

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## Why do an IRP?

The Integrated Resource Plan is:

- Independent and unbiased
- Comprehensive regarding strategies and options
- Addresses the risk associated with market, regulatory and technology uncertainty
- Compares the TVA Full Requirements Contract to alternatives on an equivalent basis (generation, plus transmission, PILOT, Gap analysis, MISO charges, TVA Benefits, becoming LBA)
- Determines No Regret Strategies

## What is an IRP?

The purpose of an IRP is to provide a plan for energy resource (primarily generation, transmission and demand side programs) development to meet future load and compare the status quo (TVA FRC) to MISO market and self generation options):

This is not a traditional IRP which focuses primarily on generation. Exiting TVA requires a combination of generation and transmission investments to replace TVA supply.

Least cost plans are developed for a given transmission infrastructure – hence alignment between Siemens and MISO's assumptions regarding transmission are critical inputs to the analysis.

# Integrated Resource Planning… a Recap

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## What we will do today

- Siemens will present analyses and results that MLGW can use to determine the best path forward for Memphis
- Siemens will present its findings regarding the tradeoffs among cost, risk, reliability, sustainability, resilience, and economic development
- Siemens will
  - review previous materials,
  - fill in gaps in information that not covered in previous presentations (PILOT, benefits, gap analyses, TVA cost),
  - present the results of the Risk Analysis,
  - Present the balanced Scorecard,
  - Explain No Regret Positions for each Strategy,
  - Describe the Waterfall showing the components of Savings among Strategies
  - Recommend next steps (RFP to confirm savings)

## What we will not do today

- Siemens will not make a final recommendation regarding whether MLGW should exit the TVA agreement – that is an MLGW decision
- Siemens has no view regarding which of the metrics is the most important to MLGW
- Siemens believes that MLGW should conduct an RFP to verify savings before making a final decision regarding both TVA and the best Portfolio options. However its timing is an MLGW decision.

# Summary of Findings

# 11 Resource Portfolios under Self-Supply plus MISO (Strategy 3) and All MISO (Strategy 4) were Evaluated

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| Portfolio ID | Final Portfolio | Total Thermal 2039 | Local Renew 2039 | Battery 2039 | Total Local Nameplate 2039 | MISO Renew 2039 | MISO Cap 2039 | 950 MW CC | 450 MW CC | 237 MW CT |
|---|---|---|---|---|---|---|---|---|---|---|
| S3S1_P | Portfolio 1 | 1137 | 1000 | 0 | 2137 | 2200 | 1761 | 0 | 2 | 1 |
| S3S1_F | Portfolio 2 | 1587 | 1000 | 0 | 2587 | 1550 | 1487 | 0 | 3 | 1 |
| S3S2_BB | Portfolio 3 | 1824 | 1000 | 0 | 2824 | 1350 | 1308 | 0 | 3 | 2 |
| [illegible]_BB | Portfolio 4 | 1350 | 1000 | 0 | 2350 | 1550 | 1697 | 0 | 3 | 0 |
| S3S5 | Portfolio 5 | 1398 | 1000 | 100 | 2498 | 3450 | 1183 | 0 | 1 | 4 |
| S3S7_BB | Portfolio 6 | 1137 | 1000 | 0 | 2137 | 2200 | 1761 | 0 | 2 | 1 |
| S3S1_2CT | Portfolio 7 | 1374 | 1000 | 0 | 2374 | 2200 | 1550 | 0 | 2 | 2 |
| S3S7_2CT | Portfolio 8 | 1374 | 1000 | 0 | 2374 | 2200 | 1550 | 0 | 2 | 2 |
| S3S5_YD | Portfolio 9 | 1398 | 1000 | 100 | 2498 | 3450 | 1186 | 0 | 1 | 4 |
| S3S10 | Portfolio 10 | 950 | 1000 | 0 | 1950 | 2250 | 1901 | 1 | 0 | 0 |
| S4S1 | Portfolio All MISO | 950 | 0 | 0 | 0 | 3200 | 1909 | 1 | 0 | 0 |

- Portfolio 1, 2 and 7: derived from the Reference case.
- Portfolio 3: derived from High Load / Base Gas case.
- Portfolio 4: derived from Low Load / Base Gas case.
- Portfolio 5 and 9: derived from High Transmission case, with battery storage (9 moved CTs to 2025).
- Portfolio 6 and 8: derived from Low Load / High Gas case (different numbers of CTs and timing).
- Portfolio All MISO: derived without local supply options.
- Portfolio 10: Shifted the CCGT and 1000 MW MISO renewables to local.

## Summary of Findings

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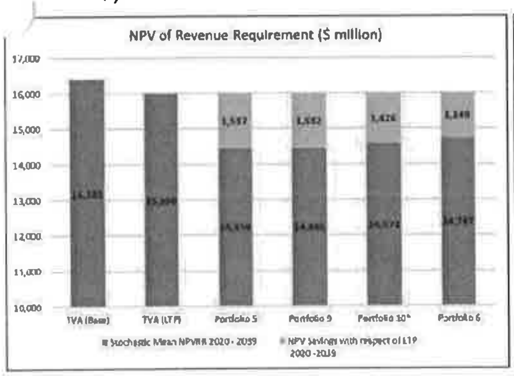
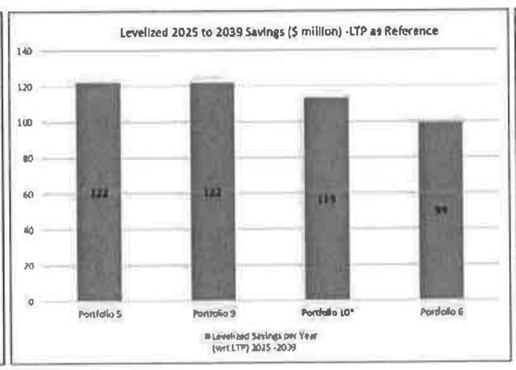
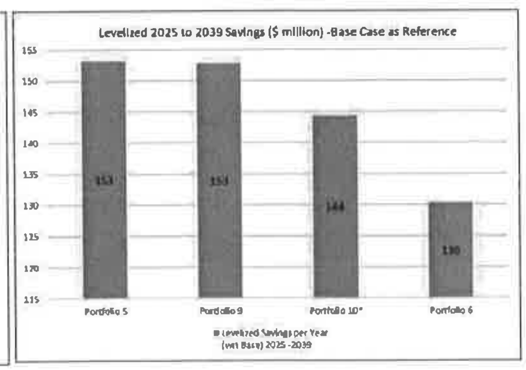
- Future supply Portfolios 5 and 9 were identified that could provide savings of over $1.9 billion in 2018 dollars for the 2020 to 2039 period with respect of the TVA's Existing Contract and $1.5 billion (shown lower left) with respect of the Long Term Partnership contract. The sum of the $1.9 billion savings becomes about $3 billion in nominal dollars (including inflation).
- These two portfolios could achieve in annual savings of about $150 million per year (2025-2039) with TVA's Existing Contract (lower middle) and about $120 million per year (2025-2039) with TVA's LTP (in 2018$). In nominal dollars the $150 million averages about $200 million/year (assuming 2% inflation).



## Summary of Findings

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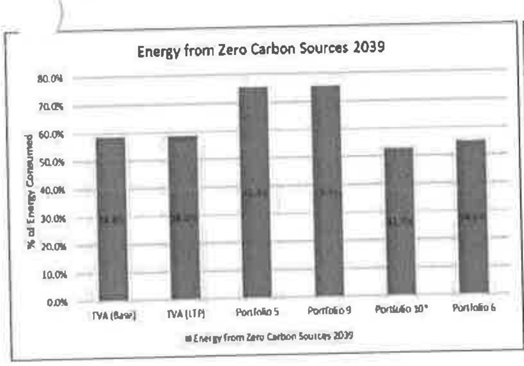
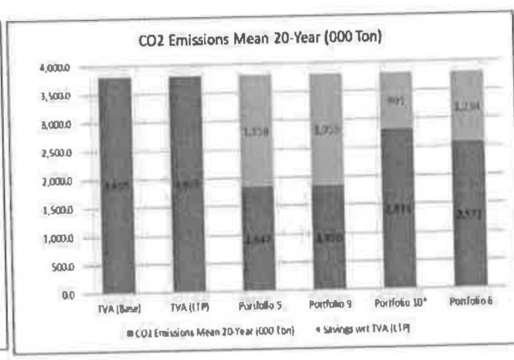
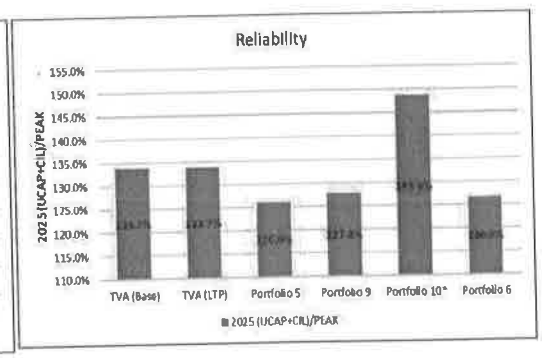
- All of the best performing Self Supply plus MISO Portfolios have high levels of generation from zero carbon sources reaching levels from 52% to 75% when fully developed.
- $CO_2$ emissions are reduced by almost 50% of TVA levels with Portfolios 5 and 9.
- There will be an increase of local water consumption for generation of about 27% relative to TVA
- All Portfolios meet or surpass NERC reliability requirements, but Portfolio 5 has potential risk of load shed during double 500 kV line outages. This was addressed in Portfolio 9.



# MISO Overview and Membership Assessment

# Memphis Light, Gas and Water (MLGW) Power Supply Advisory Team Meeting

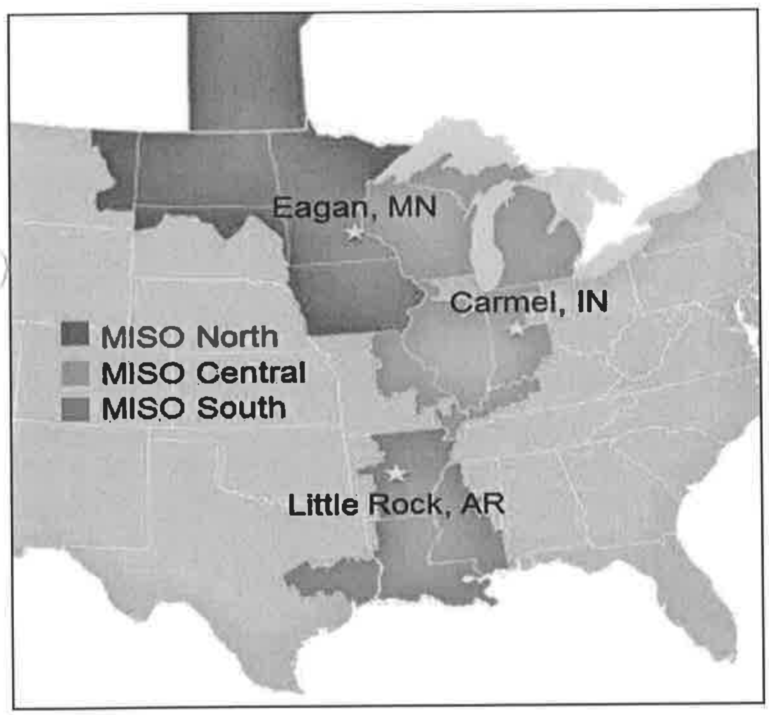
May 29, 2020

MISO

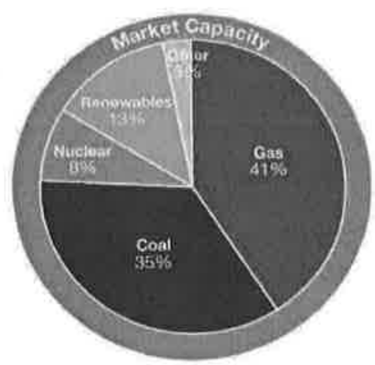
# Part I: MISO Overview

# MISO drives value creation through efficient and reliable markets, operations, planning, and innovation

## **Our Vision:** To be the most reliable, value-creating RTO




| MISO by-the-numbers | |
|---|---|
| High Voltage Transmission | 65,800 miles |
| Generation Capacity | 174,000 MW |
| Peak Summer System Demand (07-20-11) | 127,125 MW |
| Customers Served | 42 million |

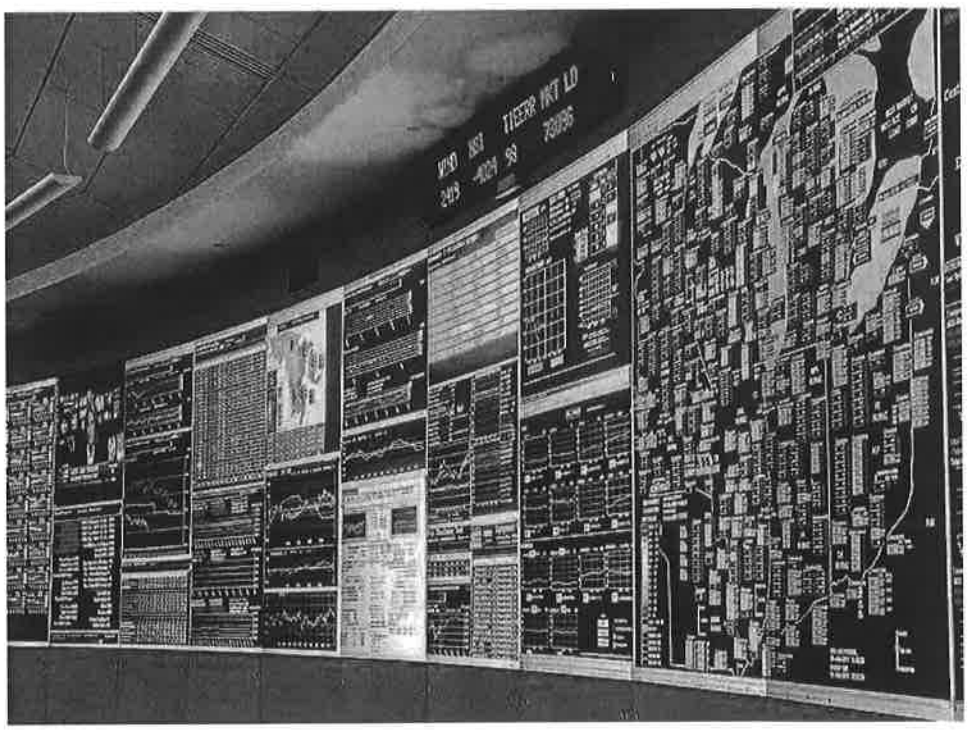


# MISO's Key Functions

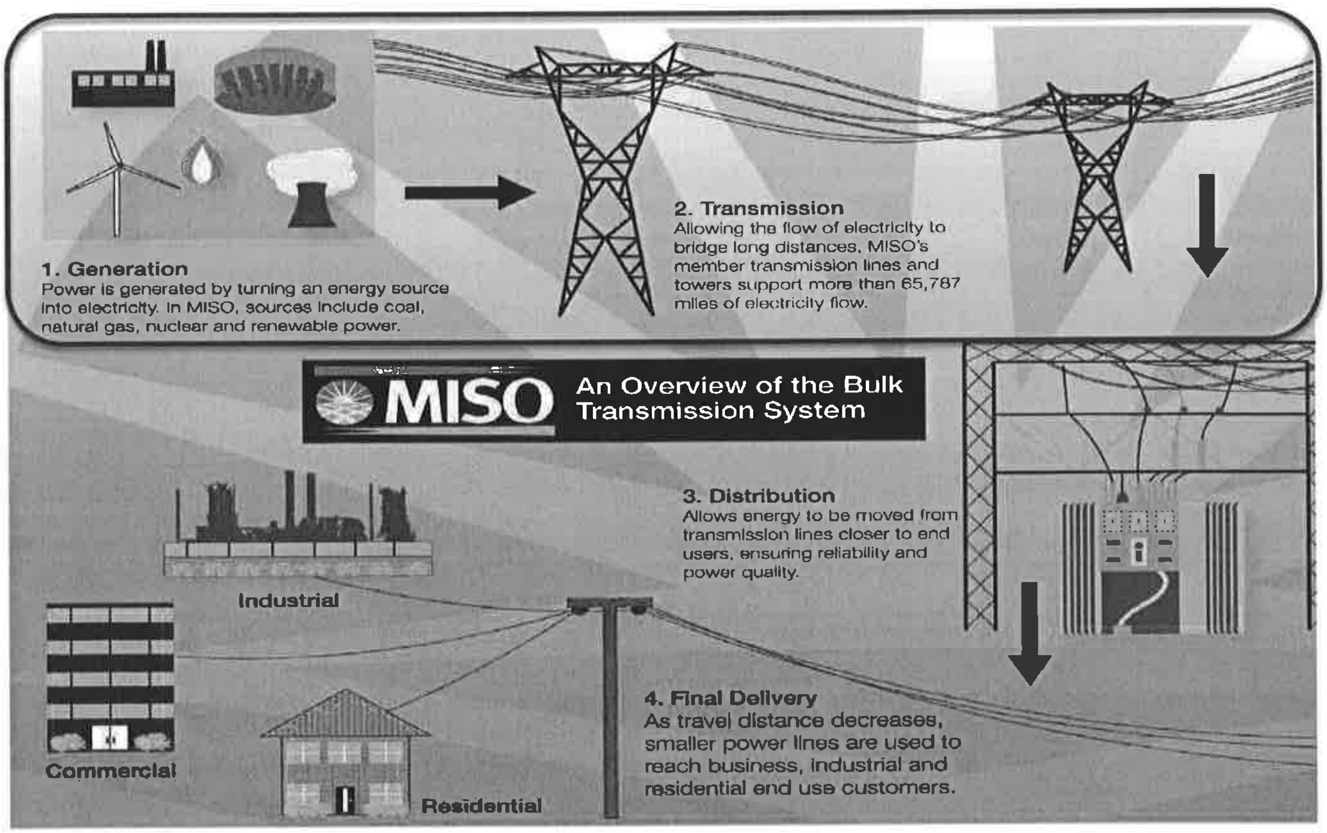
1. **Keeping the Lights On:** Safe and reliable operation of the electric grid

2. **Operating Open Energy Markets:** Scheduling and economic dispatch of generation to support reliability and efficiencies across the system

3. **Performing Transmission Planning:** Comprehensive expansion planning that meets reliability needs, policy needs, and economic needs



# MISO doesn't own any physical assets, we manage flows on the transmission system by directing generator usage



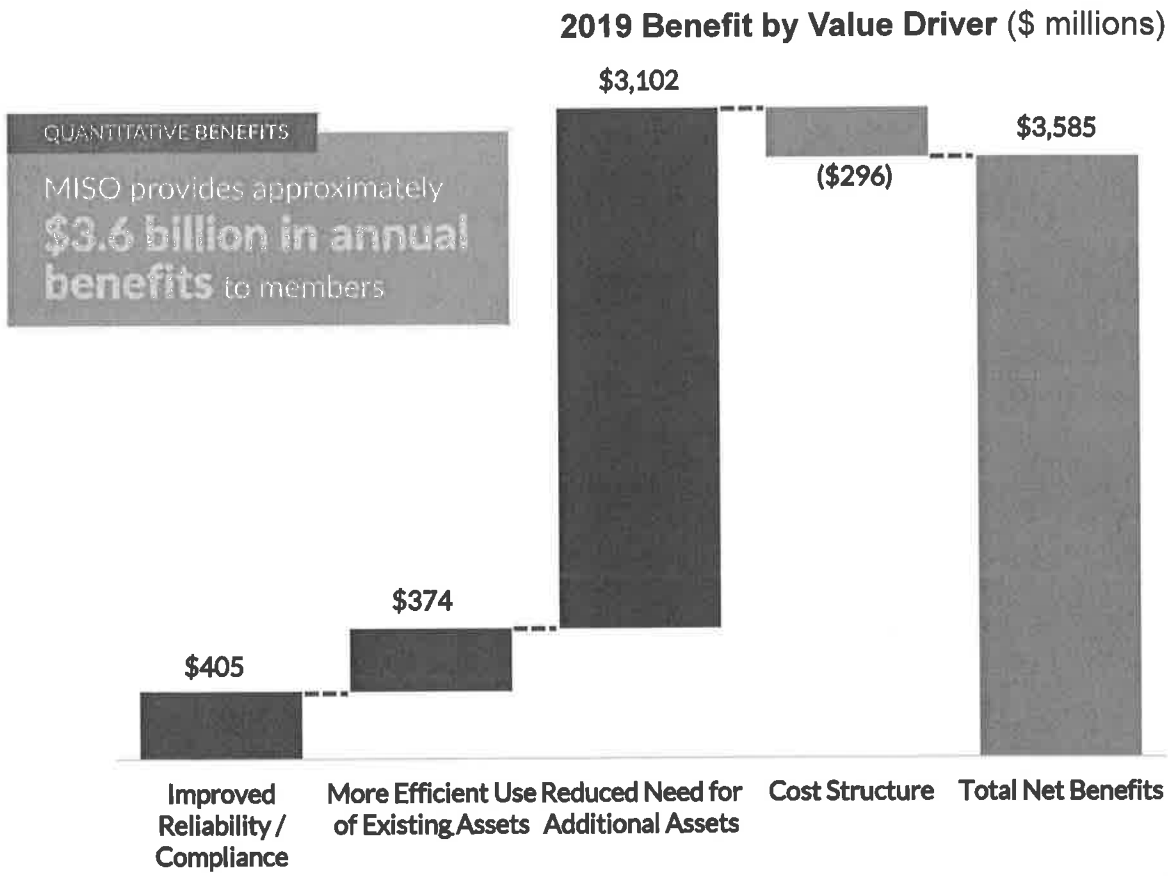
# MISO members participate across the electricity value chain


| | | | | | | |
|---|---|---|---|---|---|---|
| MISO 'Sectors': | Independent Power Producers | Competitive Transmission Developers | Transmission Owners | Power Marketers/ Brokers | Muni/Coop/ Transmission Dependent Utilities | Eligible End-User Customers |
| # of MISO members: | 29 | 30 | 51 | 36 | 31 | 9 |

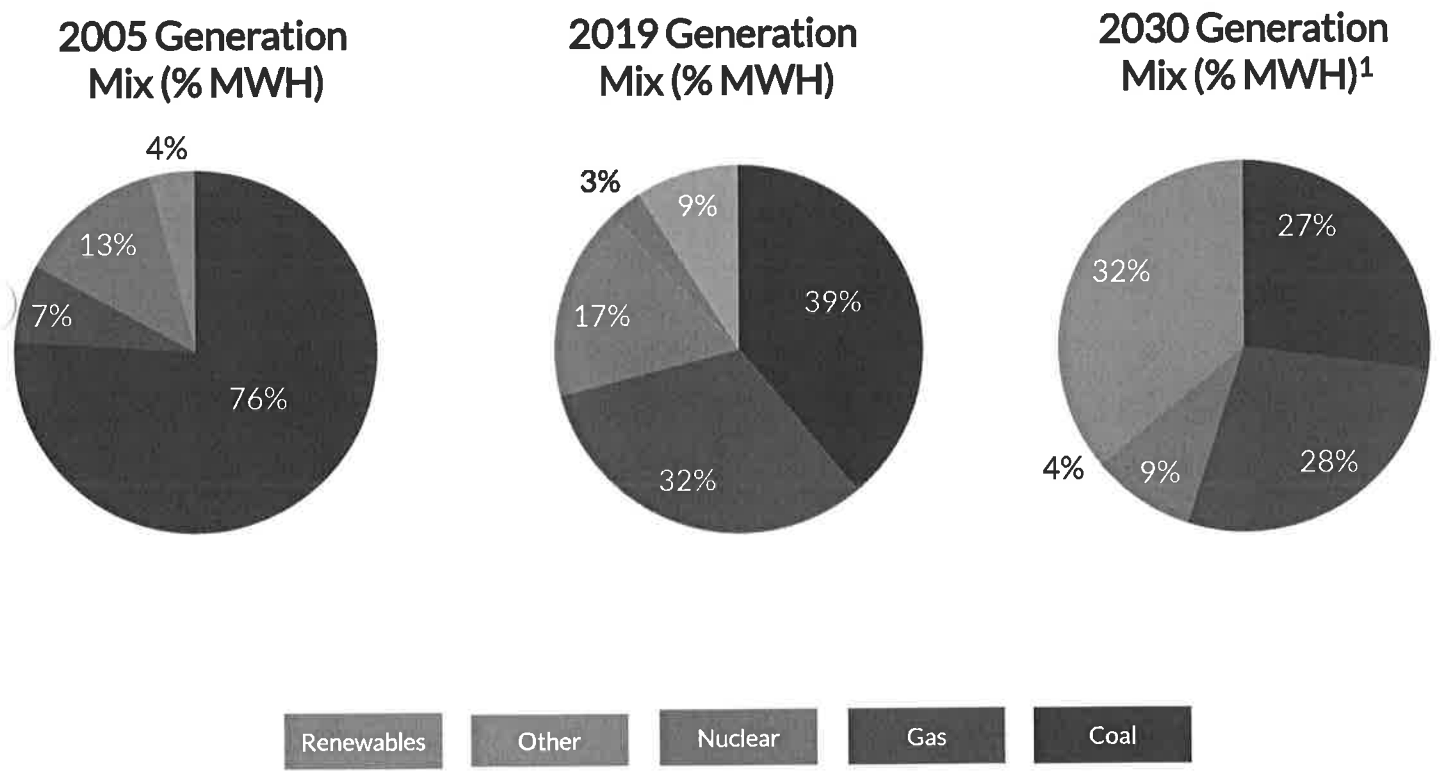


MISO

# Since 2009, MISO has estimated over $26 billion in membership benefits

# MISO will continue to support the evolution of resources on the bulk electric grid






[1]The 2030 projection compiled from Integrated Resource Plans , investor reports and other sources. Figures represent energy generated by fuel type, distinguished from capacity.

# Part II: MLGW Membership Assessment

## Siemens provided a list of study objectives and requested MISO's independent review

- Resource Adequacy:
  - Is the capacity expansion plan sufficient to join MISO Local Resource Zone (LRZ) 8 or to be a standalone Local Resource Zone?
  - What is the impact to the MISO Planning Reserve Margin (PRM)?
  - Is there adequate capacity for MLGW to purchase starting in 2025?
- Transmission Interconnection:
  - Is the transmission expansion proposal a reliable solution?
  - What is the MLGW import capability?
  - What is MISO's estimate of the costs for transmission expansion, reliability upgrades, and generator interconnections?
- Market Impact:
  - How will membership affect its Adjusted Production Costs (APC)?
  - What are the impacts to MISO's regional congestion patterns?
- MISO Cost:
  - What are the annual costs to MLGW of MISO membership?

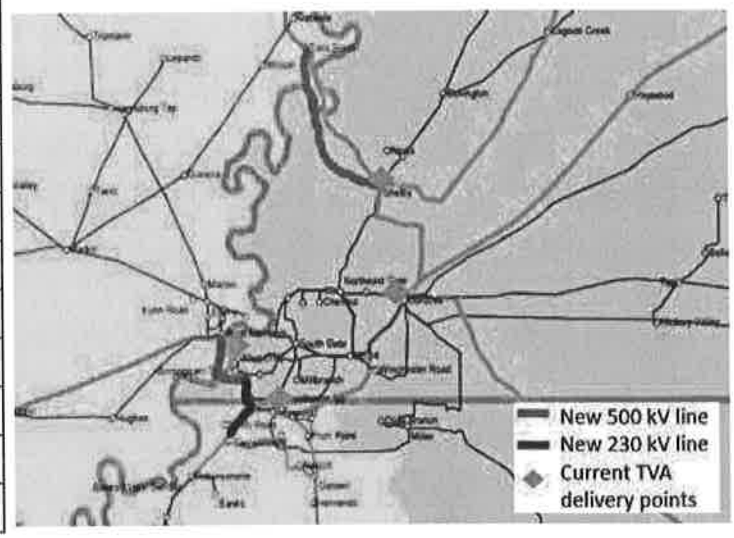
# MISO performed its assessment for MLGW based on the following capacity and transmission expansion plan

## Base Capacity Expansion Plan

| MW | Gas CT | Gas CC | MLGW Solar | Arkansas Solar | Arkansas Wind |
|---|---|---|---|---|---|
| 2025 | 237 | 1,350 | 600 | 500 | 200 |
| 2026 | 0 | 0 | 400 | 0 | 0 |
| 2027 | 0 | 0 | 0 | 0 | 0 |
| 2028 | 0 | 0 | 0 | 0 | 50 |
| 2029 | 0 | 0 | 0 | 0 | 50 |
| 2030 | 0 | 0 | 0 | 150 | 0 |
| 2031 | 0 | 0 | 0 | 50 | 0 |
| 2032 | 0 | 0 | 0 | 0 | 50 |
| 2033 | 0 | 0 | 0 | 50 | 0 |
| 2034 | 0 | 0 | 0 | 300 | 0 |
| 2035 | 0 | 0 | 0 | 0 | 0 |
| 2036 | 0 | 0 | 0 | 50 | 0 |

## Transmission Expansion Plan

- 500 kV line from San Souci – Shelby
- 500 kV line from West Memphis – New Allen
- 230 kV line from Twinkletown – New Allen



# The MLGW membership analysis resulted in the following takeaways

### RESOURCE ADEQUACY ASSESSMENT

- Siemens' proposal provides MLGW with adequate resources to join MISO Local Resource Zone (LRZ) 8 or to be its own standalone zone
- If MLGW were to join MISO it would lower the Installed Capacity (ICAP) Planning Reserve Margin (PRM) from 18.2% to 17.9%
- MISO is unable to provide direction on how much excess capacity would be available for purchase

### TRANSMISSION INTERCONNECTION ASSESSMENT / COST

- MISO validated the physical transmission import capability up to 2,400 MW during 2024 summer peak conditions
- MISO's estimated the transmission expansion, reliability upgrades, and interconnection costs to be $736.2M vs. $728.2M by Siemens[2]

### MARKET IMPACT ASSESSMENT

- MLGW could realize annual production cost savings of $92.6 million in 2024 to as much as $268.6 million in 2034 (note: these totals do not account for fixed costs)
- Projections show MLGW self supplying 50% of its energy needs in 2024 and increasing over time
- No significant changes to congestion patterns were observed

### MISO ADMINISTRATIVE COST RECOVERY FEES

- Based on a projection of MISO's annual operating expenses MLGW's share of MISO's costs would be approximately $6 million annually
- As a MISO member MLGW would be charged a portion of FERC's annual budget. This cost is estimated at an additional $730,000 per year.



[2]The Siemens cost estimate is adjusted to match MISO's assumptions regarding contingencies and inflation.

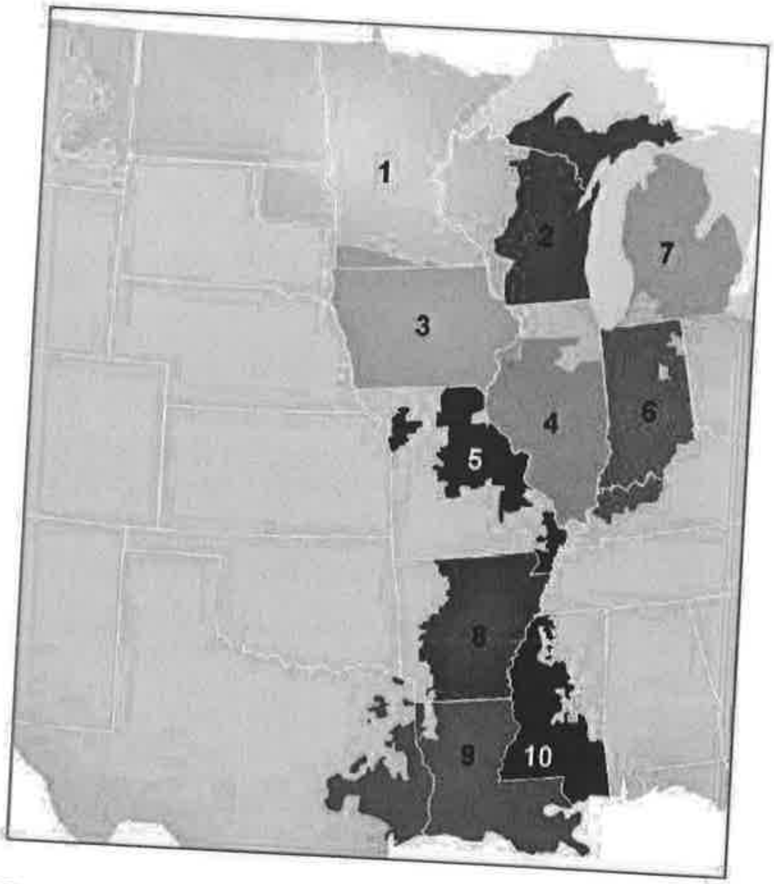
## MLGW has requested that MISO evaluate an additional option which includes no local generating resources

- MISO will be analyzing the same variables that were reviewed under the previous capacity/transmission expansion plan
  - Resource Adequacy
  - Transmission Interconnection Reliability
  - Transmission Interconnection Cost
  - Market Impacts
- MISO has committed to delivering the results of its analysis prior to MLGW's Integrated Resource Plan (IRP) being finalized in early July

# Appendix

# MISO Local Resource Zone (LRZ) Map

- MISO's footprint is divided into ten Local Resource Zones (LRZs)
- MISO developed LRZs to reflect the need for an adequate amount of planning resources to be located in the right physical locations within the MISO Region
- The geographic boundaries of the LRZs are based on multiple criteria



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# Strategies / Scenarios / Portfolio Analyzed

## Key Issue: Portfolio Expansion Strategies

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- The **Strategies**, representing the available options to MLGW to supply its load, are combined with **Scenarios** (i.e. future states of the world) and using a structured approach to identify Portfolios.

- Multiple Strategies were assessed:
  - Strategy 1: Full Requirements Contract with TVA
  - Strategy 2: Self-Supply (found to be impractical)
  - Strategy 3: MLGW-MISO combination with restricted transmission access ("No Deal" Case)
  - Strategy 4: All MISO

- Multiple Scenarios were developed for Strategy 3

- A least cost generation and transmission plan was developed for each Strategy/Scenario combination

| Scenarios / Portfolios | | Strategy | | |
|---|---|---|---|---|
| | | Strategy 1 (TVA) | Strategy 3 Self + MISO | Strategy 4 All MISO |
| State of the World | Scenario 1 Reference | S1S1 | S3S1 | S4S1 |
| | Scenario 2 (High Load) | | S3S2 | |
| | Scenario 3 (Low Load) | | S3S3 | |
| | Scenario 4 (High Load/Low Gas) | | S3S4 | |
| | Scenario 5 (High Transmission) | | S3S5 | |
| | Scenario 6 (Promote BESS) | | S3S6 | |
| | Scenario 7 (Low Load/High Gas) | | S3S7 | |

# Summary of the Selection of 11 Portfolios

| Portfolio ID | Final Portfolio | Load | Gas Price | Total Thermal 2039 | Local Renew 2039 | Battery 2039 | Total Local Nameplate 2039 | MISO Renew 2039 | MISO Cap 2039 | 950 MW CC | 450 MW CC | 237 MW CT | 343 MW CT |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| S3S1 | No | Base | Base | 1137 | 1000 | 0 | 2137 | 2200 | 1761 | 0 | 2 | 1 | 0 |
| S3S1_P | Portfolio 1 | Base | Base | 1137 | 1000 | 0 | 2137 | 2200 | 1761 | 0 | 2 | 1 | 0 |
| S3S7_BB | Portfolio 6 | Base | Base | 1137 | 1000 | 0 | 2137 | 2200 | 1761 | 0 | 2 | 1 | 0 |
| S3S1_2CT | Portfolio 7 | Base | Base | 1374 | 1000 | 0 | 2374 | 2200 | 1550 | 0 | 2 | 2 | 0 |
| S3S7_2CT | Portfolio 8 | Base | Base | 1374 | 1000 | 0 | 2374 | 2200 | 1550 | 0 | 2 | 2 | 0 |
| S3S1_M | No | Base | Base | 1930 | 650 | 0 | 2580 | 1050 | 1342 | 0 | 3 | 1 | 1 |
| S3S1_MP | No | Base | Base | 1587 | 750 | 0 | 2337 | 1800 | 1487 | 0 | 3 | 1 | 0 |
| S3S1_F | Portfolio 2 | Base | Base | 1587 | 1000 | 0 | 2587 | 1550 | 1487 | 0 | 3 | 1 | 0 |
| 1_A | No | Base | Base | 1587 | 1000 | 0 | 2587 | 1150 | 1554 | 0 | 3 | 1 | 0 |
| S2 | No | High | Base | 1824 | 1000 | 0 | 2824 | 1350 | 1746 | 0 | 3 | 2 | 0 |
| S3S2_BB | Portfolio 3 | Base | Base | 1824 | 1000 | 0 | 2824 | 1350 | 1308 | 0 | 3 | 2 | 0 |
| S3S3 | No | Low | Base | 1350 | 1000 | 0 | 2350 | 1550 | 1655 | 0 | 3 | 0 | 0 |
| S3S3_BB | Portfolio 4 | Base | Base | 1350 | 1000 | 0 | 2350 | 1550 | 1697 | 0 | 3 | 0 | 0 |
| S3S4 | No | High | Low | 1824 | 1000 | 25 | 2849 | 700 | 1849 | 0 | 3 | 2 | 0 |
| S3S5 | Portfolio 5 | Base | Base | 1398 | 1000 | 100 | 2498 | 3450 | 1183 | 0 | 1 | 4 | 0 |
| S3S5_YD | Portfolio 9 | Base | Base | 1398 | 1000 | 100 | 2498 | 3450 | 1186 | 0 | 1 | 4 | 0 |
| S3S6_N | No | Base | Base | 900 | 1000 | 475 | 2375 | 2200 | 1505 | 0 | 2 | 0 | 0 |
| S3S6 | No | Base | Base | 900 | 1000 | 475 | 2375 | 2200 | 1505 | 0 | 2 | 0 | 0 |
| S3S7 | No | Low | High | 1137 | 1000 | 0 | 2137 | 2200 | 1718 | 0 | 2 | 1 | 0 |
| S3S8 | No | Base | Base | 0 | 1000 | 0 | 1000 | 4850 | 2248 | 0 | 0 | 0 | 0 |
| S3S10 | Portfolio 10 | Base | Base | 950 | 1000 | 0 | 1950 | 2250 | 1909 | 1 | 0 | 0 | 0 |
| S4S1 | Portfolio All MISO | Base | Base | 950 | 0 | 0 | 0 | 3200 | 1909 | 1 | 0 | 0 | 0 |

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Recognizing that cost was not the sole basis for selecting Portfolios. The determination of the final Portfolios is a two-step process:

- First: a base capacity expansion is produced using the Long Term Capacity Expansion (LTCE) module of the optimization software (AURORA).

- Next: Expert judgement is used to adjust the initial expansion plan and the AURORA LTCE was re-run with these adjustments in place, resulting in a unique Portfolio that is better suited to manage risks, such as reduced dependence on remote resources.

# Metrics

## Objectives and Metrics Used in The Evaluation Of Alternative Portfolios

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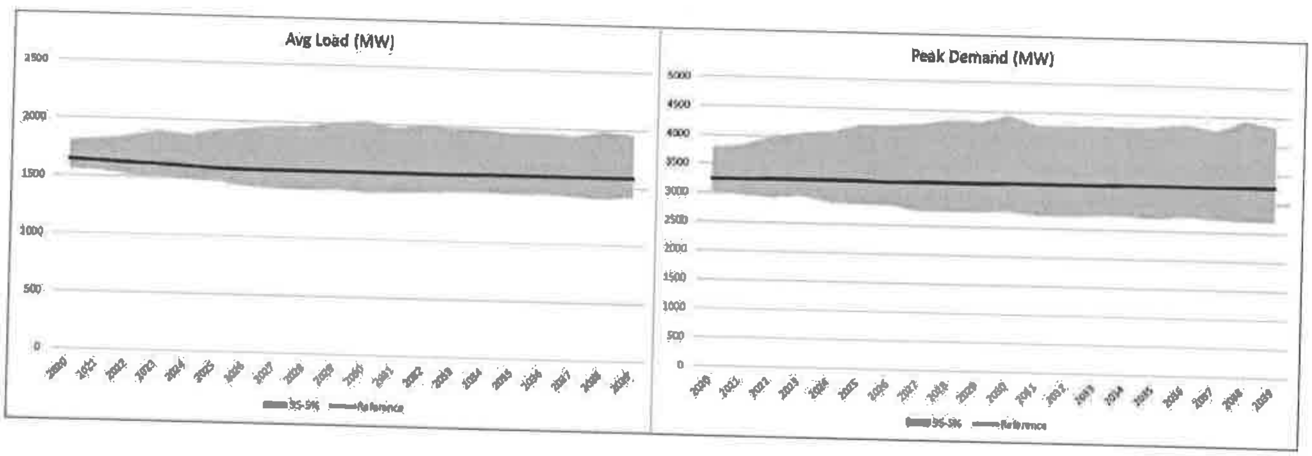
| OBJECTIVES | METRICS |
|---|---|
| **Reliability** | Meets or exceeds NERC reliability requirements and manages intermittency. All Portfolios meet the minimum levels of NERC thus the metric is designed to measure the ratio of Capacity Import Limit (CIL) + Generation Unforced Capacity (UCAP) to Peak Load. ***Higher the better.*** |
| **Least cost (Affordability)** | NPV of revenue requirements: this includes all costs in addition to the generation capital and operating costs, i.e. transmission, MISO Membership, TVA benefits, PILOT, etc. ***Lower the better.*** |
| **Price Risk (Minimization/Stability)** | Measured as: a) 95% (worst) outcome and b) Regret: i.e. the level by which MLGW would regret having chosen a Portfolio in case of an adverse future. ***Lower worst outcome and Minimum or No Regret is the goal.*** |
| **Sustainability** | Measured as a) Carbon (proxy for total emissions), b) water consumption and c) percentage of the energy coming from renewable resources (nuclear and large hydro excluded). ***On a & b lower the better , c higher the better.*** |
| **Market Risk** | Energy Market Purchases or Sales as a percentage of load; Amount of Capacity Purchases. ***Lower the better.*** |
| **Economic Growth** | Capital Expenditures in Shelby County and number of plants as a proxy. ***Higher the better.*** |
| **Resiliency** | Amount of load shed during extreme events. ***Lower the better.*** |

# Input Assumptions

## Memphis Stochastic Load




The overall distribution shows considerable uncertainty for future average load growth exceeding the reference case, and less uncertainty for future average load growth trending below the reference case.

## Natural Gas Price Outlook Cost Components: Henry Hub + Market Gas Hub Index + Transport Tariff

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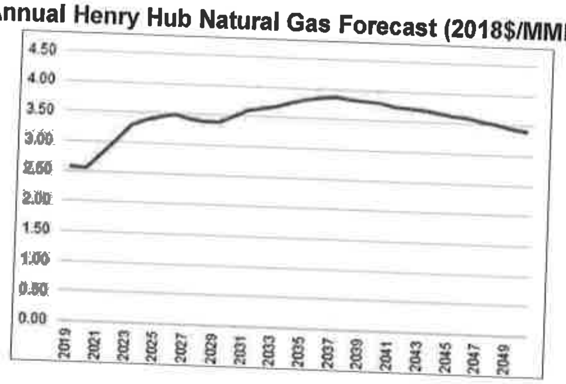
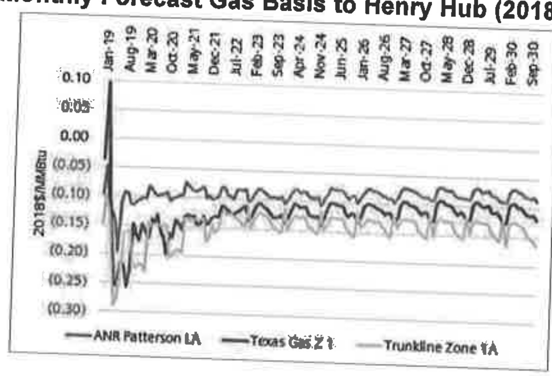
**Annual Henry Hub Natural Gas Forecast (2018$/MMBtu)**



**Monthly Forecast Gas Basis to Henry Hub (2018$/MMBtu)**




- The average of Trunkline Zone 1A and Texas Gas Z1 was used as the gas basis for gas plants built in MLGW territory.
- Trunkline firm transportation rate of $0.3811/MMBtu was used for combined cycles and interruptible transportation rate of $0.3212/MMBtu was used for gas peaker.

## Stochastic Inputs – Gas Prices

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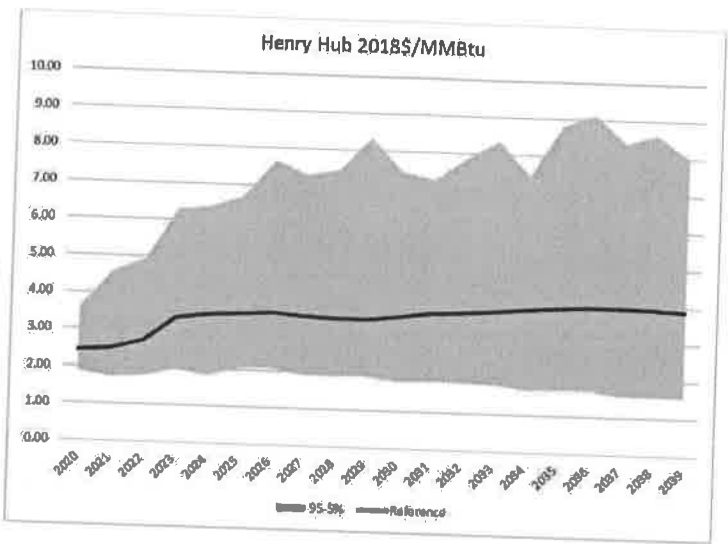


- Siemens has developed stochastics around the price at the Henry Hub based on historical volatility, current market forwards, and a long-term term fundamental view that considers the expected supply-demand balance.
- The 95th percentile probability bands are driven by increased gas demand (most likely due to coal retirements) and fracking regulations that raise the cost of producing gas.
- Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization down as well as little to no environmental legislation around power plant emissions.

## Stochastic Inputs – Coal Prices

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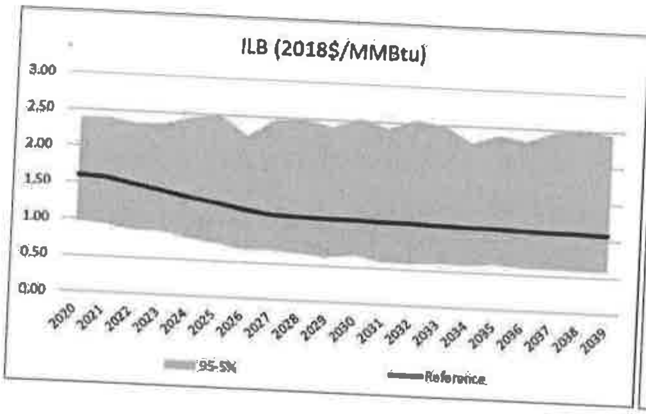


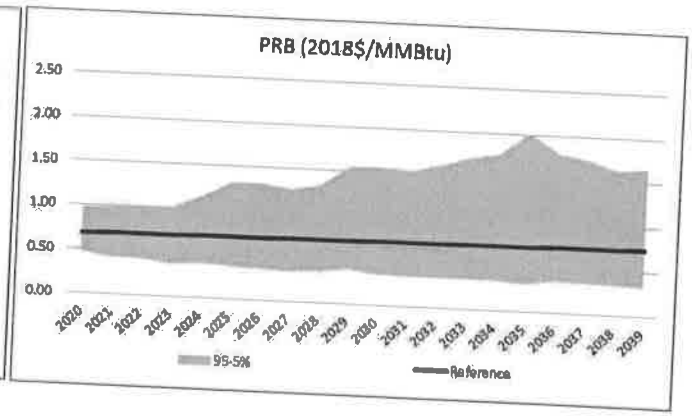


These stochastic distributions are based on a reference case view of coal prices with probability bands developed based on a combination of historical volatility and mean reversion parameters.

## Technology Options – Capital Costs

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| Technology | Advanced 2x1 CCGT | Conventional 1x1 CCGT, Duct Fired | Simple Cycle Advanced Frame CT | Simple Cycle Conventional Frame 7FA CT | Simple Cycle Aero CT | Coal With 30% CCS | Utility Solar PV - Tracking | Onshore Wind | Lithium Ion Batteries (4 hrs.) | Nuclear SMR |
|---|---|---|---|---|---|---|---|---|---|---|
| Fuel | Nat. Gas. | Nat. Gas. | Nat. Gas. | Nat. Gas. | Nat. Gas. | Coal | Sun | Wind | Elec. Grid | Uranium |
| Construction Time (Yrs.) | 3 | 3 | 2 | 2 | 2 | 5 | 1 | 2 | <1 | 7 |
| Size (MW) | 950 | 361 (Base) 89 (DF) | 343 | 237 | 50 | 600 | 50 | 100 | 5 MW / 20 MWh | 50-1,200 |
| Average Heat Rate (Btu/kWh), HHV | 6,536 | 7,011 (Base) 8,380 (Incr. DF) | 8,704 | 9,928 | 9,013 | 9,750 | N/A | N/A | N/A | N/A |
| VOM (2018$/MWh) | 1.81 | 2.49 | 7.13 | 5.05 | 6.50 | 7.14 | 0.00 | 0.92 | 1.39 | 14.79 |
| FOM (2018$/kW-yr) | 15.90 | 17.41 | 9.53 | 4.39 | 15.70 | 73.45 | 20.70 | 36.56 | 32.21 | 165.42 |
| Range of Capital Cost (2018$/kW) | 947-874 | 1084-1003 | 711-652 | 626-578 | 1136-1041 | 6135-5027 | 1245-702 | 1636-1399 | 1534-693 | 9539-5365 |
| Range of LCOE (2018$/MWh) | 35-51 | 42-58 | 95-112 | 88-110 | 140-155 | 98-101 | 38-29 | 37-28 | 151-84 | 124-86 |

- The technologies in red boxes were selected for Self-Supply + MISO Portfolios.
- Local solar has important advantages as it is closer to the load, behind the transmission constraints, and has lower transmission costs. Due to land availability, only 1000 MW was allowed to be built in Shelby County.
- Advanced 2x1 CCGT was removed from being built locally as an option due to reliability considerations; but remains a candidate for All-MISO Strategy.

# Stochastic Inputs – Technology Costs

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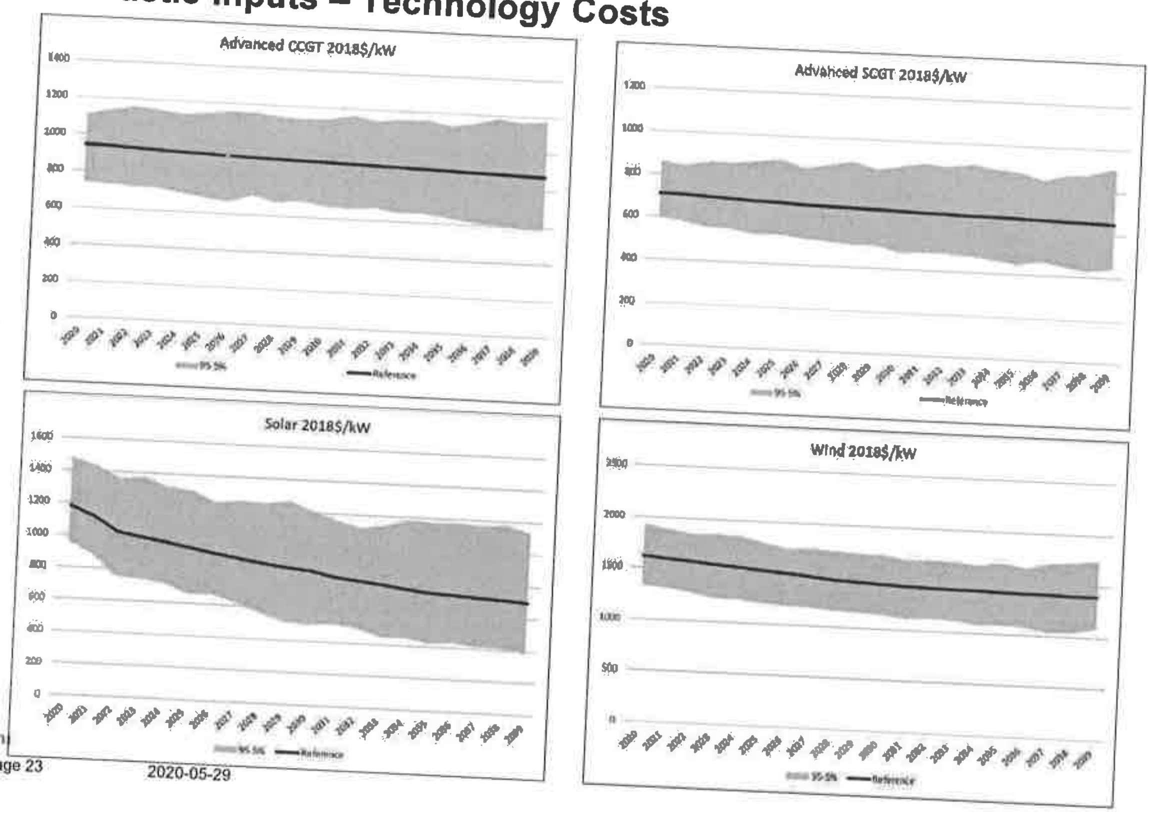

## Sustainability / Environmental Considerations

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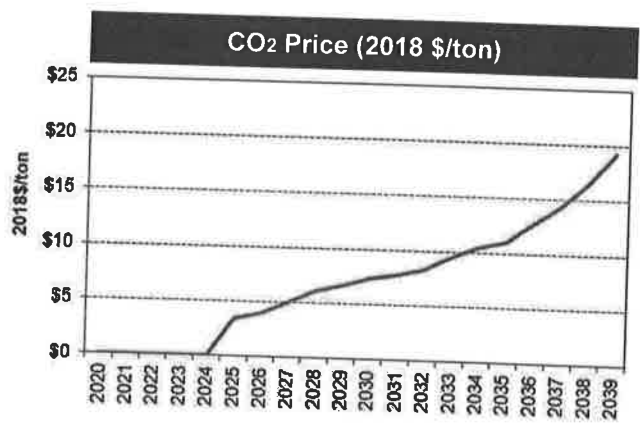
- Renewable standard was imposed at a minimal level. However, because renewable technologies were found to be an economic option, most portfolios included 50% or more renewable generation.
- A moderate federal price on carbon emissions was included in the Reference Case starting in 2025.
- Emission allowance price costs were included for existing market for $SO_2$ and $NO_x$.
- Permitting for new generation facilities was not conducted as a part of the IRP.
- High level assessment suggests that water access and air permits would be feasible for any large new gas generation facility in Shelby County.



## Stochastic Inputs – $CO_2$ Prices

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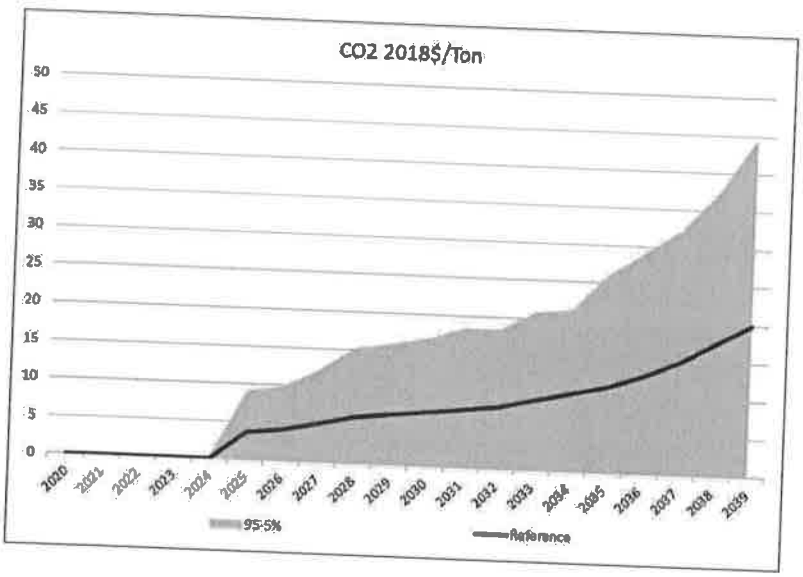


- Siemens developed uncertainty distributions around carbon compliance costs based on "expert-opinion" based projections, when the historical data is not available. The top end reflects estimates of the social cost of carbon.
- The distribution of carbon prices were used in the power dispatch modeling to capture the inherent risk associated with regulatory compliance requirements.

## Stochastic Inputs – Market Forecast

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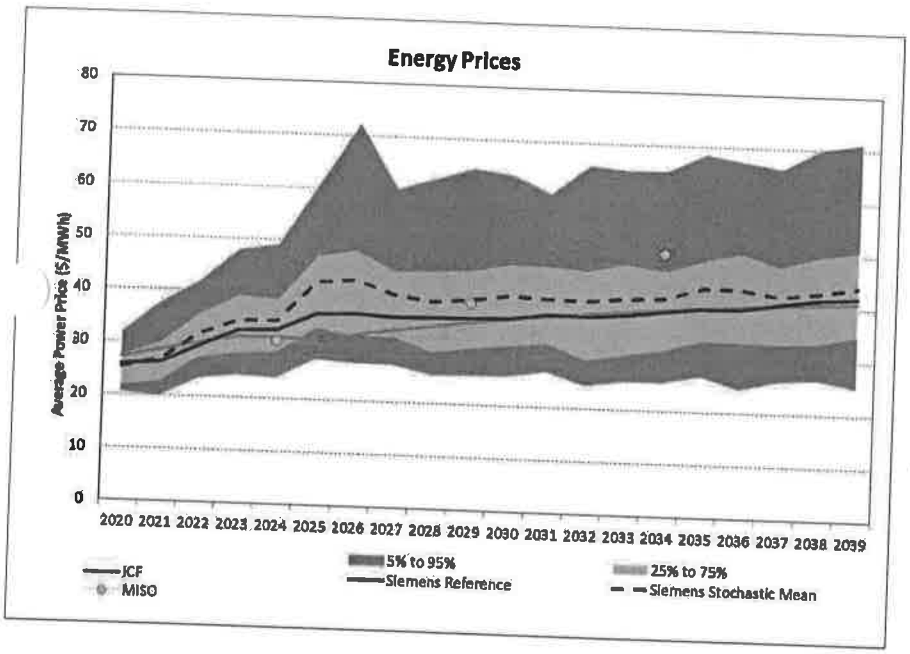


- Siemens also produces a range of views on how energy prices will change over the planning horizon.
- These are based on our forecast of future expansions.
- AURORA is used with all the input distributions to calculate energy prices.
- ICF and MISO forecasts are well within the bands of uncertainty evaluated. MISO is lower in the near term and higher in the long term.

# Resource Adequacy
# All Portfolios Must Meet MISO Resource Adequacy

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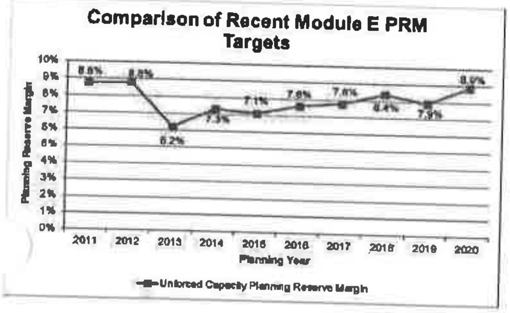


- MISO is planned so that there are enough reserves to ensure that the loss of load expectation (LOLE) is less than one day in 10 years
- Current requirement is 8.9% of Unforced Capacity (UCAP) or 18.2% considering the Installed Capacity (ICAP)
- To plan for this MISO is divided into 10 Local Resource Zones (LRZ)
- Each LRZ must have enough Local Resources so that with the ability to import resources from the rest of MISO (Capacity Import Limit – CIL) it meets the zone's criteria of 1 in 10. This is called the Local Reliability Requirement (LRR)

> - If MLGW were a new LRZ it would have a **LRR** of about 126%
> - If MLGW is part of LRZ-8 Arkansas this drops to about 120.6%

- Each LRZ must have internal resources so that it meets the larger of:
  a. MISO Planning Reserve Margin (PRM) of 8.9% (108.9% of peak load)
  b. The Local Clearing Requirement; which is the amount of internal generation (UCAP) that when added to the ability to import from MISO to meet the **LRR**
- All Portfolios that have internal generation were designed to meet:

**UCAP + CIL >= 126% of Peak Load**

## Transmission – The Proposed Plan and Analysis Performed

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- Transmission was planned under the assumption that TVA will not provide wheeling to MLGW for use of its transmission system, aka "No Deal"
- Strong interconnections must be established between MLGW and MISO if MLGW were to join MISO. This applies to Strategies 3 & 4.
- Baseline transmission interconnections consist of:
  1. New San Souci-MISO to Shelby-MLGW 500 kV line, 26 miles
  2. West Memphis-MISO to New Allen-MLGW 500 kV line, 8.5 miles
  3. Twinkletown-MISO to New Allen-MLGW 230 kV line, 8 miles
- Based on the LTCE plans and proposed transmission configurations, Siemens performed:
  - Steady state contingency analysis, using NERC TPL reliability standards confirming all system reliable, and identified local upgrades
  - Transfer analysis, determined import capabilities from 2579 MW to 3690 MW depending on the requirement by the Portfolio
  - Stability analysis, demonstrated system stable against critical faults
  - Economic nodal production cost analysis, showed no expected system congestion
- Maximum transmission option adds 4th interconnection line: Dell-MISO to Shelby-MLGW 500 kV, 44 miles, required for All MISO Strategy.

## Transmission – The Numbers

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- Total capital costs for baseline configurations ~$700 M (with contingency) in 2018 $ or $2.1/MWh NPV 2025-2039:
  - Transmission expansions, $376 M
  - Local 161 kV reinforcements, $184 M
  - Generator Interconnections, $88 M
  - Reimbursements to TVA for Allen CCGT reconnection and reliability upgrades, $47 M
- Maximum transmission option (for All MISO Strategy), adds ~$407 M for a total of $1,014 M, or $3.1/MWh NPV 2025-2039.
- Cost of transmission O&M for new facilities, 2.5% of capital cost, ~$9.4M/year, or $0.7/MWh for base plan and increased to $0.9/MWh for max transmission plan.
- Capital cost varies based on the import requirement of each Portfolio

***The transmission configurations, reliability performance, transfer capability, and cost estimation were all independently reviewed by MISO***

## Other Costs – Integral part of the total revenue requirement

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- Payment in Lieu of Taxes (PILOT)
  - MLGW assumes full responsibility of state and local PILOT
    - State PILOT assumes 5% of the wholesale power cost, ranging $2.3/MWh to $2.6/MWh, or avg. $33 M /year, depending on the NPVRR of the Portfolio
    - Local PILOT ranges $1.4/MWh to $2.3/MWh depending on the total transmission investments
- TVA Service and Benefits Replacements
  - TVA has been providing social and economic benefits to Memphis area
  - MLGW is expected to continue those benefits and spend $13 to $15 million per year, or $1/MWh on the NPV basis.
- MISO Membership Cost
  - MLGW would be responsible for MISO membership fee and annual cost shares at about $6.7 million per year or $0.45/MWh on the NPV basis.
- Energy Efficiency Programs
  - MLGW is assumed to implement system wide energy efficiency programs to achieve 0.5% penetration at a cost of ~$ 7 million per year or $0.64/MWh on the NPV basis.

## Gap Analysis

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| Local Balancing Area Costs | |
|---|---|
| **Fixed Capital Cost (2020 $M)-LBA** | |
| AGC to MLGW controlled units | $0.8 |
| Data communications to generators and LBA service provider | $1.2 |
| Control center facility upgrade | $1.0 |
| Real-time contingency and reliability analysis | $0.8 |
| CIP compliance upgrade | $0.8 |
| TOTAL | $4.6 |
| | |
| **Annual O&M Cost (2020 $M, with annual escalator)-LBA** | |
| Annual LBA service vendor | $0.8 |
| LBA service technical support at MLGW | $0.4 |
| Expanded CIP Scope | $0.2 |
| Staff (+3) and training | $0.8 |
| Additional communications maintenance and fees | $0.4 |
| Additional control center systems maintenance | $0.4 |
| TOTAL | $3.0 |

- Siemens reviewed MLGW's existing capabilities and assessed the gaps for enabling MLGW to perform required planning and operating functions as a MISO LBA.
- The Gap Analysis referenced NERC reliability standards assigned to Balancing Authorities (BAs), and examined NERC's operations readiness (BA Certification) document. Additionally, the review included an analysis of the MISO Operating Agreement, last amended in January 2019.
- The total cost is about $0.5/MWh on NPV 2025-2039.

| Gap Cost - Other | YR 1 | YR 2 | YR 3 | YR 4 | YR 5 | YR 6 | YR 7 | YR 8 | YR 9 | YR 10 | Steady State---> |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Resource and Transmission Planning, Studies and Procurement | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
| Resource Planning Staff | 1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Transmission Planning and Interconnection Study Staff | 1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Procurement Staff | 1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 1 | 1 | 1 |
| Total Staff | 3 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 5 | 5 | 5 |
| Staffing Costs $266,000/FTE including salary, benefits, rent, facilities | $0.8 | $1.6 | $1.6 | $1.6 | $1.6 | $1.6 | $1.6 | $1.6 | $1.3 | $1.3 | $1.3 |
| Contractor & Consulting Costs, G&T MLGW | $0.5 | $0.8 | $1.0 | $1.0 | $1.0 | $1.0 | $1.0 | $0.5 | $0.5 | $0.3 | $0.3 |
| Total Cost | $1.3 | $2.4 | $2.6 | $2.6 | $2.6 | $2.6 | $2.6 | $2.1 | $1.8 | $1.6 | $1.6 |

*All staff are in addition to existing staff
*costs start 2021

*All Costs in Million

# Analyses of Portfolios

# Balanced Scorecard: Portfolios 9 and 10 of Strategy 3 Perform Best Across All Metrics

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| Objective | Measure | Unit | TVA (Base) | TVA (LTP) | Portfolio 5 | Portfolio 9 | Portfolio 10 | Portfolio 6 | Portfolio 8 | All MISO | Portfolio 1 | Portfolio 7 | Portfolio 4 | Portfolio 2 | Portfolio 3 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 1 CC + 4 CT | 1 CC + 4 CT | 1 CC + 0 CT | 2 CC + 1 CT | 2 CC + 2 CT | 1 CC + 0 CT | 2 CC + 1 CT | 2 CC + 3 CT | 3 CC + 1 CT | 3 CC + 2 CT | 3 CC + 0 CT |
| Least Cost | NPVRR 2020 - 2039 | $ Millions | 16,411 | 16,020 | 14,504 | 14,453 | 14,304 | 14,614 | 14,627 | 14,522 | 14,490 | 14,503 | 14,511 | 14,668 | 14,709 |
| Least Cost | Stochastic Mean NPVRR 2020 - 2039 | $ millions | 16,388 | 15,996 | 14,459 | 14,465 | 14,571 | 14,747 | 14,766 | 14,789 | 14,790 | 14,808 | 15,052 | 15,076 | 15,203 |
| Least Cost | Levelized Cost of Energy | $ / MWh | 67.47 | 65.86 | 59.32 | 59.34 | 59.48 | 60.51 | 60.59 | 60.68 | 60.69 | 60.76 | 61.77 | 61.87 | 62.39 |
| Least Cost | NPV Savings with respect of LTP (wrt LTP) 2020 -2039 | $ Millions | | | **1,537.4** | **1,531.7** | 1,425.9 | **1,249.3** | **1,230.5** | **1,207.8** | **1,206.8** | **1,188.0** | **944.7** | **920.2** | 793.0 |
| Least Cost | Levelized Savings per Year (wrt LTP) 2025 -2039 | $ Millions | | | **122.1** | **121.7** | 113.3 | 99.2 | **97.8** | **96.0** | **95.9** | **94.4** | **75.0** | **73.1** | **63.0** |
| Least Cost | Levelized Savings per Year (wrt Base) 2025 -2039 | $ Millions | | | **153.2** | **152.8** | **144.4** | 130.3 | **128.8** | **127.0** | **127.0** | 125.5 | **106.1** | **104.2** | 94.1 |
| Min Risk | 95th Percentile Value of NPVRR | $ millions | 17,221 | 16,830 | 16,576 | 16,517 | 16,993 | 16,946 | 16,944 | 17,211 | 17,051 | 17,074 | 17,648 | 17,535 | 17,844 |
| Min Envr. Risk | $CO_2$ Emissions Mean 20-Year | Million Tons $CO_2$ | 3.8 | 3.8 | 1.85 | 1.85 | 2.81 | 2.57 | 2.57 | 2.81 | 2.57 | 2.57 | 3.29 | 3.29 | 3.30 |
| Min Envr. Risk | Energy from Renewable Sources 2039 (RPS) | % of Energy Consumed | 6.5% | 6.5% | 75.3% | 75.3% | 52.7% | 54.9% | 54.9% | 52.7% | 56.8% | 56.8% | 47.3% | 46.1% | 40.7% |
| Min Envr. Risk | Energy from Zero Carbon Sources 2039 | % of Energy Consumed | 58.6% | 58.6% | 75.3% | 75.3% | 52.7% | 54.9% | 54.9% | 52.7% | 56.8% | 56.8% | 47.3% | 46.1% | 40.7% |
| Min Envr. Risk | 2025 Local Water Consumption | Million Gallon | 3,103 | 3,103 | 3,961 | 3,782 | 4,899 | 4,782 | 4,789 | 3,103 | 4,788 | 4,795 | 5,645 | 5,551 | 5,607 |
| Reliability | 2025 (UCAP+CIL)/PEAK | % | 133.7% | 133.7% | 126.0% | 127.8% | 148.6% | 126.6% | 127.2% | 115.4% | 126.6% | 127.2% | 126.7% | 130.8% | 137.3% |
| Resiliency | Max Load Shed in 2025 under Extreme Event | MW | 0 | 0 | 622.4 | 0.0 | 0.0 | 8.4 | 0.0 | 0.0 | 8.4 | 0.0 | 0.0 | 0.0 | 0.0 |
| Min Market Risk | % Energy Purchased in Market | % | 10.9% | 10.9% | 31.2% | 31.2% | 23.0% | 17.4% | 16.2% | 16.7% | 16.7% | 15.6% | 7.4% | 7.0% | 7.7% |
| Min Market Risk | % Energy Sold in Market | % | 8.7% | 8.7% | 22.6% | 22.6% | 17.9% | 9.7% | 9.7% | 10.5% | 10.5% | 10.6% | 7.6% | 6.7% | 5.6% |
| Econ. Growth | Local T&G CapEx | $ Millions | | | 2,989 | 2,864 | 2,984 | 2,845 | 2,965 | 1,014 | 2,811 | 2,932 | 3,138 | 3,299 | 3,404 |



*All $ is in 2018$ unless otherwise noted.

## Evaluation of Strategies 3 and 4: Portfolios 5, 6, 9 and 10 are Lowest Cost

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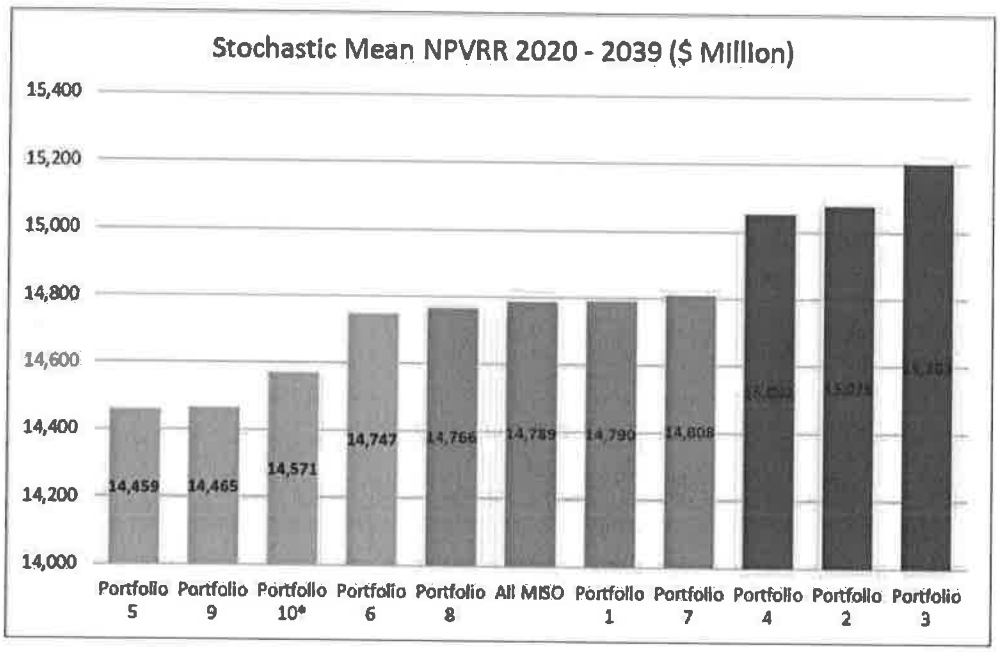


- Portfolios 5 and 9 have one 450 MW CCGT and Portfolio 10 has one 950 MW CCGT.
- Portfolio 6 has two 450 MW CCGTs.
- Other Portfolios with two CCGTs are close and Portfolio 6 is representative.
- Portfolios in blue are preferred.

## Evaluation of Strategies 3 and 4:
## Portfolios 5, 6, 9 and 10 are among the Lowest Risk

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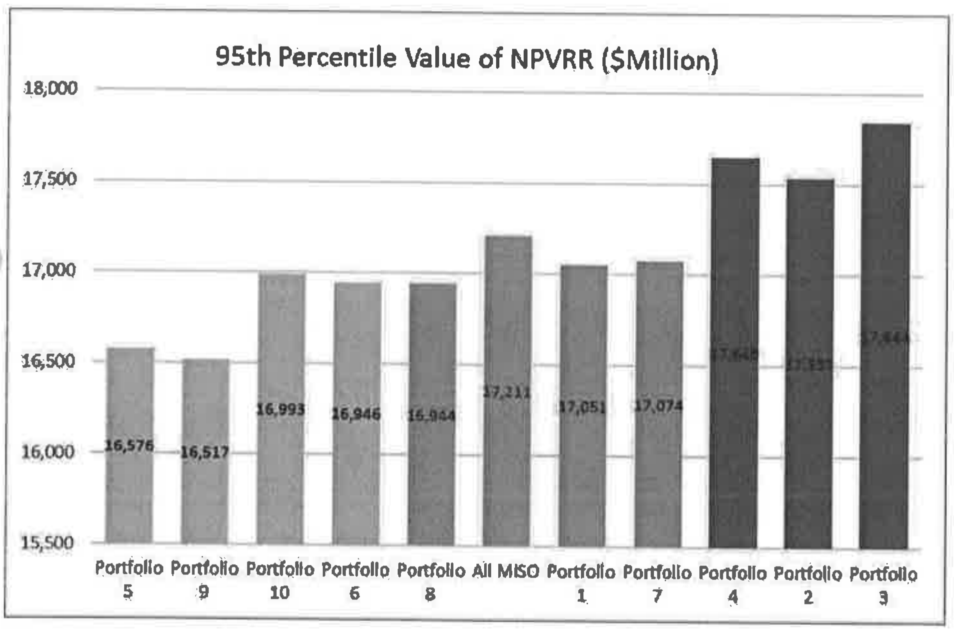


- Portfolios 10 and 6 show the higher risk among the preferred portfolios in blue.
- Risk is measured as the value that only 5% of the outcomes in the stochastic assessment was worse.

# Four Portfolios Selected for Comparison with TVA Portfolios 5, 6, 9 and 10.

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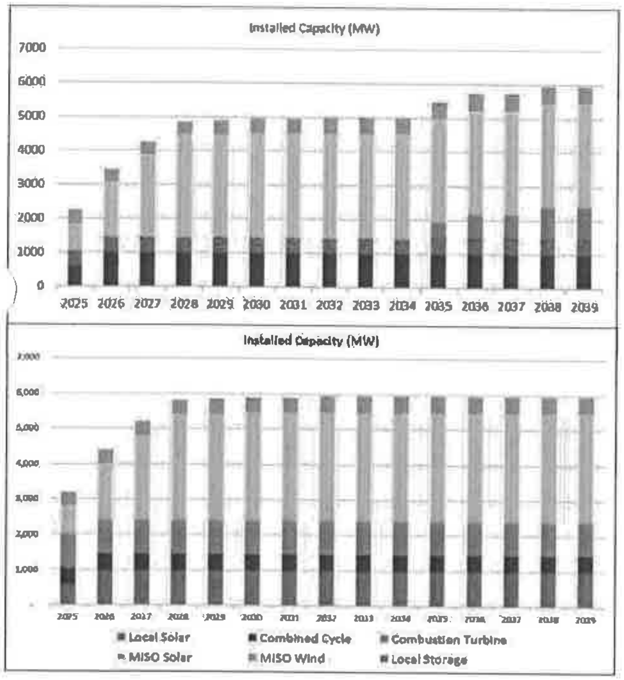


Portfolio 5

- Has the largest amount of renewable generation with 4,450 MW, most of which (4,400 MW) by 2028.
- Has one 450 MW CCGT in 2025.
- Four CTs (4x237 MW) are selected optimally as the price in MISO capacity increases.
- Requires heavy investments in transmission.

Portfolio 9

- Has the same level of renewable generation as Portfolio 5 and the CCGT.
- The four CTs are advanced to 2025 to address reliability concerns with Portfolio 5.
- Requires less investments in transmission.

# Four Portfolios Selected for Comparison with TVA Portfolios 5, 6, 9 and 10.

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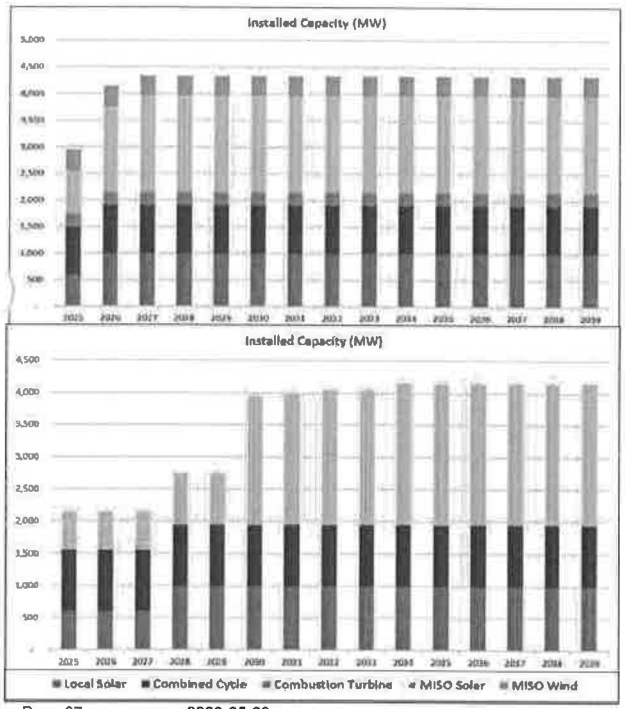


Portfolio 6

- Has 3,200 MW of renewable generation, all of which by 2027.
- Has two 450 MW CCGTs in service by 2025
- Has one CT (237 MW) by 2025
- Moderate investments in transmission

Portfolio 10

- Has 3,200 MW of renewable generation, most of which (3,000 MW) by 2030.
- Has one large 950 MW CCGT in 2025
- No CT
- Max investments in transmission to address reliability concerns due to one large CCGT

## Exiting TVA Could Save MLGW $1.5 Billion over 20 Years Considering the LTP and $ 1.9 Billion with Current Contract

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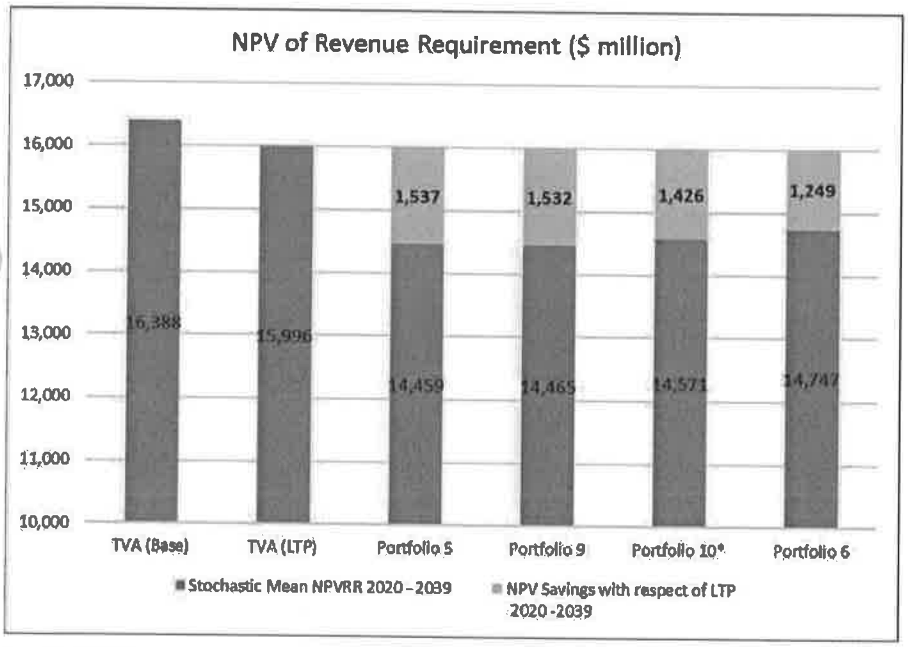


The savings are in real 2018$

- If expressed in 2020$ this would increase to $1.6 billion with respect of the LTP and $ 2.0 with respect of current contract.
- These savings are after all other costs are included.
- In nominal terms the savings add to over $ 3 billion with respect to the current contract.

# Exiting TVA could result in annual savings of about $120 million per year (2025-2039) with LTP to about $150 million per year (2025-2039) with current contract

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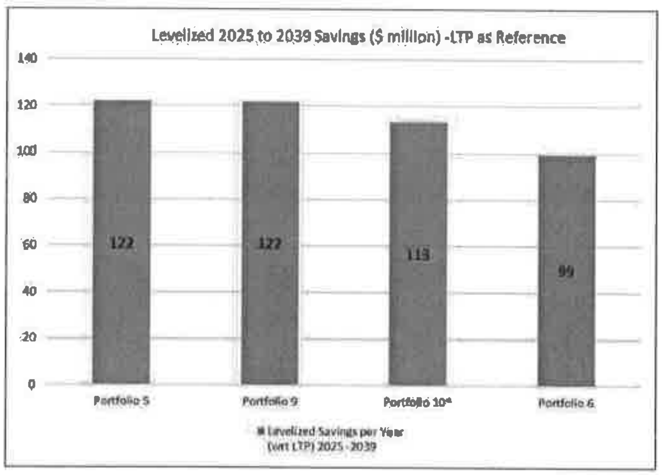


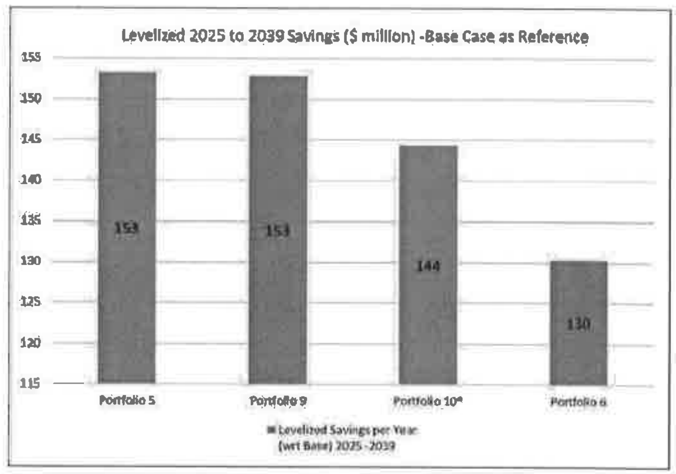


- There are potential savings of over $ 3.0 billion for the 2025 to 2039 period in nominal terms and with respect of the current contract. This averages to $ 200 million per year.

## 95th % NPVRR Risk Higher with TVA than Self Supply + MISO Options

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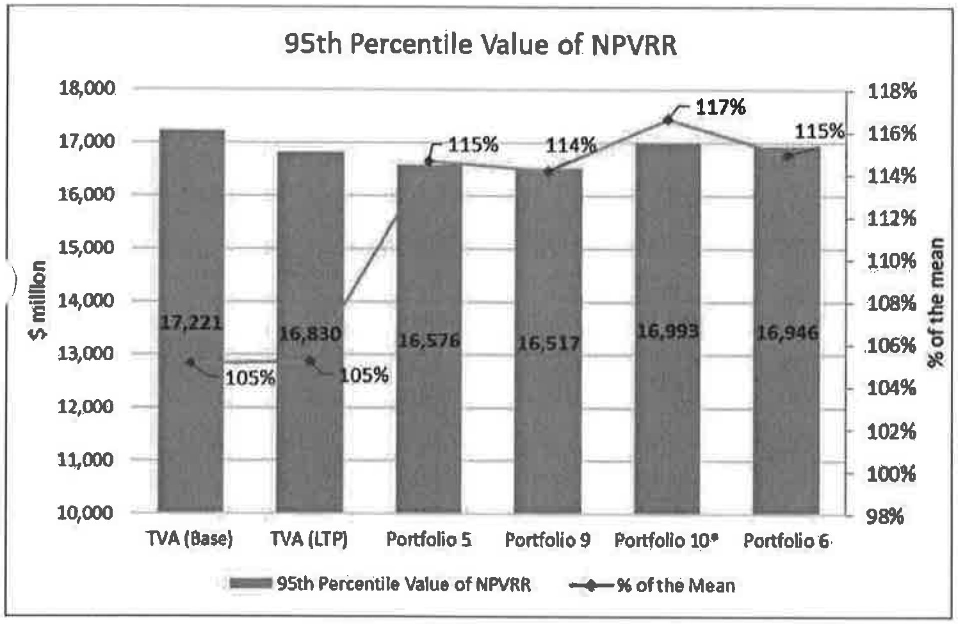


- The TVA option, given the size of the company and strong presence of nuclear and hydro that experience little or no volatility in costs, has more stable cost
- The 95th percentile of TVA portfolios is only 105% times the mean, while in other portfolios this reaches 114% to 117% times.
- Portfolios 5 & 9 are still least cost.
- It is important for MLGW to manage this volatility in costs by entering into, for example, long term fuel supply contracts.

# $CO_2$ Emissions from Self-Supply + MISO options are well below TVA options

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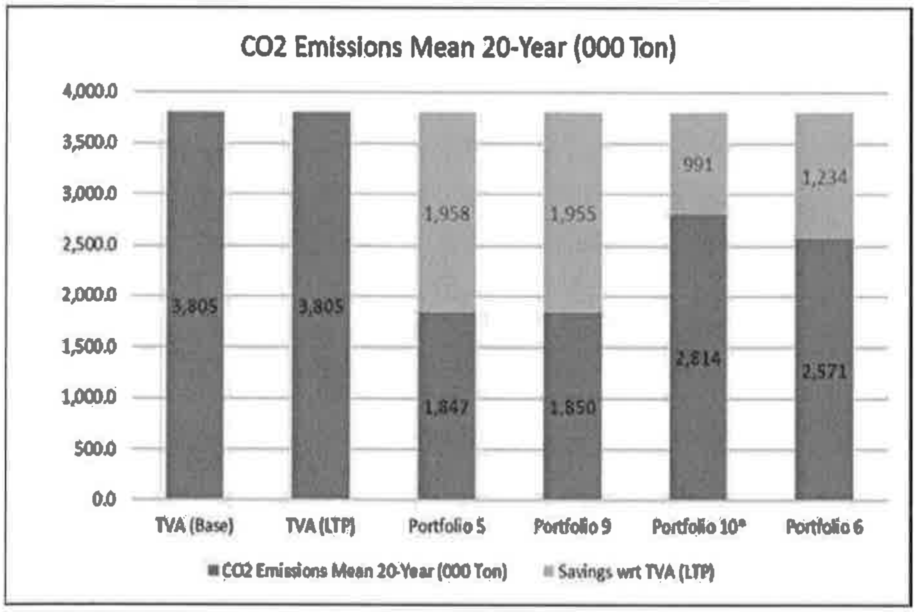

# Self-Supply + MISO Options Can Produce more Energy (Portfolios 5 and 9) from Zero Carbon Sources than TVA

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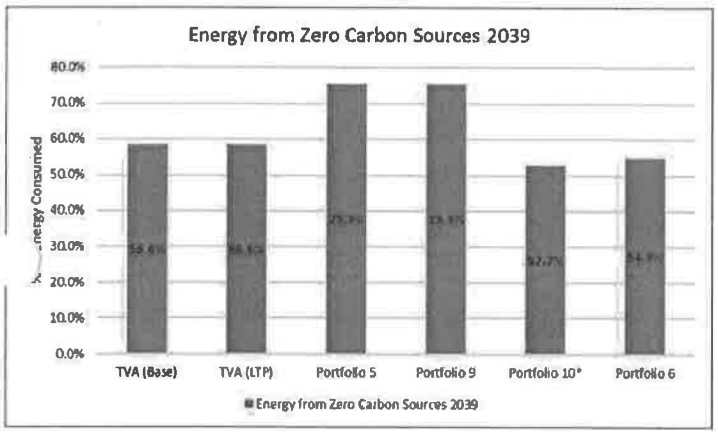


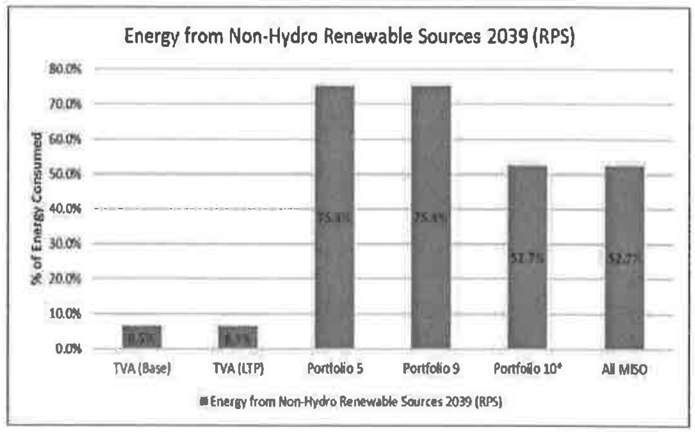


- TVA portfolio has lower renewable generation due to large hydro and nuclear being excluded.

## Shelby County Water Consumption is Lowest with TVA Options

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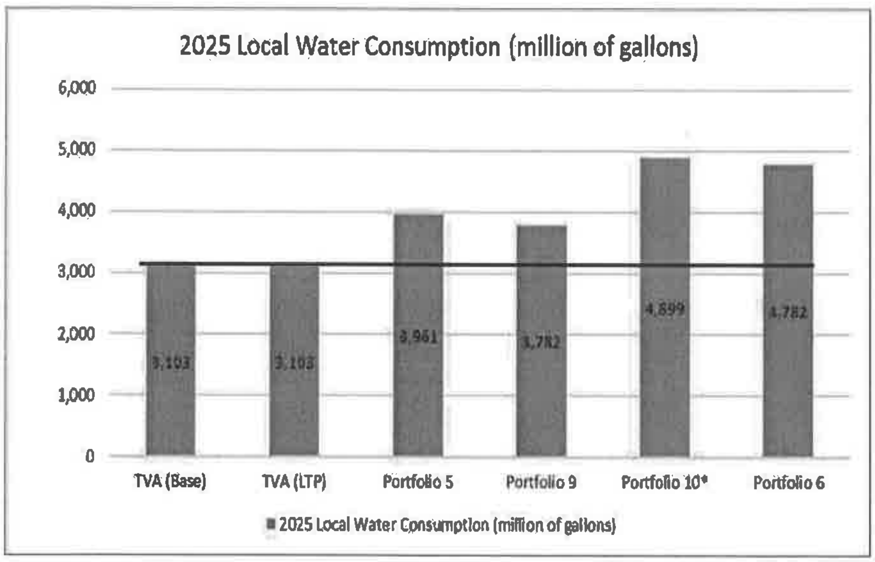


- These are the water usage for cooling thermal generation
- In case of TVA, the consumption is only by the Allen Combined Cycle
- Any other thermal generation adds to it.

## All the Portfolios Meet Minimum Reliability Requirements Portfolio 5 is Less Desirable Because of Potential Load Shedding

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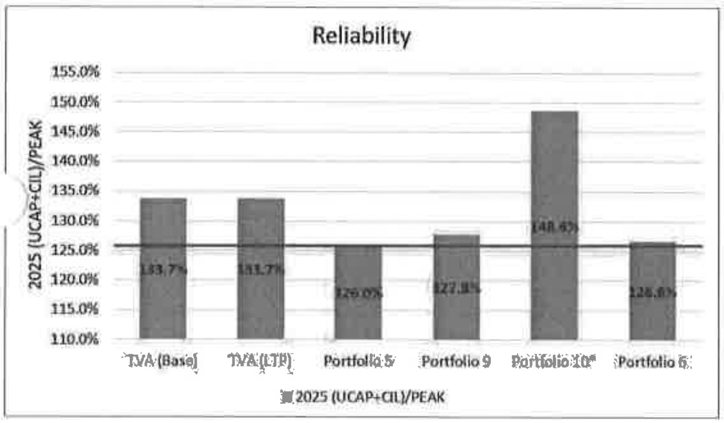


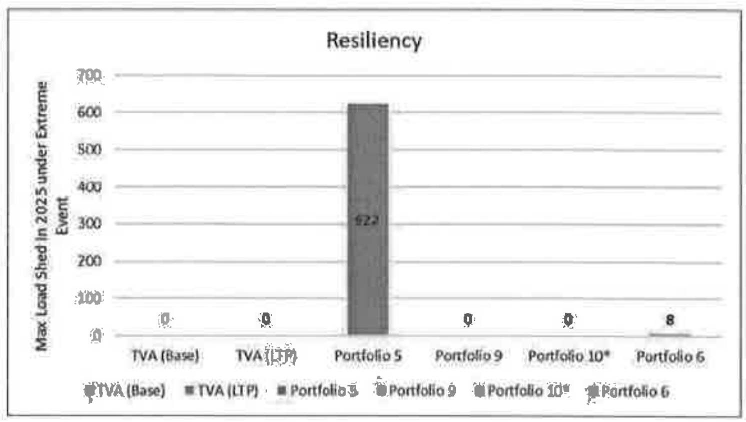

## TVA Has Less Exposure to Energy Market Risk
## Portfolios 5 and 9 Have the Greatest Exposure

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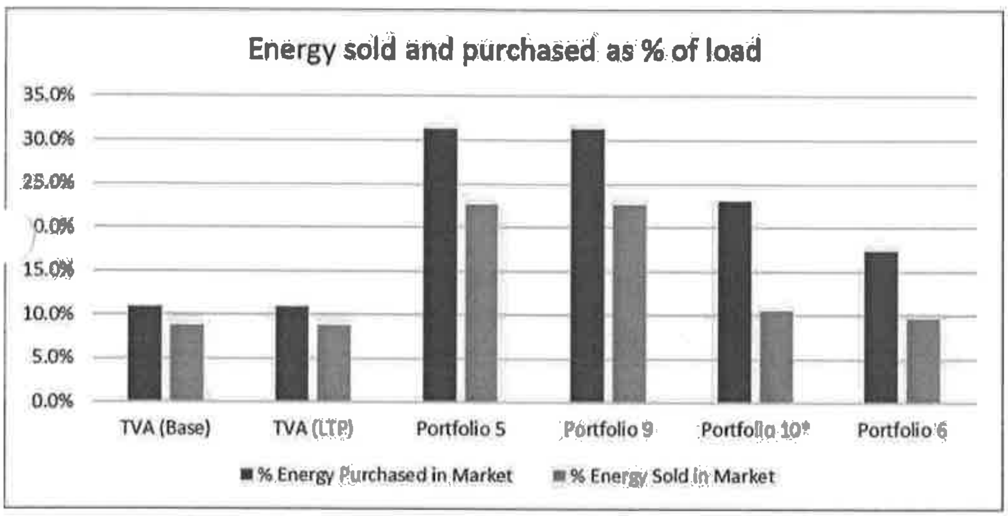


- Portfolios 5 and 9 with high levels of renewable have the greatest amounts of energy exchanged with MISO.
- Sales during the day and purchases at night.

## Economic Development (as expressed by local investment) Impacts are Similar Among Portfolios

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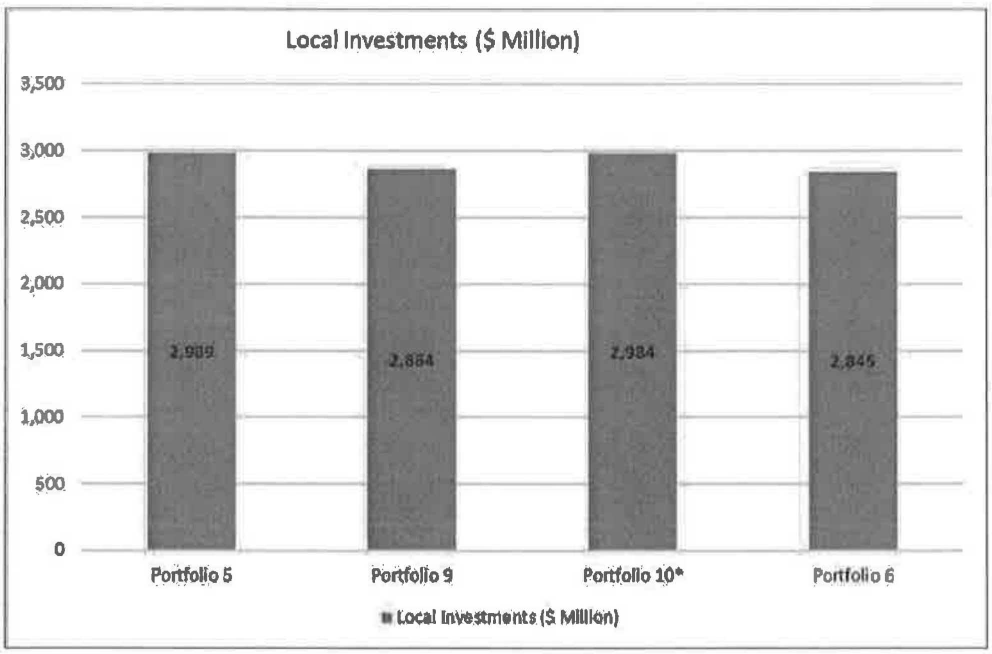

# Summary of Comparisons with TVA

## Focusing on the period after notice is given, the waterfall shows savings (2025-2039) with respect of the TVA LTP contract compared with Portfolio 9

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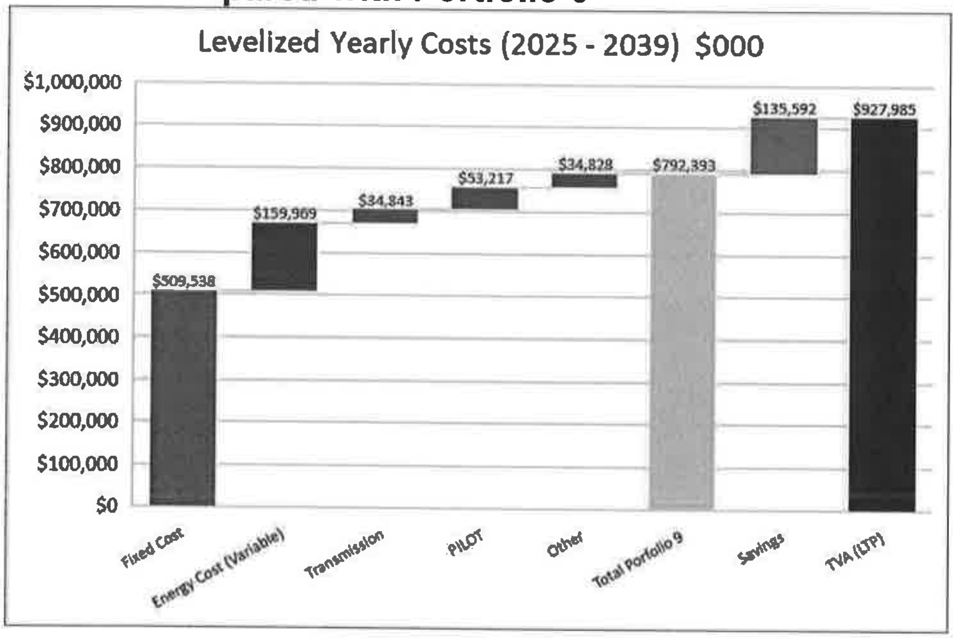


- The waterfall (buildout) shows the importance of the relative components of cost for Portfolio 9.
- The transmission and other costs are important. They contribute over $122 million/year to the comparable cost for TVA.
- This highlights the importance of assumptions.
- The savings are determined looking only at the difference in NPVs for the 2025 to 2039 period

## Focusing on the period after notice is given, annual savings for exiting TVA's current (5 year exit) contract (2025-2039) compared with Portfolio 9

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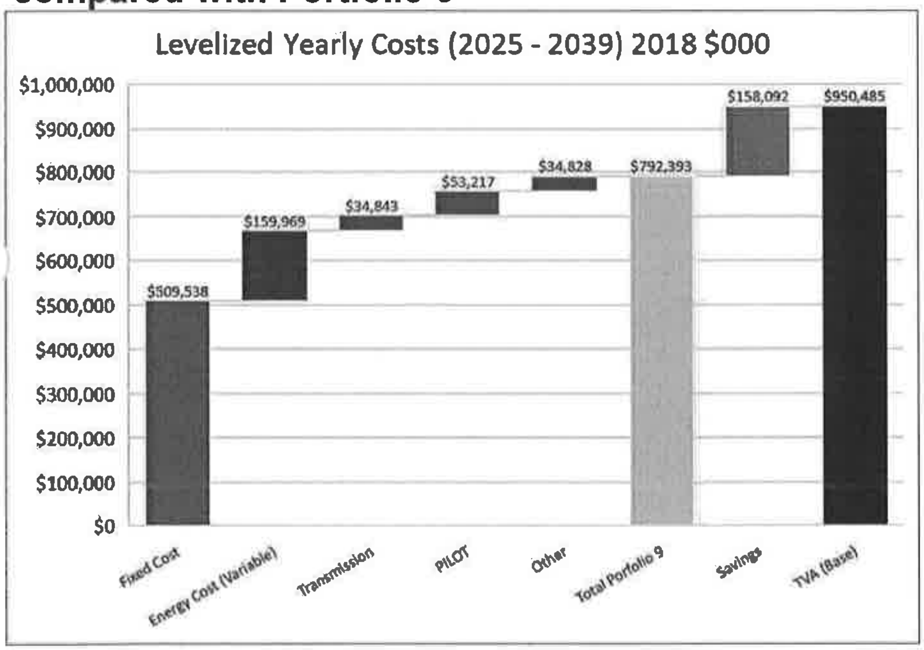


- Siemens forecast assumptions drives a future rate for TVA of about $71/MWh. If TVA rate were to be maintained at the current $75/MWh, the savings would increase by about $66 million in 2018 $.
- All savings are reported in real 2018 $. If future inflation is 2%/year, the actual average savings is about $200 million/year.

## Focusing on the period after notice is given, levelized costs (2025-2039) with TVA current contract compared with Portfolio 9

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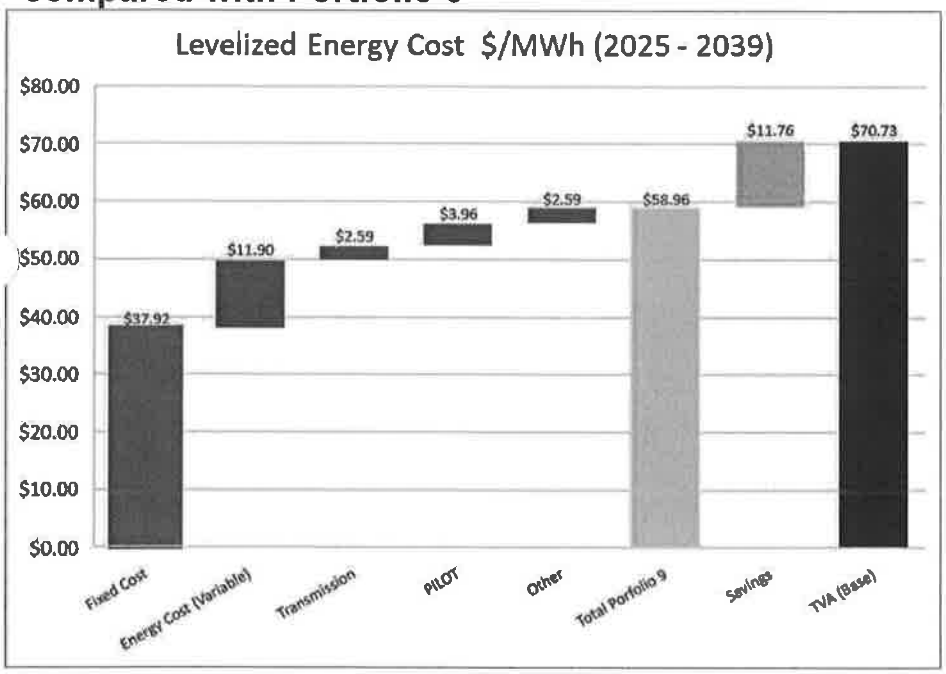


- This shows savings on a levelized cost of energy basis ($/MWh)

# Recommendations

## No Regret Actions if MLGW Joins MISO

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If MLGW chooses to exit the TVA contract and join MISO, MLGW should:

- Maximize the amount of local renewable generation, which provides local support and it is not affected by transmission. This is a no regret decision, i.e. it is present in all Portfolios and should be pursued.
- One combined cycle (450 MW) is present in all preferred solutions, thus this is a no regret decision. However, its size could be subject to further optimization.
- Installing at least two combustion turbines (237 MW) in 2025, also appears to be a no regret solution. Also, if two CCGTs are selected (as in Portfolio 6) and then two CTs would be required to reduce the risk of load shedding under N-1-1 to zero.
- MLGW should seek to become part of MISO Local Resource Zone 8 rather than becoming an independent zone. Both MLGW and the current members in LRZ8 stand to gain from this given the load diversity and the larger size of the new zone.

## Recommended Next Steps to Confirm Savings Before Making a Final Determination

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An RFP should be undertaken by MLGW to confirm the savings before making a final decision.

The IRP can be utilized to determine the general mix of assets and locations of interest in the RFP and the orders of magnitude of transmission required.

Differences between Portfolios 5, 9, 6 and 10 can be reassessed with bids provided by potential suppliers.

Options to manage fuel price risk should be an element to be included in the RFP

## No Regret Actions if MLGW Stays with TVA

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In case MLGW decides to stay with TVA:

- MLGW should explore options to increase the amount of local renewable generation (which is limited to 5% offered by TVA under the 20-year LTP).

- In addition, MLGW should assess further the LTP option. On one hand there will be a reduction on the costs and the 20-year NPVRR with the LTP is approximately $400 million lower than without it. On the other hand, MLGW will be locked for 20 years or more and unable to control or take advantage of development in the power industry as, for example, deeper drops in the cost of renewable generation and storage that could increase the economic savings for reconsidering exiting TVA and joining MISO at a later date. The value of the optionality provided by a shorter term exit can be evaluated.

- This analysis only needs to be performed if MLGW chooses to stay with TVA.

## Questions

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# Glossary

# Glossary

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- All-in Capital Cost = The capital costs for building a facility within the plant boundary, which includes equipment, installation labor, owners costs, allowance for funds used during construction, and interest during construction.
- Appalachia Basin = Marcellus Shale Play and Utica Shale Play.
- Average Demand = Average of the monthly demand in megawatts.
- Average Heat Rate = The amount of energy used by an electrical generator to generate one kilowatt hour (kWh) of electricity.
- Baseload Heat Rate = The amount of energy used by an electrical generator to generate one kilowatt hour (kWh) of electricity at baseload production. Baseload production is the production of a plant at an agreed level of standard environmental conditions.
- Breakeven Cost = Average price of gas required to cover capital spending (ideally adjusted to regional prices).
- BAU = Business As Usual
- BTU = British Thermal Unit = unit of energy used typically for fuels.
- CF = Capacity Factor. The output of a power generating asset divided by the maximum capacity of that asset over a period of time.
- CCGT (or CC) = Combined Cycle plant, gas turbine combined with an steam turbine
- CCS = Carbon Capture and Sequestration
- CT = Combustion Turbine
- DER = Distributed Energy Resources, distributed generation, small scale decentralized power generation or storage technologies
- DS = Distributed Solar
- Dth = Dekatherm (equal to one million British Thermal Units or 1 MMBtu)
- EE = Energy Efficiency
- ELCC = Effective Load Carrying Capability
- EFT = Enhanced Firm Transportation (varies by pipeline but can include short- or no-notice changes to day-ahead nominations of fuel delivery
- FID = Final Investment Decision
- FOM = Fixed operations and maintenance costs
- FT = Firm Transportation. FT capacity on a natural gas pipeline is available 24/7 and is more expensive than interruptible transportation (IT) capacity but unused FT capacity can be sold on secondary market.
- Futures = Highly standardized contract. Natural gas futures here are traded on the New York Mercantile Exchange (NYMEX) or Chicago Mercantile Exchange (CME).

## Glossary

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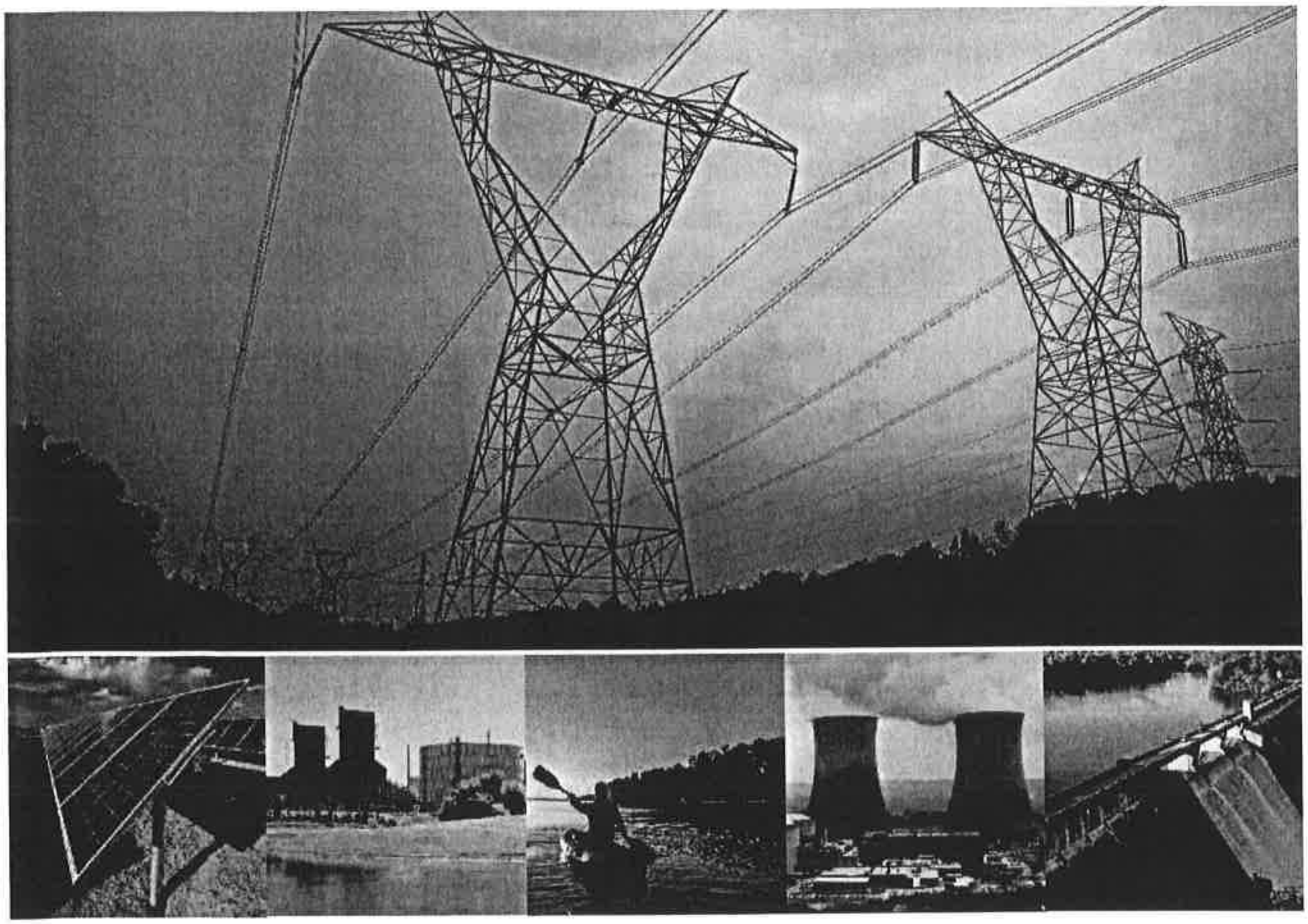
- GT = Gas Turbine
- IPP = Independent Power Producer
- IRP = Integrated Resource Plan
- LNG = Liquified natural gas
- LCOE = Levelized cost of energy
- LOLE = Loss of load expectation
- LOLH = Loss of load hours
- LTCE = Long Term Capacity Expansion Plan; optimization process to select generation
- MMBtu = million British Thermal Units, unit of energy usually used for fuels
- MWh = unit of energy usually electric power = 1 million watts x hour
- MW = unit of power = 1 million watts
- Peak Demand = The maximum demand in megawatts (MW) in a year
- PPA = Power Purchase Agreement; contract to purchase the power from a generating asset
- PV = Photovoltaic
- Reserve Margin = The amount of electric generating capacity divided by the peak demand.
- RPS = Renewable Portfolio Standard: a regulation that requires the increased production of energy from renewable energy sources
- RFP = Request for Proposal
- SMR = Small Modular Reactor
- "Sweet Spot" Core Acreage = Areas within a natural gas play that offer the highest production at least cost.
- Utility Scale = large grid-connected power generation, could be solar, gas, diesel, etc.
- VOM = Variable operations and maintenance costs
- Wheeling = a transaction by which a generator injects power onto a third party transmission system for delivery to a client (load).

# EXHIBIT 7

# 2019 Integrated Resource Plan

## VOLUME I - FINAL RESOURCE PLAN



TENNESSEE VALLEY AUTHORITY

**Tennessee Valley Authority**, 400 West Summit Hill Drive, Knoxville, Tennessee 37902

Message from the CEO

As the largest provider of public power in the nation, TVA provides low-cost, environmentally responsible and reliable power to the 10 million people of the Tennessee Valley region. We've been delivering our mission of service since 1933, all the while ensuring that our capabilities grow and change with the times.

This Integrated Resource Plan examines how TVA can meet future power demand in new and innovative ways. The Plan considers costs, environmental factors, reliability, regulations, energy efficiency, technological advancements, customer demands and other important factors to help us determine the best options for our energy future.

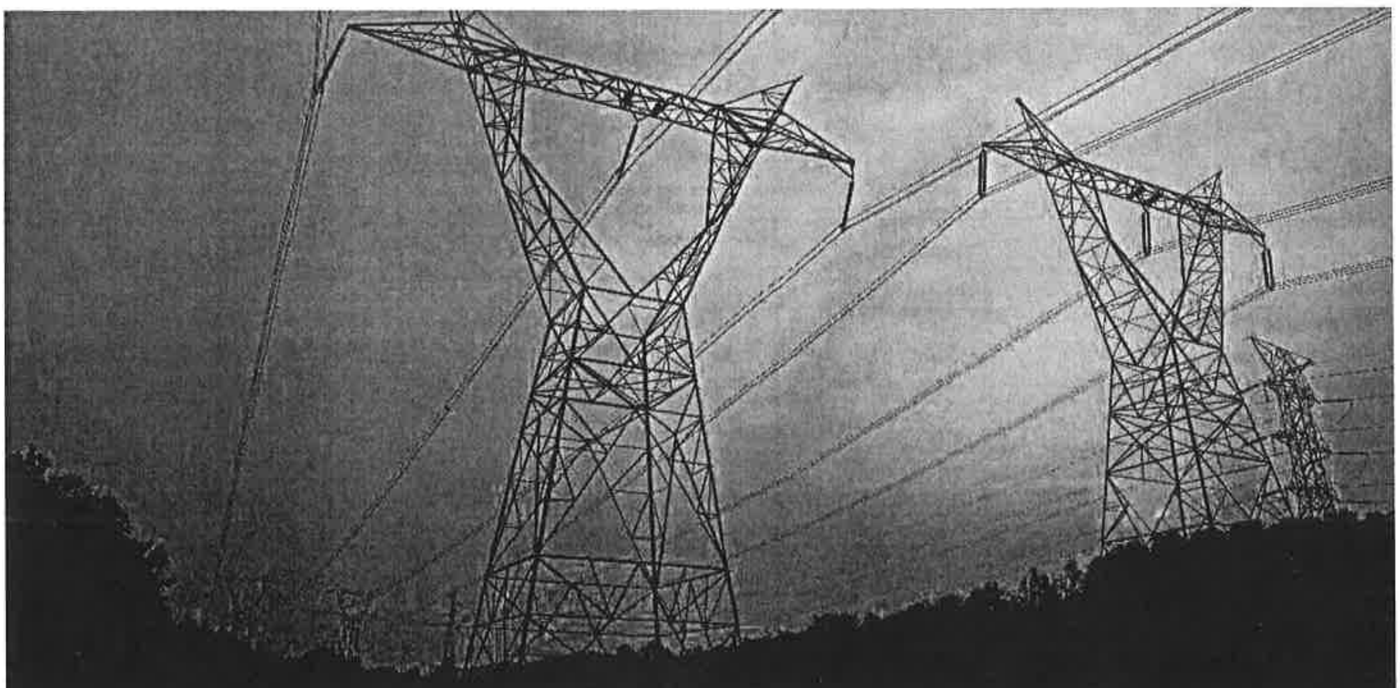
In developing the Plan, TVA enlisted the help of subject matter experts, our Regional Energy Resource Council and the public at large to ensure we considered the best possible options and the most likely future scenarios. TVA also relied on the diverse backgrounds and viewpoints of a working group of industry experts, environmental and business leaders, elected officials and others. This group helped TVA develop this Plan and its associated Environmental Impact Statement, which analyzes the potential impacts to the environment, economy and population of the Valley based on outputs of the Plan.

Collaborative planning efforts like this are an important part of how TVA partners with the people and communities we serve to improve quality of life in our region. In an ever-changing world, this Integrated Resource Plan will guide us on ways to live brighter lives together for decades to come.

Jeff Lyash

# 2019 Integrated Resource Plan

## EXECUTIVE SUMMARY



TVA

TENNESSEE VALLEY AUTHORITY

# Introduction

## PURPOSE AND NEED

The Tennessee Valley Authority's 2019 Integrated Resource Plan (IRP) is a long-term plan that provides direction on how TVA can best meet future demand for power. It shapes how TVA will provide low-cost, reliable and clean electricity; support environmental stewardship; and foster economic development in the Tennessee Valley for the next 20 years. The plan is a crucial element for TVA's success in a constantly changing business and regulatory environment, and it will better equip TVA to meet many of the challenges facing the electric utility industry in the coming years to benefit the Valley. The IRP will enhance TVA's ability to create a more flexible power-generation system that can successfully integrate increasing amounts of renewable energy sources and distributed energy resources (DER) while ensuring reliability. The IRP also will inform TVA's next Long-Range Financial Plan.

## TVA POWER SYSTEM

As the nation's largest public power provider, TVA delivers safe, reliable, clean, competitively priced electricity to 154 local power companies and 58 directly served customers. TVA's power portfolio is dynamic and adaptable in the face of changing demands and regulations. TVA's portfolio has evolved over the past decade to a more diverse, reliable and cleaner mix of generation resources, which today provides 54 percent carbon-free power. In Fiscal Year (FY) 2018, TVA efficiently delivered more than 163 billion kilowatt-hours of electricity to customers from a power supply that was 39 percent nuclear, 26 percent natural gas, 21 percent coal-fired, 10 percent hydro, and 3 percent wind and solar. The remaining one percent results from TVA programmatic energy efficiency efforts.

## SUMMARY OF IRP PROCESS AND GOALS

TVA used an integrated, least-cost framework that considered multiple views of the future to determine how potential power-generation resource portfolios could perform in different market and external conditions. We conducted the IRP process in a transparent, inclusive manner that provided numerous opportunities for public education and participation. Stakeholders and the public provided invaluable input that helped shape the IRP. The analysis performed in this IRP study relied on industry-standard models and incorporated best practices while using an innovative methodology to more fully evaluate the role of distributed energy resources as resources in our power supply. Resource cost and performance input data were independently validated. TVA's goal with the IRP was to identify an optimal energy resource plan that performs well under a variety of future conditions, taking into account cost, risk, environmental stewardship, operational flexibility and Valley economics. Per the National Environmental Policy Act (NEPA), TVA also prepared an Environmental Impact Statement (EIS) to analyze the 2019 IRP's potential impacts on the environment, economy and population in the Tennessee Valley.

# TVA's 2019 IRP Recommendation

## STUDY RESULTS

During the IRP process, TVA — with significant input from stakeholders and the public — considered a wide range of future scenarios, various business strategies and a diverse mix of power-generation resources to build on TVA's existing asset portfolio. IRP study results show:

- There is a need for new capacity in all scenarios to replace expiring or retiring capacity.
- Solar expansion plays a substantial role in all futures.
- Gas, storage and demand response additions provide reliability and/or flexibility.
- No baseload resources (designed to operate around the clock) are added, highlighting the need for operational flexibility in the resource portfolio.
- Additional coal retirements occur in certain futures.
- Energy efficiency (EE) levels depend on market depth and cost-competitiveness.
- Wind could play a role if it becomes cost-competitive.
- In all cases, TVA will continue to provide for economic growth in the Tennessee Valley.

## OBSERVATIONS

TVA has observed that the scenario, or future environment, it finds itself operating in will have more impact on overall results than the strategy or strategies it implements. TVA also recognizes that all strategies have positive aspects but also have unique tradeoffs to consider. If TVA needs to shift its resource mix, that need will be driven by these key variables: changing market conditions, more stringent regulations and technology advancements. Recognizing that a variety of future scenarios are possible and each strategy has positive aspects, all IRP results are included in the IRP Recommendation to provide flexibility for how the future evolves.

Over the next **20** years

Up to **14** GW solar additions (nameplate)

Up to **5** GW storage additions

All portfolios point to a TVA power system that will be LOW-COST, RELIABLE, and CLEAN

**2** to **17** GW Natural Gas Additions

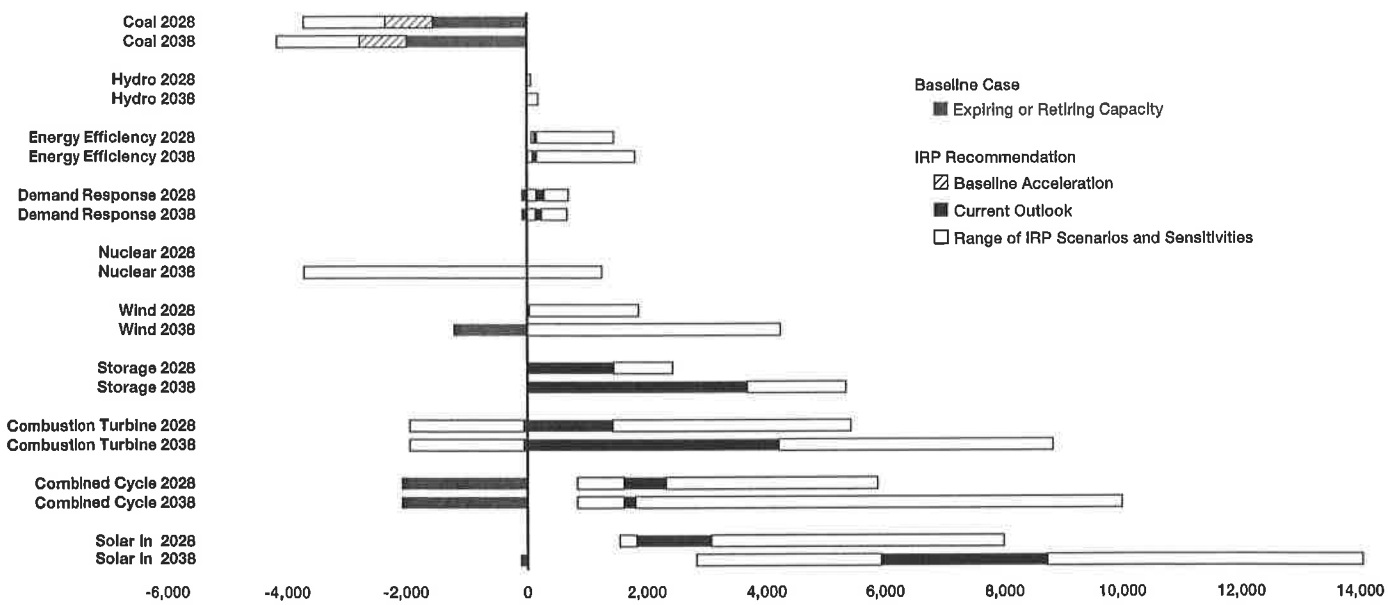
Evaluation of additional coal and gas retirements

Projected **70%** reduction in $CO_2$ Intensity

Average results from 2005 baseline (lbs/MWh)

# TVA's 2019 IRP Recommendation

**Range of MW Additions and Subtractions by 2028 and 2038**




**Notes**

- **MWs are incremental additions from 2019 forward. Board-approved coal retirements are excluded from the totals.**
- **Browns Ferry Nuclear Plant license is not extended in the No Nuclear Extensions Scenario (outside of TVA control).**
- **Upper bounds of potential natural gas and solar additions are driven by the Valley Load Growth Scenario.**
- **Solar and wind are shown in nameplate capacity; accelerated solar additions are reflected in the IRP Recommendation.**
- **Solar, gas, and storage ranges include utility-scale and distributed additions (where promoted in a strategy).**

# TVA's 2019 IRP Recommendation

TVA's recommended planning direction affirms its commitment to a diverse and flexible resource portfolio guided by the least-cost system planning mandate. The ranges shown, stated in megawatts (MW) of capacity, provide a general guideline for resource selections. In developing a Recommendation from the study, TVA elected to establish guideline ranges for key resource types (owned or contracted) that make up the target power supply mix. This general planning direction is expressed over the 20-year study period while also including more specific direction over the first 10-year period. Meeting the Valley's future needs in accordance with the resource technologies and ranges in this Recommendation will position TVA to continue to deliver low-cost, reliable and clean power to the people of the Tennessee Valley.

**Coal:** Continue with announced plans to retire Paradise in 2020 and Bull Run in 2023. Evaluate retirements of up to 2,200 MW of additional coal capacity if cost-effective.

**Hydro:** All portfolios reflect continued investment in the hydro fleet to maintain capacity. Consider additional hydro capacity where feasible.

**Energy Efficiency:** Achieve savings of up to 1,800 MW by 2028 and up to 2,200 MW by 2038. Work with our local power company partners to expand programs for low-income residents and refine program designs and delivery mechanisms with the goal of lowering total cost.

**Demand Response:** Add up to 500 MW of demand response by 2038 depending on availability and cost of the resource.

**Nuclear:** Pursue option for second license renewal of Browns Ferry for an additional 20 years. Continue to evaluate emerging nuclear technologies, including small modular reactors, (SMR) as part of technology innovation efforts.

**Wind:** Existing wind contracts expire in the early 2030s. Consider the addition of up to 1,800 MW of wind by 2028 and up to 4,200 MW by 2038 if cost-effective.

**Storage:** Add up to 2,400 MW of storage by 2028 and up to 5,300 MW by 2038. Additions may be a combination of utility and distributed scale. The trajectory and timing of additions will be highly dependent on the evolution of storage technologies.

**Gas Combustion Turbine:** Evaluate retirements of up to 2,000 MW of existing combustion turbines if cost-effective. Add up to 5,200 MW of combustion turbines by 2028 and up to 8,600 MW by 2038 if a high level of load growth materializes. Future CT needs are driven by demand for electricity, solar penetration, and evolution of other peaking technologies.

**Gas Combined Cycle:** Add between 800 and 5,700 MW of combined cycle by 2028 and up to 9,800 MW by 2038 if a high level of load growth materializes. Future CC needs are driven by demand for electricity and gas prices, as well as by solar penetration that tends to drive CT instead of CC additions.

**Solar:** Add between 1,500 and 8,000 MW of solar by 2028 and up to 14,000 MW by 2038 if a high level of load growth materializes. Additions may be a combination of utility and distributed scale. Future solar needs are driven by pricing, customer demand, and demand for electricity.

The IRP Recommendation meets the dual objective of ensuring flexibility to respond to the future while providing guidance on how our resource portfolio should change as the future unfolds.

# Implementation

## CONSIDERATIONS

With the implementation of the IRP Recommendation will come certain challenges. For example, the IRP Recommendation includes significant renewables expansion, which means it will become increasingly important to know the location of renewable resources, both utility and distributed scale, and how weather impacts solar generation. Early experience with battery storage on the system would provide additional insight to how the various storage-use cases might be employed to provide economic benefit and system flexibility, especially with increasing penetration of renewables. TVA will need to partner with local power companies and other stakeholders in the region to better understand the potential for distributed resources in the Valley and their locational value to inform resource decisions. Finally, the IRP Recommendation also includes more conventional resources, primarily gas-fired, and TVA will need to consider the implementation challenges in the areas of siting and permitting, both for the units themselves and associated transmission lines and gas pipelines.

In the process of developing the IRP, stakeholders raised a number of policy-related issues that are outside the scope of the IRP itself but will need to be considered as TVA moves toward implementation of recommendations from the IRP study. These considerations include continued evolution of programs that provide flexibility for customer-owned generation, evolution of federal/state energy and environmental policies, advancements in customer expectations and requirements for clean energy, and enhancing low-income equity and energy/environmental justice.

## NEAR-TERM ACTIONS

The scenarios and strategies evaluated in the IRP provide insights to how TVA's resource portfolio may need to evolve as the future becomes clearer. The results indicate there are near-term actions that would provide benefit across multiple futures. The actions include:

### RENEWABLES & FLEXIBILITY

- Add solar based on economics and to meet customer demand.
- Enhance system flexibility to integrate renewables and distributed resources.
- Evaluate demonstration battery storage to gain operational experience.

### EXISTING FLEET

- Pursue option for license renewal for TVA's nuclear fleet.
- Evaluate engineering end-of-life dates for aging fossil units to inform long-term planning.

### ENERGY USAGE

- Conduct market potential study for energy efficiency and demand response.
- Collaborate with states and local communities to address low-income energy efficiency.
- Collaboratively deploy initiatives to stimulate the local electric vehicle market.

### DISTRIBUTION PLANNING

- Support development of Distribution Resource Planning for integration into TVA's planning process.

### KEY SIGNPOSTS TO GUIDE DECISIONS IN THE LONGER TERM

As the future unfolds, TVA will monitor key signposts that will guide decisions in the longer term. The signposts relate to key variables that could have a significant influence on the future generation portfolio. These key signposts include:


TVA will closely monitor these key drivers related to changing market conditions, more stringent regulations, and technology advancements to inform appropriate actions within the recommended ranges and appropriate timing for initiating the next IRP.

# How TVA Developed the Integrated Resource Plan: An 18-Month Process

## OVERVIEW

Developing the 2019 IRP has been an approximately 18-month process that began in February 2018 and will conclude when a Record of Decision is released. The IRP process will have included the following activities:

- **Scoping,** which took place in winter/spring 2018 and identified issues important to the public and laid the foundation for developing the IRP.
- **Development of Model Input and Framework,** which occurred in spring/summer 2018 and included identifying and developing scenarios, resource options and business strategies to evaluate how a future portfolio might change under different conditions.
- **Analysis and Evaluation,** which took place in fall 2018 and included developing and evaluating the performance of the 30 resource portfolios.
- **Presentation of Initial Results,** which occurred in February 2019 with release of the draft IRP and EIS.
- **Public Comment Period,** which was held from February 15 to April 8, 2019.
- **Additional Analysis,** which was completed in response to stakeholder and public comments.
- **Completion of the Study**, which includes the IRP Recommendation, near-term actions and key signposts, and the final environmental assessment.
- **Publication of the Final IRP and EIS** on June 28, 2019, on TVA's website.
- **Expected Request for Approval** of the IRP Recommendation from the Board in August 2019.
- **Record of Decision** will be published after Board approval.

# Developing the IRP

## PLANNING APPROACH

### Uncertainties and Scenarios

With input from the IRP Working Group, TVA designed scenarios that are outside of TVA's control but represent possible futures in which TVA may find itself operating. TVA created a list of uncertainties that could alter the future operating environment and affect the cost of electricity and/or mix of optimal resources. The scenarios are:

| | SCENARIOS |
|---|---|
| 1 | **CURRENT OUTLOOK** which represents TVA's current forecast for these key uncertainties and reflects modest economic growth offset by increasing efficiencies; |
| 2 | **ECONOMIC DOWNTURN** which represents a prolonged stagnation in the economy, resulting in declining loads (customers using less power) and delayed expansion of new generation; |
| 3 | **VALLEY LOAD GROWTH** which represents economic growth driven by migration into the Valley and a technology-driven boost to productivity, underscored by increased electrification of industry and transportation; |
| 4 | **DECARBONIZATION** which is driven by a strong push to curb greenhouse gas emissions due to concern over climate change, resulting in high $CO_2$ emission penalties and incentives for non-emitting technologies; |
| 5 | **RAPID DER ADOPTION** which is driven by growing consumer awareness and preference for energy choice, coupled with rapid advances in technologies, resulting in high penetration of distributed generation, storage and energy management; |
| 6 | **NO NUCLEAR EXTENSIONS** which is driven by a regulatory challenge to relicense existing nuclear plants and construct new, large-scale nuclear. This scenario also assumes subsidies to drive small modular reactor (SMR) technology advancements and improved economics. |

### Strategies

With input from the IRP Working Group, TVA developed five strategies, which are business decisions or directions that TVA could employ in each scenario. As it relates to strategies in the IRP, the word "promote" means an incentive was modeled to make the resource more attractive for adoption or selection. The five strategies are:

| | STRATEGIES |
|---|---|
| A | **BASE CASE** which represents TVA's current assumptions for resource costs and applies a planning reserve margin constraint. This constraint applies in every strategy and represents the minimum amount of capacity required to ensure reliable power; |
| B | **PROMOTE DISTRIBUTED ENERGY RESOURCES** which incents DER to achieve higher, long-term penetration levels. The DER options include energy efficiency, demand response, combined heat and power, distributed solar and storage; |
| C | **PROMOTE RESILIENCY** which incents small, agile capacity to maximize operational flexibility and the ability to respond to short-term disruptions on the power system; |
| D | **PROMOTE EFFICIENT LOAD SHAPE** which incents targeted electrification (by incentivizing customers to increase electricity usage in off-peak hours) and demand response (by incentivizing customers to reduce electricity usage during peak hours). This strategy promotes efficient energy usage for all customers, including those with low income; |
| E | **PROMOTE RENEWABLES** which incents renewables at all scales (from utility size to residential) to meet growing or existing consumer demand for renewable energy. |

## MODELING ASSUMPTIONS AND CANDIDATE TECHNOLOGIES

TVA uses an industry standard model to derive an optimal capacity plan, considering the focus of each strategy evaluated in each scenario. Modeling assumptions, the framework of IRP planning, are the constraints and planning guidelines that are put into the model. The reliability constraint is especially critical, as it ensures we have enough capacity at all times to provide reliable electricity to customers. For the 2019 IRP, it also is crucial to understand how the system would operate with more renewables and DER on the system – driving a greater need for operational flexibility. TVA considered a broader range of mature and emerging technologies in this IRP, including some distributed energy technologies.

## STAKEHOLDER & PUBLIC INVOLVEMENT

Throughout the IRP process, TVA engaged external stakeholders to understand diverse opinions and to challenge assumptions. TVA established the IRP Working Group, whose 20 members represent diverse interests in the Valley. The IRP Working Group met approximately monthly to review input assumptions and preliminary results and to enable its members to provide their respective views to TVA. TVA also presented IRP progress updates to the Regional Energy Resource Council (RERC), a federal advisory committee that provides advice to the TVA Board of Directors on a range of energy-related matters, including the IRP.

During a 60-day scoping period from February 15 through April 16, 2018, TVA obtained public comments on the scope of the effort to develop this IRP, which helped shape the draft IRP and EIS. After the release of the draft IRP and EIS on February 15, 2019, TVA provided a public comment period through April 8, 2019. TVA held meetings across the Tennessee Valley and an online webinar, and accepted public comments via mail, email, online and in-person at the meetings. Input was critical in shaping the IRP and EIS, and many of the sensitivity analyses that were performed were informed by stakeholder and public input.

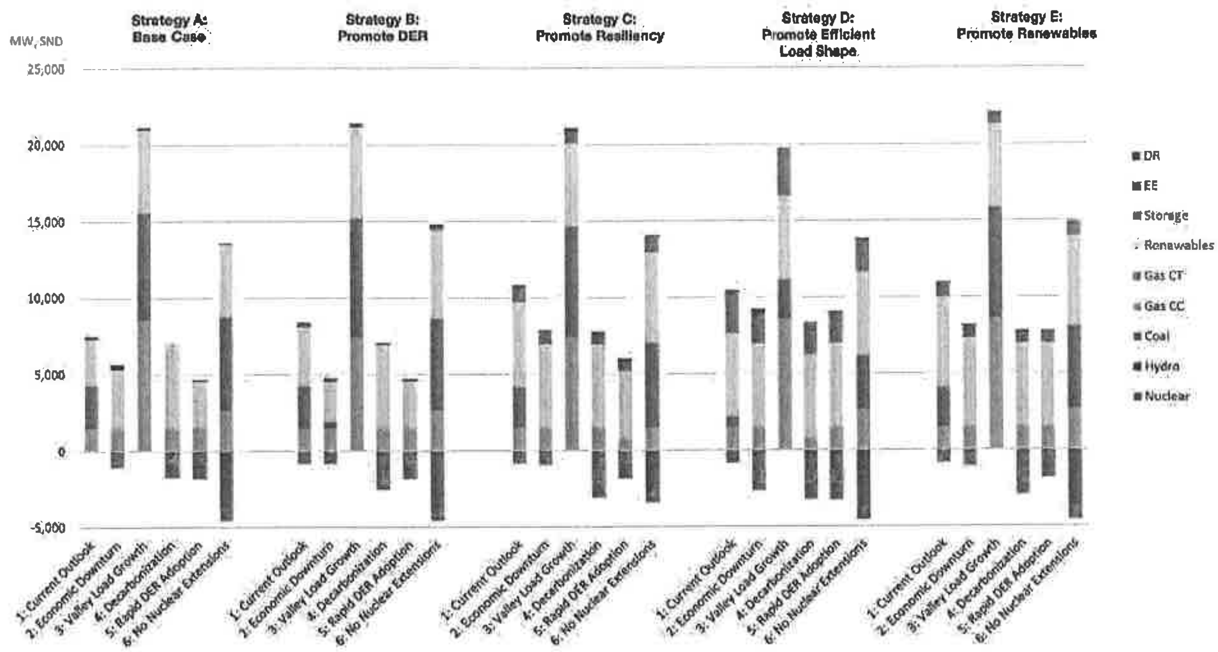
**The IRP Working Group included representatives from:**

- State and local governments
- Academia and research groups
- Advocacy groups
- Local power companies (LPCs)
- Economic development organizations
- Directly-served/ industrial customers

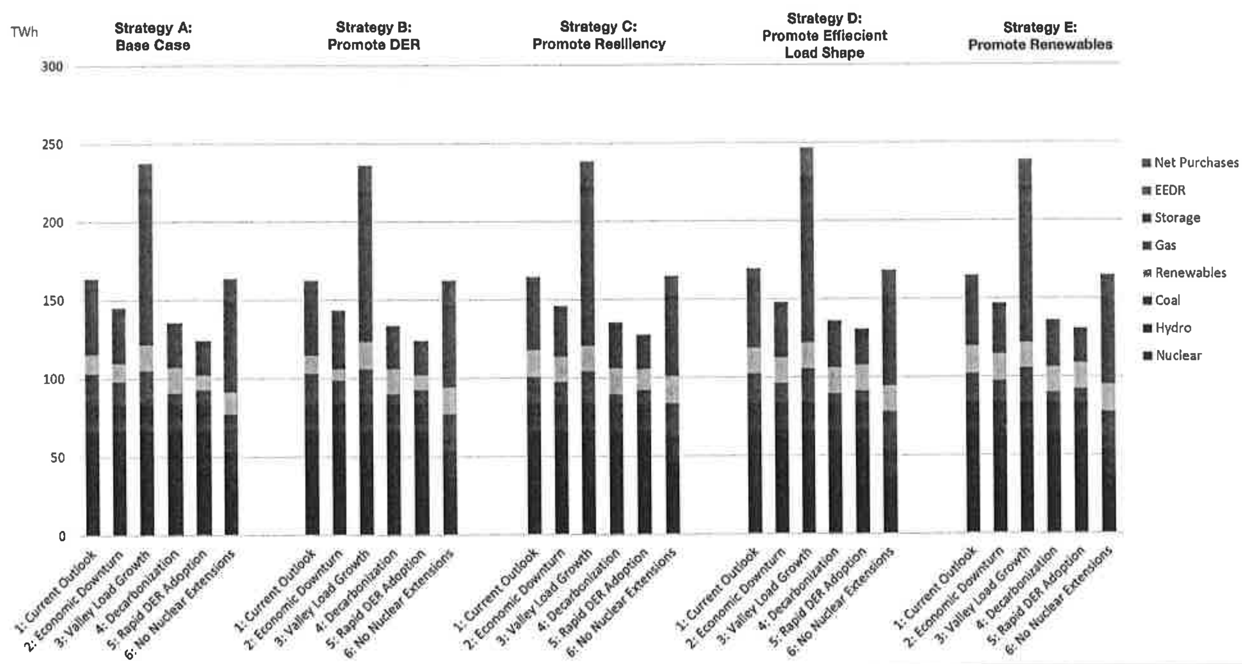
# Developing the IRP

## EVALUATING THE PORTFOLIOS

**Incremental capacity by 2038 consists of additions of new energy resources and retirement of existing energy resources for the portfolios associated with each strategy.**



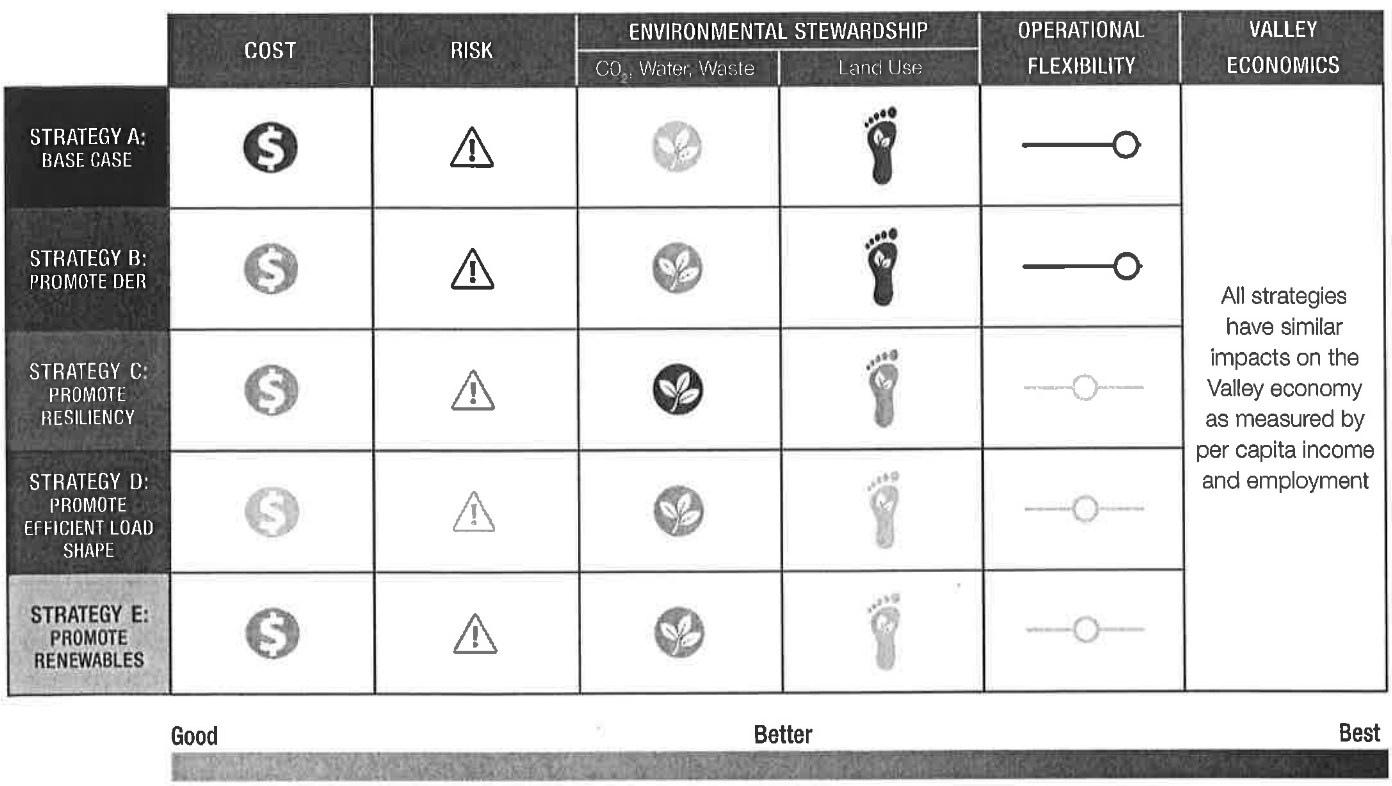

**Total Energy in 2038 by resource type in the portfolios associated with each strategy.**



## EVALUATING THE PORTFOLIOS

Each IRP case represents a combination of expectations about the future environment TVA operates in and potential strategies TVA could employ that result in unique resource portfolios. The modeling process resulted in 30 resource portfolios. The model analyzed how to achieve the lowest-cost portfolio with each strategy in each scenario, looking for the optimal solution within that particular combination. With input from the IRP Working Group and RERC, TVA identified 14 metrics that reflect desired goals and priorities in areas related to cost, risk, environmental stewardship, operational flexibility and Valley economics. The metrics were used to evaluate tradeoffs among the 30 resource portfolios.

**Strategy Performance**



# Developing the IRP

## SENSITIVITY ANALYSIS

When analyzing results from the draft IRP, TVA identified issues that warranted further evaluation prior to finalizing the study. In addition, TVA received helpful input from the IRP Working Group and the RERC, as well as from the public during the comment period. Many of the questions raised by TVA, stakeholders and the public focused on certain key assumptions that could influence results. To explore the impacts of changes in key assumptions and to inform the Recommendation, TVA evaluated sensitivities related to the following categories: natural gas prices; storage, wind, combined heat and power (CHP) and small modular reactor (SMR) capital costs; greater energy efficiency (EE) and demand response (DR) market depth; integration cost and flexibility benefit; pace and magnitude of solar additions; higher operating costs for coal plants; more stringent carbon constraints; and variation in climate.

**Summary of 2019 IRP Sensitivities**

| SENSITIVITY CASE Base Case comparison is the Current Outlook unless otherwise noted | CAPACITY EXPANSION IMPACTS BY 2038 GREEN indicates increase and RED indicated decrease in resource | | | | | | |
|---|---|---|---|---|---|---|---|
| | NUCLEAR | COAL | GAS | HYDRO | SOLAR | WIND | EEDR |
| Higher Natural Gas Prices | | | | +55 MW | +2,050 MW | | |
| Lower Natural Gas Prices | | | 2,000 MW CT replaced by CC | | -5,900 MW | | |
| Lower Wind Costs | | | -1,100 MW | | -3,100 MW | +4,200 MW | |
| Greater EE & DR Market Depth | | | -2,000 MW | | -2,200 MW | | +2,100 MW |
| Integration Cost & Flexibility Benefit | | | Minor timing differences | | Minor timing differences | | |
| Pace & Magnitude of Solar Additions | | | | | +1,100 MW | | |
| Magnitude of Solar Additions (Valley Load Growth) | | | 1,000 MW CC replaced by CT | | +6,000 MW | | |
| Higher Operating Costs for Coal Plants | | -2,200 MW | +1,500 MW | | | | |
| More Stringent Carbon Constraints (Decarbonization) | | -2,000 MW accelerated | CC expansion accelerated | +175 MW | | | |
| Variation in Climate | Summer derates | Summer derates | CT expansion accelerated | | +2,100 MW | | |

**Note**

- **Impacts shown in Summer Net Dependable MW, except for solar and wind that are shown in nameplate MW**

# The IRP and the Tennessee Valley Environment

## FORMING THE IRP RECOMMENDATION

The IRP results — including the 30 primary cases and the sensitivity cases — provide a robust set of potential resource additions and retirements. The final Recommendation is derived from this evaluation. The Recommendation takes into account customer priorities around power cost and reliability across different futures, along with environmental stewardship and Valley economics considerations. In developing a recommendation from the study, TVA elected to establish guideline ranges for key resource types (owned or contracted) that make up the target power supply mix. In order to distill the considerable number of cases evaluated through the original scenario and strategy analysis and the sensitivity cases, the Recommendation uses ranges that are centered on results obtained under the Current Outlook scenario. The other scenario and sensitivity results provide a sense of how the target power supply mix might change as the future changes. Recognizing that a variety of future scenarios are possible and each strategy has positive aspects, all IRP results are included in the Recommendation to provide flexibility for how the future evolves. Implementing the least-cost resource plan with all of these priorities in mind will help ensure TVA continues to fulfill its mission to serve the people of the Tennessee Valley.

## PURPOSE OF THE EIS

TVA's EIS assesses the natural, cultural and socioeconomic impacts associated with the 2019 IRP. The five strategies are the basis for the alternatives discussed in the EIS. The Base Case serves as the No-Action Alternative, and the remaining four strategies are the Action Alternatives. The draft EIS analyzed and identified the relationship of the natural and human environment to each of the five alternative strategies. The final EIS includes an additional alternative, the 2019 Recommendation (Target Power Supply Mix). The portfolios associated with each of the five alternative strategies, as well as the 2019 Recommendation, are quantitatively and qualitatively evaluated to determine the environmental impact. This evaluation addresses systemwide topics, including

- Greenhouse gas emissions
- Fuel consumption
- Air quality
- Water quality and quantity
- Waste generation and disposal
- Land requirements
- Socioeconomic impacts
- Environmental justice.

Public comments on the draft EIS and draft IRP are addressed in the final EIS.

The primary study area described in the EIS includes the combined TVA service area; the Tennessee River watershed; and parts of the Cumberland, Mississippi, Green and Ohio Rivers in TVA's power service area. For some resources, such as air quality and climate change, the assessment area extends beyond the TVA region. For some socioeconomic resources, the study area consists of the 170 counties where TVA is a major provider of electric power and/or operates generating facilities.

# The IRP and the Tennessee Valley Environment

## ENVIRONMENTAL IMPACTS OF THE 2019 IRP

Under all the portfolios and the 2019 Recommendation, there is a need for new capacity, with a significant expansion of solar generation overall. Uncertainty around future environmental standards for carbon dioxide emissions, along with the outlook for loads and gas prices, are key considerations when evaluating potential coal retirements. Emissions of air pollutants, the intensity of greenhouse gas emissions ($CO_2$ intensity) and generation of coal waste decrease under all strategies. Strategies focused on resiliency, load shape and renewables have the largest amounts of solar and storage expansion and coal retirements, resulting in lower environmental impact overall but higher land use. For most environmental resources, the impacts are greatest for the No Action alternative. The exception is the land area required for new generating facilities, which is greater for the action alternatives, particularly strategies which focus on resiliency, load shape and renewables. Most of this land area would be occupied by solar facilities, which, compared to most other energy resources, have a relatively low level of impact to the land. Additional sensitivity analysis showed the potential for an extended range of resource additions and retirements, which generally resulted in reduced impacts to most environmental resources. The land area occupied by solar facilities, however, could greatly increase.

# Conclusion

TVA finds considerable value in undertaking an IRP and EIS, and especially appreciates the input, review and insights of individuals on the IRP Working Group and the Regional Energy Resource Council. They spent considerable time helping TVA develop a robust plan that meets all the criteria outlined in its objectives. TVA values their involvement and the expertise they provided on behalf of their respective stakeholders in making this a better IRP.

As with any long-term plan, TVA's IRP reflects what we know today and can reasonably expect for the coming years. TVA and our employees across the Valley stand ready every day to carry out our three-part mission around energy, the environment and economic development. In an ever-changing world, TVA will do its best to continue to serve the people of the Tennessee Valley by providing low-cost, reliable and clean power in an environmentally responsible manner while promoting economic development across the Valley.

TVA

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## Appendices

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## List of Acronyms

| Acronym | Description |
|---|---|
| 4th NCA | Fourth National Climate Assessment |
| AC | Alternating Current |
| ACS | American Community Survey |
| APWR | Advanced Pressurized Water Reactor |
| ARC | Appalachian Regional Commission |
| B.P. | before present |
| BART | Best Available Retrofit Technology |
| BCF | billion cubic feet |
| Btu | British Thermal Units |
| CAA | Clean Air Act |
| CAES | compressed air energy storage |
| CAGR | compound annual growth rate |
| CC | Combined Cycle |
| CCR | Coal Combustion Residuals |
| CCS | carbon capture and storage/sequestration |
| CCW | condenser cooling water |
| CEQ | Council on Environmental Quality |
| CFR | Code of Federal Regulations |
| CHP | Combined Heat and Power |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| $CO_2$-eq | $CO_2$-equivalent emissions |
| CRM | Clinch River Mile |
| CT | Combustion Turbine |
| CWA | Clean Water Act |
| DC | Direct Current |
| DDT | Dichlorodiphenyltrichloroethane |
| DER | Distributed Energy Resources |
| DGIX | Distributed Generation Information Exchange |
| DO | dissolved oxygen |
| DOE | Department of Energy |
| DP | Data Profile |
| DR | demand response |
| DSM | Demand Side management |
| dV | deciview |
| E.O. | Executive Order |
| EA | Environmental Assessment |
| EBCI | Eastern Band of Cherokee Indians |
| EE | energy efficiency |

| Acronym | Description |
|---|---|
| EIS | Environmental Impact Statement |
| EPRI | Electric Power Research Institute |
| ERM | Emory River Mile |
| ESA | Endangered Species Act |
| FERC | Federal Energy Regulatory Commission |
| FGD | flue gas desulphurization |
| FOM | Fixed operating and maintenance costs |
| FY | Fiscal Year |
| gal/d/mi$^2$ | gallons per day per square mile |
| GDP | Gross Domestic Product |
| GHG | greenhouse gas |
| GP | Generation Partners |
| GPP | Green Power Providers |
| GW | gigawatt |
| GWh | gigawatt hours |
| HAP | Hazardous Air Pollutants |
| HFC | hydroflurocarbons |
| Hg | Mercury |
| HUC | Hydrologic Unit Code |
| HVAC | heating, ventilation, and air conditioning |
| HVDC | high voltage direct current |
| IGCC | integrated gasification combined cycle |
| IMP | Internal Monitoring Point |
| IPP | Independent power producers |
| IRP | Integrated Resource Plan |
| KDFWR | Kentucky Department of Fish and Wildlife Resources |
| KPDES | Kentucky Pollutant Discharge Elimination System |
| kV | kilovolt |
| KWh | kilowatt-hours |
| LCA | life cycle assessments |
| LED | light emitting diode |
| LPC | Local Power Companies |
| MAPE | Mean absolute percent error |
| MATs | Mercury and Air Toxics Standards |
| MBCI | Mississippi Band of Choctaw Indians |
| MBTA | Migratory Bird Treaty Act |
| MBtu | Million British Thermal Units |
| MGD | million gallons per day |
| MISO | Midcontinent Independent System Operator |
| MLGW | Memphis Light, Gas and Water |
| MSAs | metropolitan statistical areas |
| MW | Megawatt |

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| Acronym | Description |
|---|---|
| MWh | Megawatt-hour |
| N2O | Nitrous oxide |
| NAAQS | National Ambient Air Quality Standards |
| NEPA | National Environmental Policy Act |
| NFIP | National Flood Insurance Program |
| NHPA | National Historic Preservation Act |
| $NO_2$ | nitrogen dioxide |
| NOI | Notice of Intent |
| NPDES | National Pollutant Discharge Elimination System |
| NPS | National Park Service |
| NRC | Nuclear Regulatory Commission |
| NREL | National Renewable Energy Laboratory |
| NRHP | National Register of Historic Places |
| NWS | National Weather Service |
| ORSANCO | Ohio River Valley Water Sanitation Commission |
| PCB | polychlorinated biphenyl |
| PEP | Population Estimates Program |
| PFC | perfluorocarbons |
| PFOS | Perfluorooctane sulfonate |
| PM | particulate matter |
| PPA | Power Purchase Agreement |
| ppm | parts per million |
| PSA | Power Service Area |
| PURPA | Public Utility Regulatory Policies Act |
| PV | photovoltaic |
| PVRR | Present Value of Revenue Requirement |
| PWR | Pressurized Water Reactor |
| QCN | Quality Contractor Network |
| RBI | Reservoir Benthic Index |
| RCP | representative concentration pathway |
| RCRA | Resource Conservation and Recovery Act |
| REC | Renewable Energy Certificate |
| RFAI | Reservoir Fish Assemblage Index |
| RICE | reciprocating internal combustion engines |
| ROD | Record of Decision |
| ROS | Reservoir Operations Study |
| RSO | Renewable Standard Offer |
| SAE | Statistically Adjusted End-use model |
| SCPC | supercritical pulverized coal |
| SCR | selective catalytic reduction |
| SDTSA | state-designated tribal statistical areas |
| SEPA | Southeastern Power Administration |

| Acronym | Description |
|---|---|
| SLR | Second License Renewal |
| SMR | small modular reactors |
| SND | summer net dependable |
| $SO_2$ | sulfur dioxide |
| SOC | Special Opportunities Counties |
| SPCP | supercritical pulverized coal plant |
| SPP | Southwest Power Pool |
| T&D | transmission and distribution |
| TCP | Traditional Cultural Properties |
| TDEC | Tennessee Department of Environment and Conservation |
| TDS | total dissolved solids |
| TRM | Tennessee River Mile |
| TSCA | Toxic Substances Control Act |
| TSS | total suspended solids |
| TVA | Tennessee Valley Authority |
| TWRA | Tennessee Wildlife Resources Agency |
| USACE | U.S. Army Corps of Engineers |
| USBEA | U.S. Bureau of Economic Analysis |
| USBLS | U.S. Bureau of Labor Statistics |
| USCB | U.S. Census Bureau |
| USDA | U.S. Department of Agriculture |
| USDOE | U.S. Department of Energy |
| USET | United South and Eastern Tribes, Inc. |
| USFWS | U.S. Fish and Wildlife Service |
| USGS | U.S. Geological Survey |
| VOC | volatile organic compounds |
| VOM | Variable operating and maintenance costs |
| WAP | Weatherization Assistance Program |
| WKWMA | Western Kentucky Wildlife Management Area |

# 1 Introduction

TVA has developed the 2019 IRP and associated programmatic EIS to address the demand for power in the TVA service area, the resource options available for meeting that demand, and the potential environmental, economic and operating impacts of these options. The IRP will serve as a roadmap for meeting the energy needs of TVA's customers over the next 20 years.

## 1.1 TVA Overview

### 1.1.1 TVA's Mission

TVA was created by Congress in 1933 and charged with a unique mission – to improve the quality of life in the Valley through the integrated management of the region's resources. For more than eight decades, TVA has worked to carry out that mission and to make life better for the nearly 10 million people who live, work and play in the Valley. TVA is fully self-financed, funding virtually all operations through electricity sales and power system bond financing. TVA sets rates as low as feasible and reinvests net income from power sales into power system improvements and economic development initiatives. TVA makes no profit and receives no tax money. To achieve its overall mission of providing low-cost, reliable power to the people of the Valley, TVA focuses on four strategic imperatives: balancing power rates and debt so that TVA maintains low rates while living within its means; and recognizing the trade-off between optimizing the value of our asset portfolio and being responsible stewards of the Valley's environment and natural resources (Figure 1-1). Today, TVA continues to serve the people of the Tennessee Valley through its work in three areas: Energy, the Environment and Economic Development.


**Figure 1-1: Strategic Imperatives**

#### 1.1.1.1 Energy

TVA is the largest producer of public power in the United States. TVA provides wholesale power to 154 local power companies and directly sells power to 58 industrial and federal customers. TVA's power system serves nearly 10 million people in a seven-state, 80,000-square-mile region (the Valley).

TVA's generating assets include: six coal plants, three nuclear plants, 29 conventional hydro plants, one pumped storage hydro plant, nine natural gas combustion turbine (CT) gas plants, eight natural gas combined cycle (CC) gas plants, one diesel generator site, and 14 solar sites. TVA has gas-co-firing potential at one coal-fired site as well as biomass co-firing potential at all of its coal-fired sites. In total, these assets constitute a portfolio of 33,500 MWs. TVA also purchases a portion of its power supply from third-party operators under long-term power purchase agreements (PPAs).

Safe, clean, reliable and affordable electricity powers the economy of our region and enables greater prosperity and a higher quality of life for everyone. In setting rates, the TVA Board is charged by Section 113 of the Energy Policy Act of 1992 (now the least-cost, system-wide planning provision of the TVA Act) to have due regard for the primary objectives of the TVA Act, including the objective that power be sold at rates as low as are feasible.

TVA operates one of the largest transmission systems in the U.S. It serves an area of 80,000 square miles through a network of about 16,200 miles of transmission lines, 500 substations, switchyards and switching stations, and over 1,300 individual customer connection points. The system connects to switchyards at generating facilities and transmits power from them at primarily either 161 kV or 500 kV to local power companies and directly served customers. For the past 18 years, the system has achieved 99.999 percent power reliability. It efficiently delivered nearly 163 billion kilowatt-hours of electricity to customers in FY 2018.

Also, the TVA transmission system has 69 interconnections with 13 neighboring utilities at interconnection voltages ranging from 69-kV to 500-kV. These interconnections allow TVA and its neighboring utilities to buy and sell power from each other and to wheel power through their systems to other utilities. To the extent that Federal law requires access to the TVA transmission system, the TVA transmission organization offers services to others to transmit power at wholesale in a manner that is comparable to TVA's own use of the transmission system, according to FERC Standards of Conduct for Transmission Providers (FERC 2008).

In recent years, TVA has built an average of 75 miles of new transmission lines and several new substations and switching stations per year to serve new customer connection points and/or to increase the capacity and reliability of the transmission system. TVA has also upgraded many existing transmission lines. A major focus of recent transmission system upgrades has been to maintain reliability when coal units are retired. Between 2011 and 2018, TVA spent about $420 million on these upgrades and anticipates spending $10 million on coal-retirement related transmission system upgrades in 2019 and 2020. The upgrades include modifications of existing lines and substations and new installations as necessary to provide adequate transmission capacity, maintain voltage support, and ensure generating plant and transmission system stability. In May 2017, TVA began a $300 million, multi-year effort to upgrade and expand its fiber-optic network to help meet the power system's growing need for bandwidth as well as accommodate the integration of new distributed energy resources.

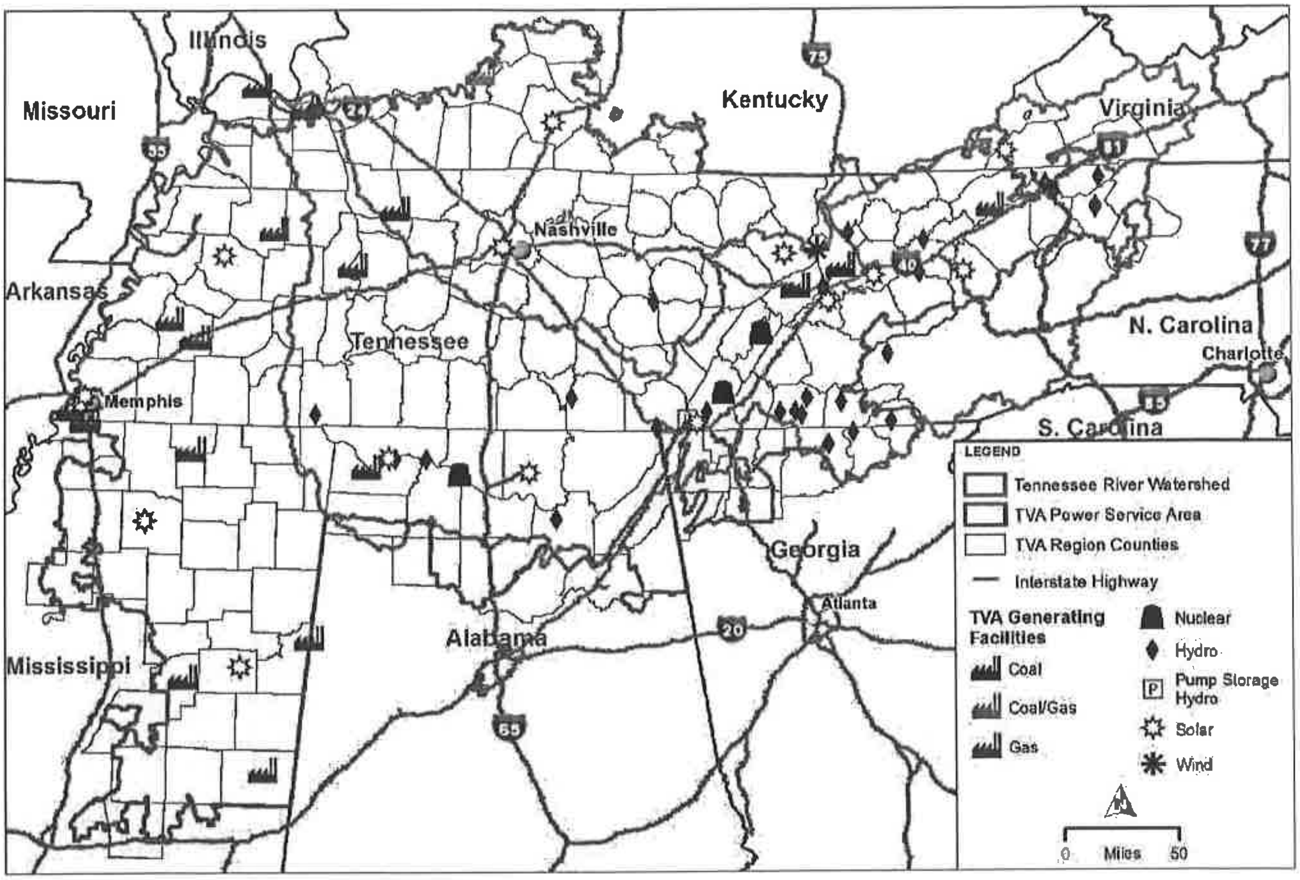


**Figure 1-2: Power Service Area and Tennessee River Watershed, herein the TVA region**

Additionally, TVA makes annual investments in science and technology innovation that enable TVA to meet future business and operational challenges. Core research activities directly support improving generation and delivery assets, enhancing air and water quality, and integrating clean energy resources.

### 1.1.1.2 Environmental Stewardship

Environmental stewardship is an important part of TVA's mission of service. TVA is committed to protecting the Valley's natural resources, as well as its historical and cultural heritage. TVA manages and monitors 293,000 acres of reservoir land, 11,000 miles of shoreline and 80 public recreation areas. These areas generate about $12 billion a year in recreation to the regional economy and create or retain about 130,000 jobs each year.

To protect water quality and aquatic life, TVA has installed equipment to add oxygen to the water around TVA dams and committed to releasing minimum flow to keep the downstream riverbed from drying out when power generation is shut off.

To protect air quality, TVA has invested nearly $7 billion installing systems to reduce nitrogen oxides and sulfur dioxide emissions from coal-fired plants. TVA has also reduced carbon dioxide emissions by retiring several of its oldest, least efficient coal-fired units and adding cleaner forms of power generation, including:

- the first nuclear unit of the 21st century,
- more clean-burning natural gas units,
- generating and purchasing more renewable energy.

Through FY 2018, these actions have helped TVA to achieve:

- a 98 percent reduction in sulfur dioxide ($SO_2$) from peak levels in 1977,
- a 94 percent reduction in nitrogen oxides ($NO_x$) emissions from peak levels in 1995,
- reduced water use, wastewater discharges, and waste production from TVA's operations, and
- a 47 percent reduction in carbon dioxide ($CO_2$) emissions through calendar year 2017 compared to 2005 levels.

#### 1.1.1.3 Economic Development

Economic development is a cornerstone of TVA's mission to make life better for Valley residents. In 2018, TVA worked in partnership with communities and the business sector to spur over $11.3 billion in business investments in the Valley, helping to attract and retain more than 65,400 jobs. This was in addition to assisting more than 200 companies to locate or expand existing operations in the Valley. TVA also assisted communities directly with more than 1,100 outreach activities related to economic growth preparedness and retail business development, including 34 communities in the Valley Sustainable Communities Program, which helps to differentiate those communities by highlighting and increasing local sustainability efforts. TVA is also providing ongoing economic development assistance to communities and companies through financial support, technical services, leadership training, market research and other business offerings.

## 1.2 Integrated Resource Planning

The purpose of the IRP and EIS process is to evaluate TVA's current energy resource portfolio and alternative future portfolios of energy resource options to meet the future electrical energy needs of the TVA region at a least system-wide cost while taking into account TVA's mission of energy, environmental stewardship and economic development. The Recommended Target Power Supply Mix described in the 2015 IRP was formally approved by the TVA Board of Directors in August 2015 and has guided TVA decisions since then.

Several recent industry-wide changes have led TVA to begin development of the new IRP and associated EIS ahead of the five-year cycle identified in the 2015 IRP.

Natural gas supplies are abundant and are projected to remain available at lower cost. The electric system load is expected to be flat, or even declining slightly, over the next 10 years. The price of renewable resources, particularly solar, continues to decline. Consumer demand for renewable and distributed energy resources (including distributed generation, storage, demand response and energy services, and energy efficiency programs) is growing. Given these recent changes, the main focus areas of the 2019 IRP are:

- System flexibility,
- Distributed energy resources, and
- Portfolio diversity.

> The focus on flexibility in this IRP is multi-faceted. The Valley benefits from a diverse power system that provides flexibility for how the future evolves. As the economics of renewables and distributed energy resources continue to improve, operational flexibility will be increasingly important to successfully integrate these resources into the generation portfolio. Due to their intermittent nature, TVA needs flexible resources that can quickly respond to dynamic loads.

### 1.2.1 IRP Objectives

The following objectives guide the development of this IRP:

- Deliver a plan aligned to mandated least-cost planning principles,
- Ensure the portfolio delivers energy in a reliable manner,
- Manage risk by utilizing a diverse portfolio of supply and demand-side resources,
- Deliver cleaner energy and continue to reduce environmental impacts,
- Evaluate increased use of renewables, energy efficiency, and distributed energy resources,
- Continue to innovate by dynamically modeling energy efficiency and distributed energy resources in the study,

- Proactively plan to meet future needs for system flexibility,
- Provide flexibility to adapt to changing market conditions and identify significant signposts,
- Increase credibility and trust through a collaborative and transparent process, and
- Integrate stakeholder perspectives throughout the study.

Given these objectives and in consideration of the focus areas listed above, the final, optimal resource plan has been developed with the goals of being low-cost, risk-informed, environmentally responsible, reliable, diverse, and flexible.

### 1.2.2 IRP Development

TVA developed this new IRP and associated EIS to proactively address several changes within the utility marketplace, both regionally and nationally. Upon adoption by the TVA Board, the IRP will replace the 2015 IRP. The purpose of the IRP and EIS processes is to evaluate TVA's current energy resource portfolio and alternative future portfolios of energy resource options to meet the energy needs of the Valley while taking into account TVA's mission of energy, environmental stewardship and economic development.

To ensure TVA best meets projected future needs, TVA has continued its tradition of incorporating innovations in each succeeding IRP.

- The 2011 IRP focused on diversifying and modernizing its generation portfolio, part of which included adding cost-effective renewables.
- The 2015 IRP identified distributed energy resources (DER) as a growing trend in the utility industry and designed a mechanism where energy efficiency could be chosen as a resource.
- The 2019 IRP:
    - Improves TVA's understanding of the impact and benefit of system flexibility to meet dynamically changing loads with increasing renewable and distributed resources.
    - Explores various DER scenarios, considering the speed and amount of DER penetration.
    - Determines the implications of implementing the selected diverse portfolio mix over the next 20 years.

Distributed energy resources (DER) are power generation and storage systems that are connected to the power distribution system and deliver power to the grid or that are "behind the meter" and deliver power directly to an end-user. Examples include solar panels, combined heat and power systems, microturbines, and battery storage systems. DER also includes energy management, such as energy efficiency and demand response.

### 1.2.3 IRP Innovations

Building upon previous versions of the IRP, the 2019 IRP includes modeling refinements, updated studies, and additional public outreach. The purpose of these innovations is to provide an IRP that evolves with the industry and helps TVA continue to provide reliable, clean power at the lowest feasible rate.

#### 1.2.3.1 Reserve Margin

TVA's planning reserve margin, which provides reserve capacity for unplanned events, has historically been an annual target based on a study focused on the summer peak. In the 2015 IRP, TVA's planning reserve margin was 15 percent applied across the year. TVA has a dual-peaking system, with similarly high demand in both winter and summer. In winter, there is increased thermal and hydro generating capacity but also greater weather-driven peak variability than in the summer. While solar capacity additions are expected, driven by increasing consumer demand and decreasing prices, solar generation does not coincide with winter peak demand times. Since the 2015 IRP, TVA conducted an updated reserve margin study to evaluate seasonal differences in demand and supply and the impact of increasing solar capacity on the system. The objective was to identify discrete reserve margin targets for summer and winter to ensure an industry best-practice level of reliability across both peak seasons. The study also evaluated the cost of reserves and reliability events to the customer. Based on the study, the planning reserve margins being applied in the 2019 IRP are 17 percent for the summer peak season and 25 percent for the winter peak season.

#### 1.2.3.2 Integration Cost and Flexibility Benefit

With increasing penetration of variable energy resources, such as wind farms, utility-scale solar farms and rooftop solar, utilities need to ensure their bulk system is flexible enough to respond to dynamically changing loads, even to load changes within each hour. If variable energy resources are added, the balance of the system must respond to their variability, driving an integration cost. Conversely, if very flexible assets (i.e., those that can rapidly change their output) are added, there is a benefit resulting from the balance of the system running more efficiently. To capture these impacts in long-term planning, TVA recently conducted a study to quantify an integration cost for solar and wind resources and a flexibility benefit for small, agile gas and storage resources. The result is a sub-hourly integration cost or flexibility benefit that was applied to energy or build costs in 2019 IRP modeling performed at an hourly level.

#### 1.2.3.3 DER Modeling

In the 2015 IRP, DER was included in the load forecast as a load modifier that reduced demand for electricity from TVA, and energy efficiency and demand response were modeled as selectable resources. In the 2019 IRP, TVA made further refinements in modeling behind-the-meter generation in the load forecast, including variations across the scenarios. We also modeled distributed generation resources, including combined heat and power, and distributed solar and storage. There are targeted levels of adoption of these distributed resources based on incentive levels in each strategy.

#### 1.2.3.4 Public Outreach and Engagement

Building upon the outreach and engagement work done for the 2015 IRP, TVA developed an outreach strategy to foster broader engagement from different demographic groups; a social media campaign designed to engage various audiences; and ongoing communications about the IRP, rather than communications only at key milestones.

Social media communications included multiple posts targeted to the different demographic groups on platforms such as Twitter, LinkedIn, Facebook and Instagram. Additionally, TVA published videos to build the public's knowledge and understanding of the electrical system as well as the IRP process. Additional details on social media outreach are located in Section 3.3.1 of Volume I.

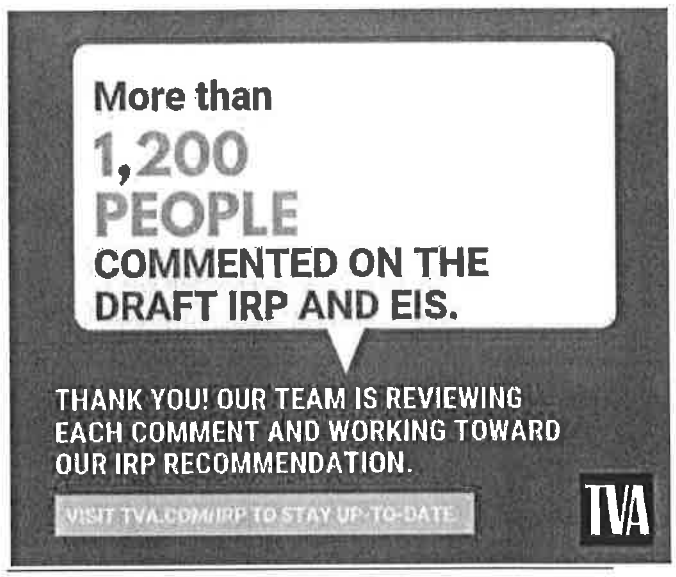


**Figure 1-3: Example of TVA IRP LinkedIn Post**

In conjunction with the issuance of the draft IRP and EIS documents for public review, TVA developed an interactive report to enable members of the public to learn about and provide comments on the draft IRP and EIS documents. Materials from public meetings that TVA hosted across the Valley are also on TVA's IRP webpage. The interactive report has been updated to capture final results.

## 1.3 Overview of Volumes I and II

Volume I contains the 2019 IRP along with descriptions on the methodology and development of the recommendation. This works in conjunction with Volume II, which contains the EIS. The EIS is an assessment conducted under the National Environmental Policy Act (NEPA) that describes the environmental effects of a proposed action and its alternatives that may have a significant effect on the quality of the human environment.

TVA developed the draft IRP and EIS and made them available to the public and government agencies for review and comment from February 15th, 2019, until April 8th, 2019. During the public comment period, TVA conducted public meetings across the Valley to discuss the IRP process, share draft results, and receive comments on the draft IRP and EIS. Over 1,200 people commented on the draft IRP and EIS. TVA considered all comments received, made revisions as appropriate, and is now publishing the final IRP and EIS. The final EIS includes TVA's responses to public comments on the Draft IRP and EIS.

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# 2 IRP Process

TVA's 2019 IRP process consisted of seven distinct steps:

1. Scoping
2. Develop Study Inputs and Framework
3. Analyze and Evaluate
4. Present Initial Results and Gather Feedback
5. Incorporate Feedback and Perform Additional Modeling
6. Identify Preferred Target Supply Mix
7. Approval of IRP Recommendations by TVA Board of Directors

Public participation was integral to the process and is explained in more detail in Chapter 3. Steps 2 through 6 are explained in more detail in Chapter 6.

## 2.1 Scoping

The IRP team collected information from TVA's resource planning, forecasting, and electricity generation experts to begin developing IRP model inputs. A 60-day public scoping period for TVA's 2019 IRP occurred from February 15 to April 16, 2018. The objective in this initial step was to identify resource options, strategies and future conditions that merited evaluation in the IRP process. Public scoping comments covered a wide range of issues, including the nature of the integrated resource planning process, preferences for various types of power generation, input on planning scenarios and strategies, and the environmental impacts of TVA's power generation. The comments received helped to identify issues important to the public and to lay the foundation for the EIS that supports the 2019 IRP. Additional information on the scoping process and results can be found in Volume I, Section 3.1.

## 2.2 Develop Study Inputs and Framework

When developing a long-term plan for a power system, utilities typically use a least-cost decision making framework that focuses on a single view of the future. TVA also uses a least-cost decision making framework but considers multiple views of the future to determine how potential resource portfolios could perform across multiple futures given different market and external conditions.

TVA's goal is to identify an energy resource plan that performs well under a variety of future conditions (e.g., a strong economy or a weak economy), thereby reducing the risk that a selected strategy or plan would perform well under one set of future conditions, but poorly under a different set of conditions. This increases the likelihood that TVA's plan will provide least-cost solutions to future demands for electricity from its power system regardless of how the future plays out.

This decision-making framework requires use of a scenario planning approach. Scenario planning provides an understanding of how the results of near-term and future decisions would change under different conditions over a 20-year planning horizon.

After review of the scoping comments, suggestions from members of the IRP Working Group (see Volume I, Section 3.2), and further analysis, TVA selected the five unique scenarios summarized in Table 2-1. In addition to these five scenarios, TVA also analyzed an additional Current Outlook scenario based on TVA's current assumptions about future conditions.

Scenarios are alternate plausible futures outside of TVA's control with different economic and regulatory conditions, as well as social trends and pace of adoption of newer technologies. Strategies are alternate business approaches within TVA's control that differ in the type and amount of resources that are promoted in the future. A portfolio is the result of a strategy evaluated inside a scenario. Each strategy and scenario combination will result in a 20-year resource portfolio to meet the energy needs of the Valley.

**Table 2-1: Description of the Six Scenarios**

| Scenario | Description |
|---|---|
| 1- The Current Outlook | TVA's current forecast for key uncertainties that reflects modest economic growth offset by impact of increasing efficiencies resulting in a flat load outlook |
| 2- Economic Downturn | Represents a prolonged stagnation in the economy, resulting in declining loads and delayed expansion of new generation |
| 3- Valley Load Growth | Represents economic growth driven by migration into the Valley, a technology-driven boost to productivity, and increased electrification of transportation |
| 4- Decarbonization | Represents a strong push to curb GHG emissions due to concern over climate change, resulting in high $CO_2$ emission penalties and incentives for non-emitting technologies |
| 5- Rapid DER Adoption | Represents growing consumer awareness and preference for energy choice, coupled with rapid advances in technologies driving high penetration of distributed generation, storage, and energy management |
| 6- No Nuclear Extensions | Represents a regulatory challenge to relicensing of existing and construction of new, large scale nuclear and a preference for more secure, modular, and flexible technologies, including subsidies to drive a breakthrough in Small Modular Reactor design and cost |

After review of the scoping comments, suggestions from members of the IRP Working Group, and further analysis, TVA selected five distinct strategies, including a base case representing least-cost planning with no specific resources promoted and reflecting decisions made to date by the TVA Board of Directors. The resource strategies TVA evaluated are shown in Table 2-2. These strategies differ in their emphasis on distributed generation, energy efficiency and demand response efforts, renewable energy resources, nuclear generating capacity additions, and coal-fired generation. The alternative strategies were analyzed in the context of six different scenarios (Table 2-1) that described plausible future economic and regulatory conditions, as well as social trends and adoption of newer technologies.

**Table 2-2: Description of Strategies**

| Strategies | Description |
|---|---|
| A- Base Case | • Represents TVA's current assumptions for resource costs and applies a planning reserve margin constraint, which also applies in every strategy |
| B- Promote DER | • Promotes DER to high long-term penetration levels by incenting distributed solar and storage, combined heat and power, energy efficiency and demand response |
| C- Promote Resiliency | • Promotes small, agile capacity to increase operational flexibility of TVA's power system, while also improving the ability to respond locally to short-term disruptions |
| D- Promote Efficient Load Shape | • Promotes targeted electrification, demand response, and energy management to optimize load shape, including programs targeting low-income energy efficiency |
| E- Promote Renewables | • Promotes renewables at all scales to meet growing prospective or existing customer demands for renewable energy |

## 2.3 Analyze and Evaluate

After the resource planning scenarios and strategies were developed, the performance of each planning strategy was analyzed in detail across all of the scenarios. This phase of the IRP used industry standard capacity expansion planning and production cost-modeling software to estimate the total cost of each combination of strategy and scenario. Metrics, financial risks and environmental impacts were developed from the cost-modeling results.

Unique resource plans, or "portfolios," were developed, one for each combination of scenario and strategy. Each of the 30 portfolios represented a long-term, least-cost plan of different resource mixes that could be used to meet the region's power needs.

Every portfolio was evaluated using metrics within a consistent, standard scorecard. The metrics were chosen based on importance to TVA's mission, and captured financial, environmental, operational and economic impacts. Portfolios were analyzed for their robustness under stress across multiple scenarios and metrics. TVA identified portfolios that performed best overall, and those strategies that performed well in most models of the future.

## 2.4 Present Initial Results and Gather Feedback

The draft 2019 IRP and EIS were released for public review and comment from February 15th, 2019, until April 8th, 2019. It presented an initial range of viable planning strategies for further consideration, and included scorecards and assessments using key metrics, along with an assessment of environmental impacts based on the draft results. As in the scoping period, TVA encouraged public comments on the draft IRP and associated EIS. Over 300 comment submittals were received, along with a petition from the Sierra Club signed by close to 1,000 individuals. The comments expressed public concerns, questions, and recommendations for the future operation of the TVA power system.

## 2.5 Incorporate Feedback and Perform Additional Modeling

Following the public comment period, all comments were reviewed. Similar comments were combined into a group, as appropriate. TVA provided responses to all substantive comments either by revising the IRP or associated EIS, or by providing specific answers in the final EIS. Results of any additional technical analysis conducted to respond to comments are included in the final IRP. Comments received, along with TVA's responses, can be found in Appendix F of the Final EIS.

## 2.6 Identify Target Power Supply Mix

After consideration of IRP Working Group and RERC input, review of the public comments received and additional analysis, TVA identified a target power supply mix based on planning strategies evaluated in the IRP. This target, expressed in ranges, reflects the mix of supply and demand side resources that best position the Valley for success in a variety of alternative futures while preserving the flexibility necessary to respond to uncertainty. Final results and implementation considerations are found in Chapter 9 of the IRP.

## 2.7 Identify Near-Term Actions and Signposts

Considering the IRP key findings and Recommendation for the target power supply mix over the next 20 years, TVA also identified near-term actions that would provide benefit across multiple futures. Additionally, we have highlighted key signposts, or drivers, that will guide decisions in the longer term.

## 2.8 Approval of IRP Recommendations

A Notice of Availability of the final 2019 IRP and EIS has been published in the *Federal Register*. No sooner than 30 days after publication of the Notice of Availability in the Federal Register, the TVA Board of Directors will be asked to approve the recommendations included in the study, including the target power supply mix. The Board will decide whether to approve the recommendations presented in the study, to modify them or to approve an alternative. The Board's decision will be described and explained in a Record of Decision.

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# Chapter 4: Need for Power Analysis

Figure 4-1 is a comparison of weather-normalized actual annual peaks in megawatts (MW) to peaks forecasted one year earlier. The red "Normalized Actual" line represents what the annual peaks would have been under normal weather conditions. The closer the blue-dotted "Forecast" is to the red "Normalized Actual" line, the more accurate the peak forecast. For example, in FY17, the actual peak was only 1.4 percent lower than forecasted.

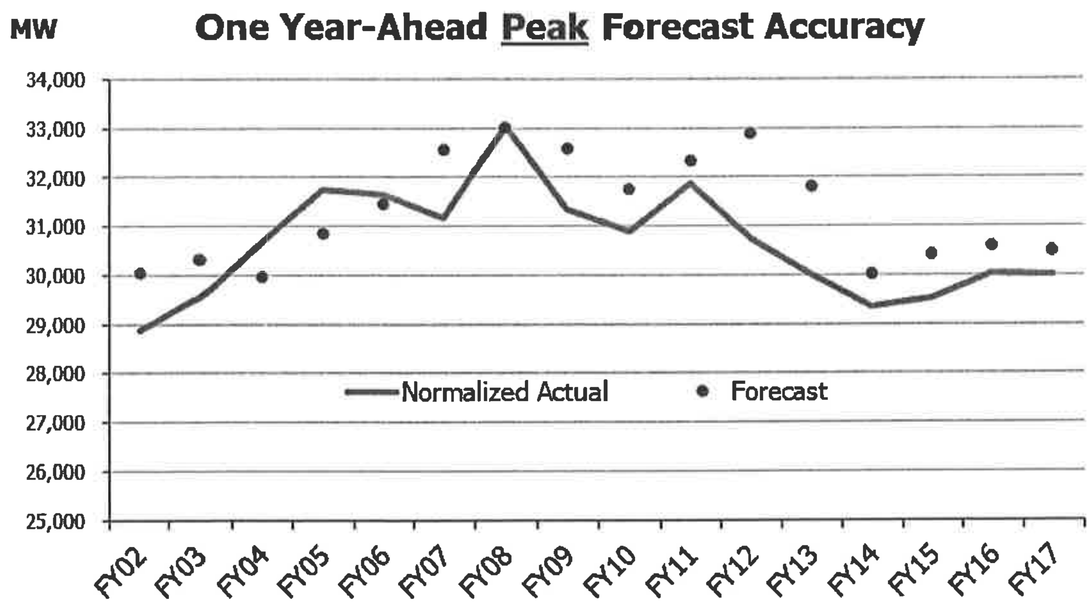


**Figure 4-1: Comparison of Actual and Forecasted Annual Peak Demand**

Figure 4-2 is a comparison of weather-normalized actual annual energy requirements in gigawatt-hours (GWh) to energy forecasts from one year earlier. Energy is somewhat less volatile than peaks, which are based on a single hour of each year, because energy is the sum of all the hours of the year. This difference makes energy easier to forecast; hence, year-ahead forecast variances tend to be smaller.

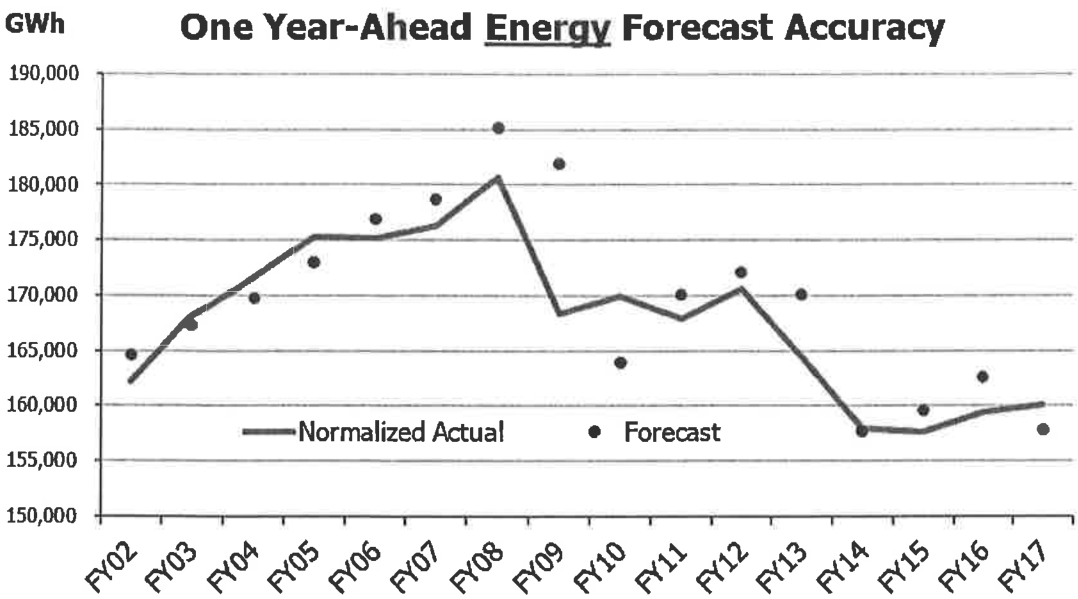


**Figure 4-2: Comparison of Weather-normalized Actual and Forecasted Energy**

Model accuracy is assessed by using historical actuals for forecast variables and checking to see how close the models reproduce historic power demand. R-squared ($R^2$) is a statistical measure of how well the regression predictions approximate real data points. This back testing methodology indicates that TVA's forecast model explains 98 percent of the variation, as measured by the $R^2$, in historic demand and estimates monthly demand within a monthly average absolute error of 1.4 percent. Fundamentally, if TVA had perfect foresight pertaining to the macro environment, the actual demand would be within +/- 1.4 percent. Figure 4-3 compares the back-tested prediction (x-axis) to the actual observations (y-axis).

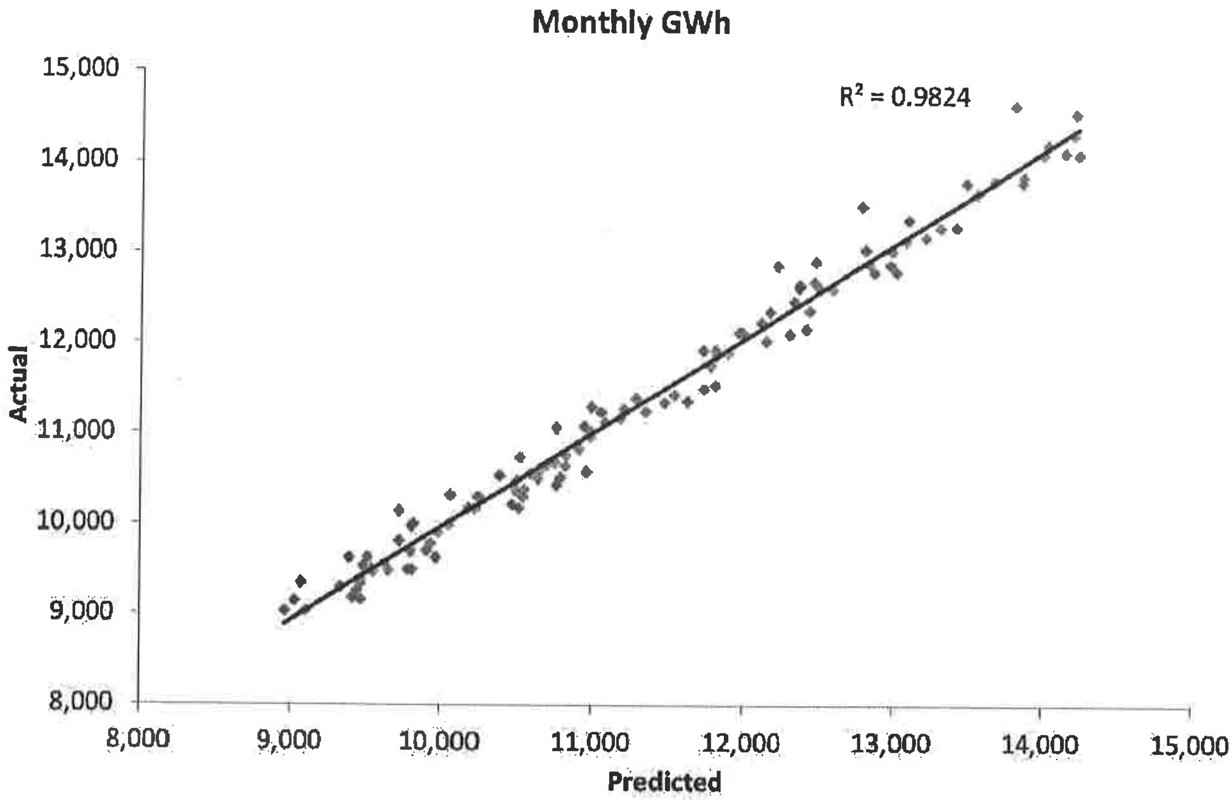


**Figure 4-3: Comparison of Predicted versus Actual Monthly Energy**

The remainder of the forecast error is caused by assumptions about market fundamentals. Forecasts of future economics, demographics and efficiency improvements drive expected demand for power. Variation in the expected business environment manifest as forecast variance. For example, at the height of the Great Recession (FY09), TVA's weather-normalized forecast variance was 8.0 percent and 4.0 percent for System Energy and Peak, respectively, driven by the significant recession that was not part of the economic forecast. Impacts from changes in the underlying market fundamentals highlights the value in scenario analysis.

### 4.1.4 Forecasts of Peak Load and Energy Requirements

Over the next couple of decades, the Current Outlook anticipates system energy to remain flat at a 0.0 percent compound annual growth rate (CAGR) and peak demand to grow at a 0.3 percent CAGR. These forecasts are very similar to the actual growth over the FY02 through FY17 period for energy (-0.1 percent CAGR) and peak (0.3 percent CAGR). These expectations are a function of both economics and energy efficiency projections. Slower economic growth, driven by the baby boomers' retirement, and an ever-tightening regulatory environment are both anticipated to moderate future energy growth.

To deal with the inherent uncertainty in forecasting, TVA uses a range of forecasts. Each forecast corresponds to different scenarios that reflect higher or lower loads compared to the Current Outlook. The Current Outlook scenario for the IRP is the forecast that TVA prepared for the FY19 Long Range Financial Plan in the spring of 2018. The range of forecasts for system peak load and energy requirements in the IRP are shown in Figures 4-4 and 4-5, respectively. Both include the Current Outlook scenario and the highest and lowest growth scenarios that are modeled. They are the Valley Growth scenario and the Rapid DER Adoption scenario, respectively. Annual peak load growth over the 2019 through 2038 time period is 0.3 percent in the Current Outlook scenario and varies from a -0.7 percent CAGR in the lowest peak scenario to a 1.7 percent CAGR in the highest growth scenario. System energy requirements are flat in the Current Outlook scenario with energy declining annually 1.5 percent in the lowest scenario and going as high as 2.0 percent annually in the highest growth scenario.

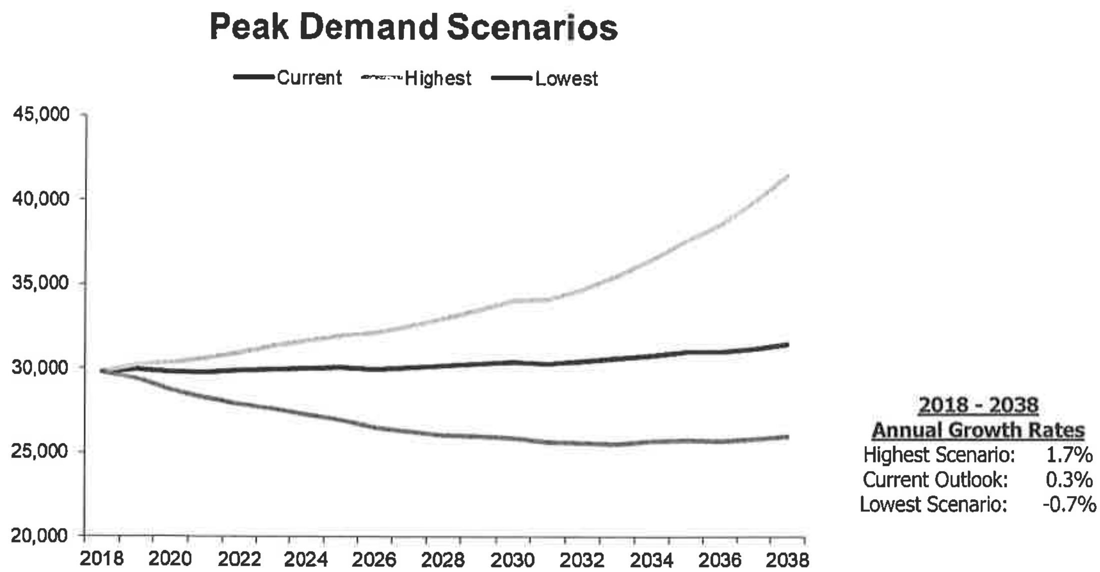


**Figure 4-4: Peak Demand (MW) Forecast**

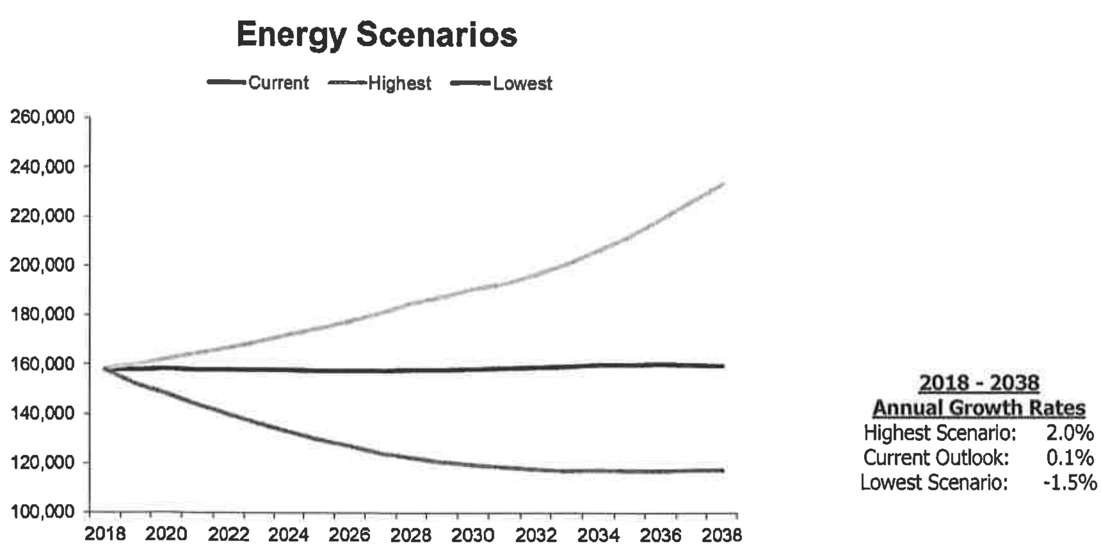


**Figure 4-5: Energy (kW-hours) Forecast**

The use of ranges ensures that TVA considers a spectrum of electricity demand in its service territory and reduces the likelihood that its plans are overly dependent on a single-point estimate of demand growth. Alternative scenarios highlight the risk inherent in forecasting and planning to a single point estimate. The scenario-generated ranges are used to inform planning decisions beyond pure least-cost considerations based on a specific demand in each year.

## 4.2 Determine Reserve Capacity Needs

To maintain reliability, power providers must always have more generating capacity available than required to meet peak demand. This additional generation, called "reserve capacity," must be large enough to cover the loss of the largest single operating unit (contingency reserves), be able to respond to moment-by-moment changes in system load (regulating reserves) and replace contingency resources should they fail (replacement reserves). Total reserves must also be sufficient to cover uncertainties such as unplanned unit outages, undelivered purchased capacity, severe weather events, or load forecasting error.

Through a recent study, TVA identified planning reserve margins for both the summer and winter peak seasons. The reserve margin study is based on a probabilistic analysis that considered the uncertainty of unit availability, transmission capability, weather-dependent unit capabilities (e.g., hydro, wind and solar), economic growth and weather variations to compute expected reliability impacts and costs. TVA selected planning reserve margins for summer and winter that targeted industry best-practice levels of reliability, while also minimizing the cost of reserves and reliability events to the customer. Based on this methodology, TVA's current planning reserve margin is 17 percent above peak load requirements in the summer and 25 percent above peak load requirements in the winter. Additional detail about the Reserve Margin study can be found in Appendix D.

## 4.3 Estimate Supply

The third step in the process of analyzing future power needs is to identify the supply- and demand-side resources currently available to meet future power demand. TVA's generation supply consists of a combination of existing TVA-owned resources; budgeted and approved projects such as new plant additions and updates to existing assets; and existing power purchase agreements (PPAs).

Generating assets can be categorized both by whether the power they produce is used to meet base, intermediate or peak demand or used for storage, and by capacity type or energy/fuel source.

### 4.3.1 Baseload, Intermediate, Peaking and Storage Resources

Figure 4-6 illustrates the uses of baseload, intermediate and peaking assets. Although these categories are useful, the distinction between them is not always clear-cut. For example, a peaking unit, which is typically used to serve only intermittent but short-lived spikes in demand, may be called on from time to time to run continuously for a limited period even though it may be less economical to do so. This may be due to transmission or other power system constraints. Similarly, some baseload units are capable of operating at different power levels, giving them some characteristics of an intermediate or peaking unit. This IRP considered strategies that take advantage of this range of operations.

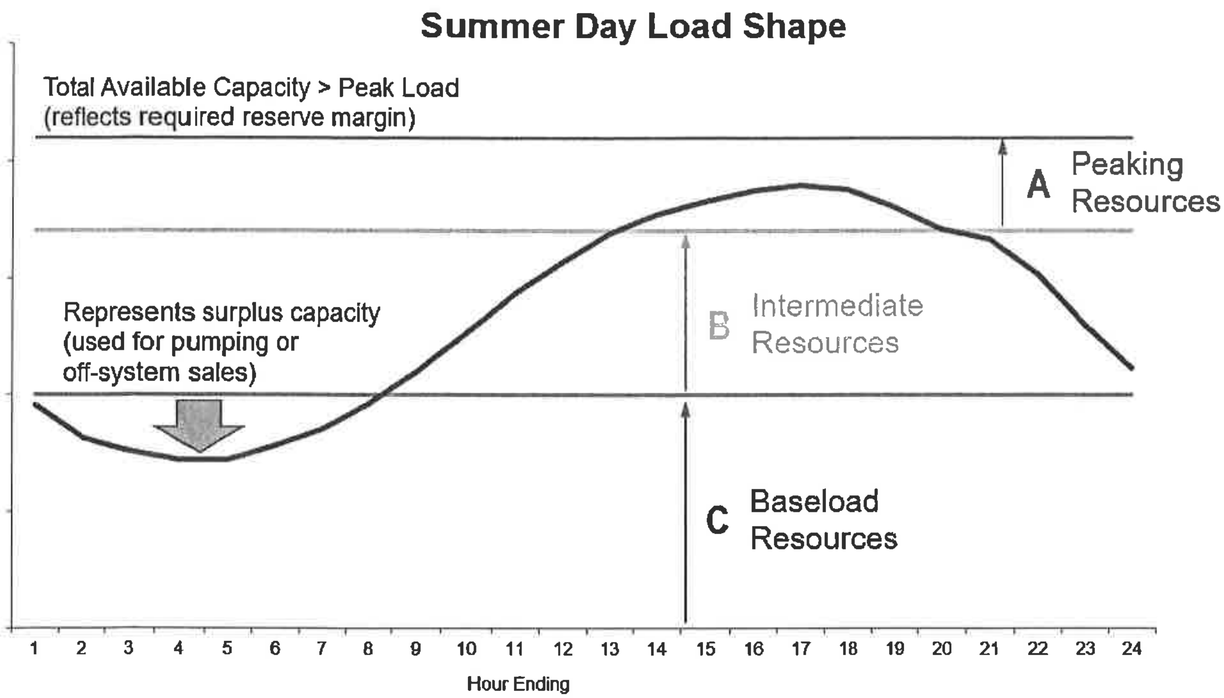


**Figure 4-6: Illustration of Baseload, Intermediate and Peaking Resources**

#### 4.3.1.1 Baseload Resources

Due to their lower operating costs and high availability, baseload resources are used primarily to provide continuous, reliable power over long periods of uniform demand. Baseload resources typically have higher construction costs than other alternatives, but also have lower fuel and variable costs, especially when fixed costs are expressed on a unit basis (e.g., dollars per MWh). An example of a baseload resource is a nuclear power plant.

Some energy providers also use larger coal units and natural gas-fired combined cycle (CC) plants as incremental baseload generators. Natural gas-fired CC plants have become more attractive for baseload generation as the fundamentals of fuel supply and demand have changed and as access to shale gas has grown.

#### 4.3.1.2 Intermediate Resources

Intermediate resources are used primarily to fill the gap in generation between baseload and peaking needs. They also provide backup and balance the supply of energy from intermittent wind and solar generation.

Intermediate units are required to produce more or less output as the energy demand increases and decreases over time, both during the course of a day and seasonally. Given current fuel prices and relative generating efficiencies, these units are typically more costly to operate than baseload units but less expensive than peaking units.

Intermediate generation comes from natural gas-fired CC plants and smaller coal units and also from wind and solar generation. Solar's energy profile aligns more closely with summer load shapes and wind with winter load shapes, and the availability of energy storage technologies increases the ability to leverage these intermittent resources.

Hydro generating assets can generally be categorized as intermediate resources, but their flexibility allows them to operate the full range from baseload to peaking. The limitation of hydro generation is restricted more by water availability and the various needs of the river system such as navigation, flood control and recreation.

#### 4.3.1.3 Peaking Resources

Peaking units are expected to operate infrequently during short-duration, high demand periods. They are essential for maintaining system reliability requirements, as they can start up quickly to meet sudden changes in either demand or supply. Typical peaking resources are natural gas-fired frame combustion turbines (CTs), aeroderivative CTs, reciprocating internal combustion engines (RICE), and conventional hydro generation.

#### 4.3.1.4 Storage Resources

Storage units usually serve the same power supply function as peaking units but use low-cost, off-peak electricity to store energy for generation at peak times. An example of a storage unit is a hydro pumped-storage plant. These plants pump water to a reservoir during periods of low demand and release it to generate electricity during periods of high demand. Consequently, a storage unit is both a power supply source and an electricity user. Lithium-ion batteries are another example of a storage resource.

### 4.3.2 Capacity and Energy

Power system peaks are measured in terms of capacity, the instantaneous maximum amount of energy that can be supplied by a generating plant and collectively by the power system.

For long-term planning purposes, capacity can be defined in several ways:

- **Nameplate capacity** is the theoretical design value or intended maximum megawatt output of a generator at the time of installation.
- **Capability** is the maximum dependable load-carrying ability of units or the number of megawatts that can be delivered by a generating unit without restrictions (i.e., does not reflect temporary capacity restrictions caused by known fuel or mechanical derates) and less station power.
- **Net dependable capacity** is the maximum dependable output less all known adjustments (e.g., transmission restrictions, station service needs and fuel derates) and is dependent on the season. This value, which is used by capacity planners, is typically determined by performance testing during the respective season. TVA uses both summer and winter net dependable capacities of units in the analysis, given the dual-peaking nature of the system.

Overall power system production is measured in terms of energy (i.e., megawatt-hour). Energy is the total amount of power that an asset delivers in a specified time frame. For example, one MW of power delivered for one hour equals one megawatt-hour (MWh) of energy.

The capacity factor of a power plant is a measure of the actual energy delivered by a generator compared to the maximum amount it could have produced at the nameplate capacity. Assets that run constantly, such as nuclear plants, provide a significant amount of energy with capacity factors greater than 90 percent.

Assets that are used infrequently, such as a combustion turbine, provide relatively little energy with capacity factors of typically less than five percent, although the energy they produce is crucial since it is often delivered at peak times.

Variable energy resources such as solar and wind have capacity factors based on their shapes, or pattern of generation across the days and seasons. Utility-scale solar capacity factors can approach 25 percent, and wind capacity factors from Midwest farms average around 40 percent. Capacity factors for these resources vary by location. For example, solar capacity factors in very sunny regions of the U.S. are higher than in less sunny regions, and wind farms in the Midwest plains have higher capacity factors than in-Valley installations.

Capacity Factor Examples

High capacity factor unit:
A 1,200-MW nuclear unit could theoretically produce 10,510 GWh of energy if it ran every hour of the year. After planned annual outages, the unit will typically produce 9,460 GWh or 90 percent of its theoretical capacity.

Low capacity factor unit:
A 250-MW natural gas-fired combustion turbine (CT) unit could theoretically produce 2,190 GWh of energy if it ran every hour of the year. However, CT units generally have a capacity factor less than 5 percent, which means the unit would likely operate about 440 hours of the year and produce about 110 GWh.

Energy efficiency also can be measured in terms of capacity and energy. Even though energy efficiency does not input power into the system, the effect is similar because it represents power that is not required from another resource. Demand response also is measured in capacity and energy. However, unlike energy efficiency, it does not offer a significant reduction in total energy used.

### 4.3.3 Current TVA Capacity and Energy Supply

TVA uses a wide range of technologies to meet the needs of the Valley residents, businesses and industries. Figure 4-7 shows the current projection for capacity demand and for capacity supply from existing resources and power purchase agreements, highlighting the capacity gap. Applying the Base Case strategy, TVA then uses the planning model to optimize the resource portfolio to fill this gap while scheduling the contribution of current energy efficiency, demand response, and renewable programs and considering retirements where economic. The optimized result for the Base Case strategy evaluated in the Current Outlook scenario is shown later in the results section of this document.

Figure 4-7 includes both owned and purchased resources, in megawatts of summer net dependable capacity, and is divided into fuel-type (i.e., nuclear, hydro, coal). The chart builds up from the bottom generally in a baseload, intermediate and peaking order, as some assets can serve dual roles.

Figure 4-7 shows how TVA's existing capacity portfolio is expected to change through 2038. This projection serves as the baseline firm capacity for optimizing all portfolios. The existing assets only include resources that currently exist; assets that are under contract; TVA Board-approved changes to existing resources such as refurbishment projects; and TVA Board-approved additions. Existing resources decrease through 2038 primarily because of the retirement of coal-fired units and the expiration of existing contracts (power purchase agreements). The renewable component of the existing portfolio is primarily composed of wind PPAs that expire in the early 2030s. Because the power generated from wind and other renewable resources is intermittent, the firm capacity (or the amount of capacity that can be applied to firm requirements) for these assets is lower than the nameplate capacity. Figure 4-8 identifies expiring and retiring resources that are currently on the TVA system and their respective capacities.

Having a diverse portfolio of resource types – coal, nuclear, hydro, natural gas and renewable resources – and being able to use these resources in different ways enables TVA to provide reliable, low-cost power while minimizing the risk of disproportionate reliance on any one type of resource.

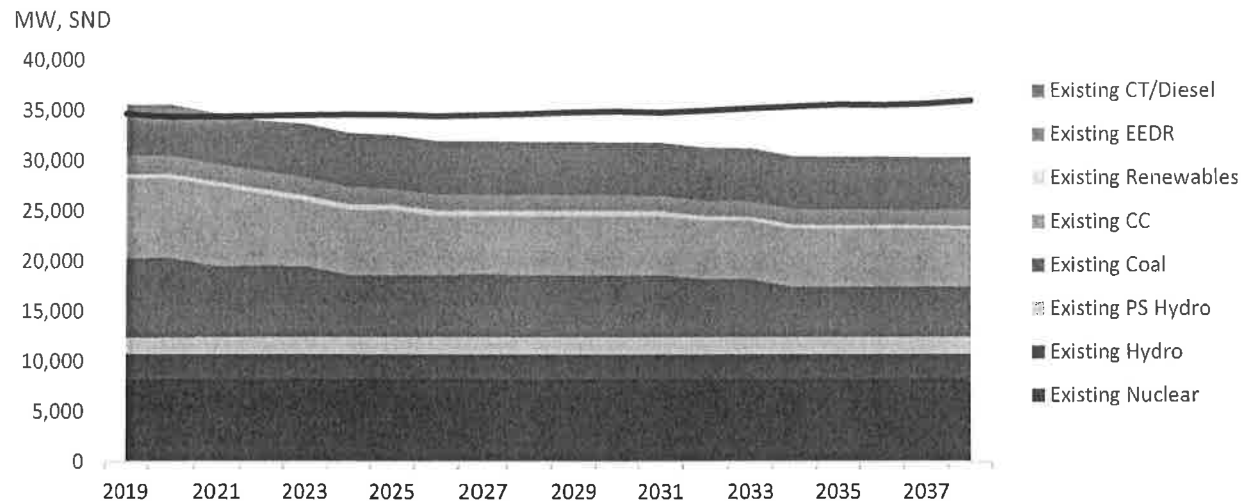


**Figure 4-7: Baseline Firm Capacity, Summer Net Dependable MW**

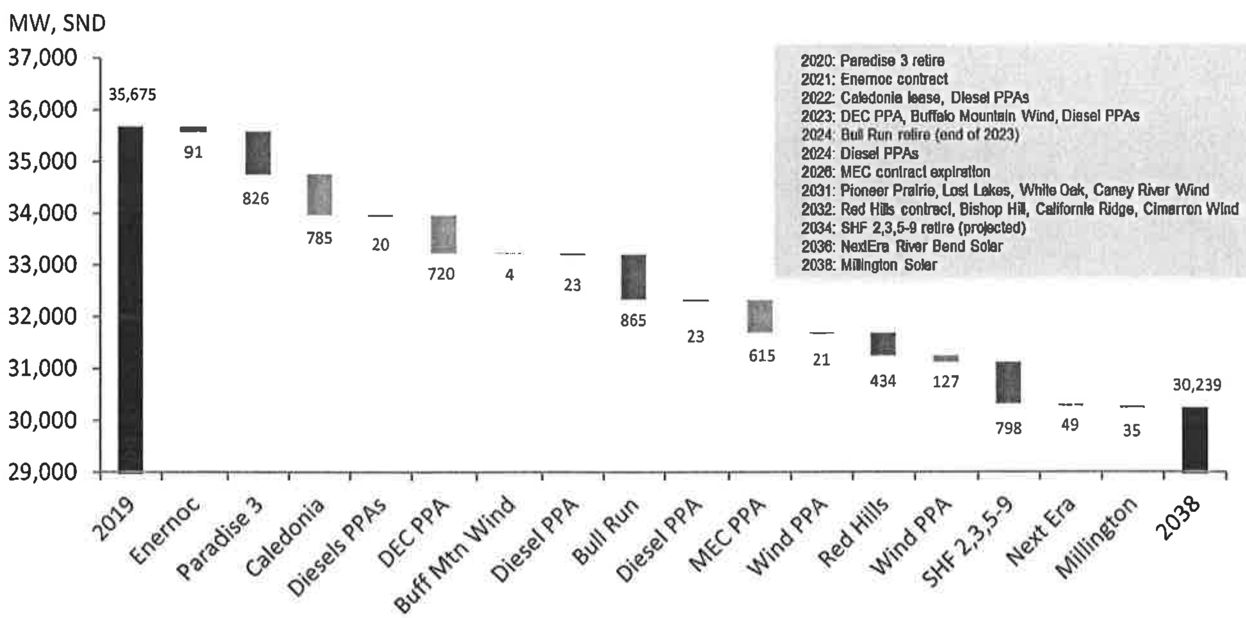


**Figure 4-8: Changes in Baseline Firm Capacity, Summer Net Dependable MW**

Approximately 36 percent of TVA's capacity is currently sourced from emission-free assets such as nuclear power, renewable resources including hydro, and interruptible load management. The renewable category shown throughout this document is based on modeled outputs of energy from renewable sources such as wind, solar, and biomass. This metric is not intended to represent a quantity of certified renewable energy credits.

In FY18, 39 percent of TVA's energy was produced from the nuclear fleet. Coal plants produced about 21 percent of the generation, while the gas fleet produced about 26 percent. Hydro plants produced approximately 10 percent, and 3 percent was produced from wind and solar sources. The remaining one percent results from TVA programmatic energy efficiency efforts, which have been reduced due to increasingly effective USDOE codes and standards.

### 4.3.4 Calculate the Capacity Gap

As noted previously, a capacity gap is the difference between total supply and total demand. More specifically, it is the difference in megawatts between a power provider's existing firm capacity and the forecast annual peak adjusted for any interruptible customer loads and long-term planning reserve requirements (i.e., (i.e., 17 percent for summer and 25 percent for winter).

Figure 4-9 shows TVA's estimated capacity gap or shortfall based on the existing firm capacity and the annual firm requirement for the Current Outlook scenario for the summer and winter peaks. The aim of the IRP is to evaluate strategies and portfolios to meet the capacity gap across a wide range of potential future scenarios.

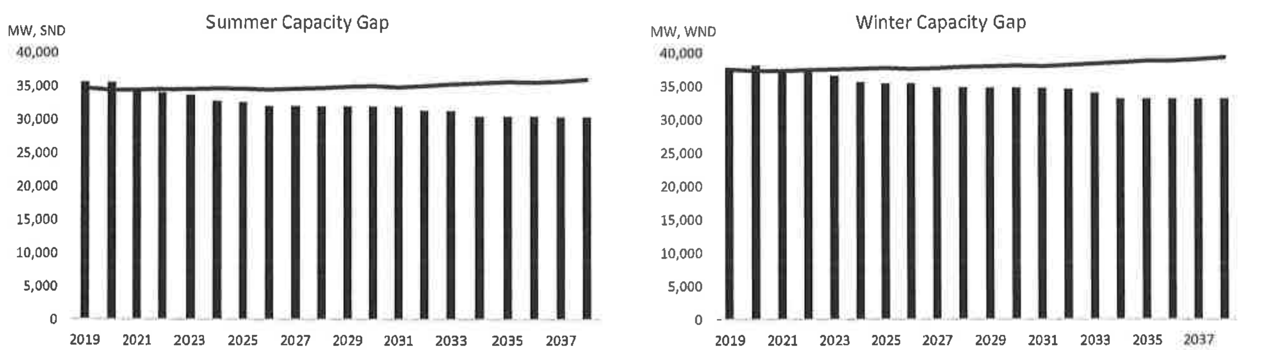


**Figure 4-9: Estimating the Capacity Gap**

TVA also considers the capacity gaps that might occur within the other scenarios. Figure 4-10 shows the range of capacity gaps corresponding to all the scenarios, ranging from the Valley Load Growth scenario on the high end to the Rapid DER Adoption scenario on the low end. All scenarios are described in detail in Chapter 6.

When optimizing the portfolio, power system analysis evaluates the most economical way to meet the capacity gap and associated energy needs, considering resource options and promotions applicable in each strategy.

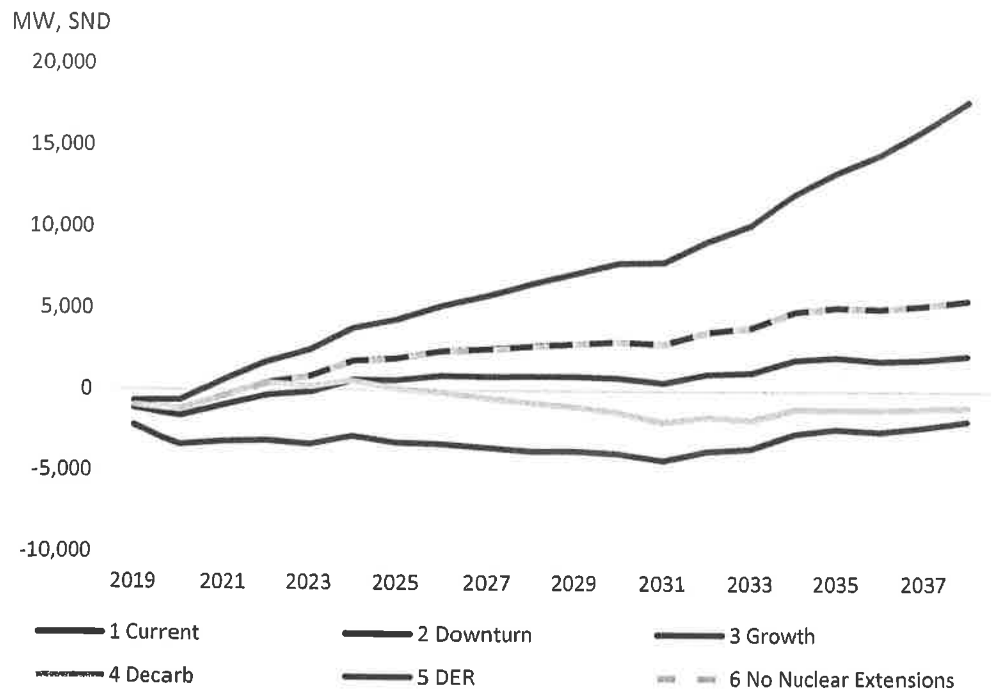


**Figure 4-10: Capacity Gap Range**

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# 5 Energy Resource Options

Maintaining the diversity of energy resources is fundamental to TVA's ability to provide low-cost, reliable and clean electric power to Valley residents, businesses and industries. For this reason, TVA considered the addition of a wide range of supply-side generating resources, as well as energy efficiency and other demand-side resource options, to fill the forecasted 20-year capacity and energy gaps identified through the power needs analysis described in Chapter 4.

The power needs analysis indicates that, under the Current Outlook scenario, TVA will require additional capacity and energy of about 1,200 MW and 7,100 GWh by 2028, growing to about 4,400 MW and 13,800 GWh by 2038.

## 5.1 Energy Resource Selection Criteria

During the scoping process, TVA identified a broad range of energy resources that could be used to fill the predicted capacity and energy gaps. The next two sections explain the criteria that were used to reduce this list to a manageable portfolio of expansion options. For a complete list of resource options considered, see Chapter 5, Energy Resource Options, of the associated EIS.

### 5.1.1 Criteria for Considering Resource Options

Two criteria were used to ensure that only viable energy resource options were considered in the IRP analysis. To be considered, resource options must:

- Use a proven technology, or one that has reasonable prospects of becoming commercially available in the planning horizon
- Be available to TVA within the region or be available to be imported through market purchases.

Technology is a key factor in TVA's ability to fulfill its mission in a balanced way. TVA continues to pursue technological advances to become more efficient and sustainable. As part of its mission under the TVA Act, the agency is called upon to be a leader in technology innovation.

In the 2015 IRP, DER was included in the load forecast as a load modifier that reduced demand for electricity from TVA, and energy efficiency and demand response were modeled as selectable resources. In the 2019 IRP, TVA has made further refinements in modeling behind-the-meter generation in the load forecast, including variations across the scenarios. We have also modeled distributed generation resources, including combined heat and power, and distributed solar and storage. There are targeted levels of adoption of these distributed resources based on incentive levels in each strategy. Further information on how these resources were modeled is included in Appendices A, B and C.

### 5.1.2 Criteria Required for Resource Options

To compare energy resource options available for new generation objectively, it is important to have consistent data regarding the cost and operating characteristics of each option. A list of characteristics used in the 2019 IRP are identified and defined in Table 5-1 and Table 5-2. Section 5.2.2 provides the numerical values for some of these parameters for the new assets.

**Table 5-1: Cost Characteristics**

| Type of Characteristic | Description |
|---|---|
| Cost characteristics | |
| Unit capital costs | Each technology type must have a representative $/kW unit, which is considered a total installed cost. Total installed cost includes equipment, engineering and interest during construction in present day dollars. |
| Capital escalation rates | Since capital costs typically increase over time, TVA assumes that capital costs escalate at the forecast rate of inflation for most resources. However, some energy technologies (e.g. solar and battery storage) are rapidly evolving, so TVA assumes declining costs for these resources. |
| Construction spend schedule | Some technologies take a long time to build. Construction times for nuclear units, for example, average about 10 years. To estimate the cash flow for the construction of a long-lead time build unit such as a nuclear unit, the percent of total capital dollars spent in each year is required. This metric is typically not needed for renewable assets which are smaller in scale and generally built in less than a year. |
| Fixed operating and maintenance costs (FOM) | FOM costs are independent of the number of hours of operation or amount of electricity produced and are generally expressed in dollar per kilowatt per year ($/kW-yr). FOM includes operating and maintenance labor, plant support equipment, administrative expenses and fees required by regulatory bodies. |
| Variable operating and maintenance costs (VOM) | VOM costs are dependent on the number of hours of operation and are generally expressed as a dollar per megawatt-hour ($/MWh). VOM costs include consumables like raw water, waste and water disposal expenses, and chemicals and reagents. VOM costs do not include fuel expenses. |
| Fuel expenses | Fuel is the material that is consumed to generate electricity – for example, coal, natural gas, uranium and biomass. These costs are typically expressed in dollar per million British thermal units ($/mmBtu) and include the delivery charges. |
| Transmission | A new generating resource has to be connected to the transmission system. Costs are typically expressed in a dollar per kilowatt ($/kilowatt) unit. |
| Integration cost | Intermittent resources require the balance of system resources to absorb sub-hourly fluctuations, driving an integration cost. Further details on the cost study are included in Appendix D. New solar and wind resources have integration costs, expressed in $/MWh. |
| Flexibility benefit | Highly flexible resources provide a sub-hourly benefit associated with ability to more efficiently absorb sub-hourly fluctuations in intermittent resources. Further details on the benefit study are included in Appendix D. New aeroderivative CTs and utility battery storage resources have flexibility benefits, expressed in $/kW. |

**Table 5-2: Operating Characteristics**

| Type of Characteristic | Description |
|---|---|
| Operating characteristics | |
| Net dependable capacity | Each unit must have a summer and winter net dependable capacity rating in megawatts. |
| Capacity credit | The capacity credit is the amount of capacity immediately available at the highest demand times. The capacity credit must be estimated for variable units or non-dispatchable resources. |
| Full load heat rate | A heat rate must be specified for each unit for summer and winter. A heat rate is a measure of the consumption of fuel necessary for a unit to produce electricity. Heat rates are expressed in British thermal units per kilowatt hour (Btu/kWh) and are based on a full-load heat rate. Heat rates are considered long-term planning assumptions and include the expected degradation in the heat rate of a unit after the first two years. Although a heat rate is not typically associated with a nuclear unit, one is necessary to model the fuel costs. |
| Unit availability | A date when each unit would be available for operation must be specified. Unit availability is restricted by technical feasibility or commercial availability, as well as permitting and construction times. For example, if it takes five years to build a combined cycle plant, then a new CC could not be selected prior to five years into the planning horizon. |
| Book life | The book life of a unit is the number of years a resource is expected to be in service for accounting purposes. Book life is the financial payback period which represents the amount of time the asset is expected to be used and useful. A license extension, beyond the original asset life, is not assumed with any new generating option. |

## 5.2 Resource Options Included in IRP Evaluation

TVA's existing assets, budgeted and approved projects, and power purchase agreements are considered as the baseline firm capacity in the IRP evaluation. These assets are generally expected to continue operating through the duration of the planning period or through the terms of existing power purchase agreements and other contracts, where applicable.

Options to meet the forecast net system requirements identified in Chapter 4 include:

- Building new generating units
- Entering into new power purchase agreements
- Developing energy efficiency and demand response programs
- Retiring existing resources

The next two sections describe existing and potential new generation by resource category, as well as retirement options. For a comprehensive description of all resource option attributes, characteristics and technologies, see Chapter 5, Energy Resource Options, of the associated EIS.

### 5.2.1 Existing Assets by Resource Category

#### 5.2.1.1 Nuclear

TVA currently operates seven nuclear reactors: three at Browns Ferry Nuclear Plant, two at Sequoyah Nuclear Plant and two at Watts Bar Nuclear Plant. These plants have a combined generating capacity of about 7,700 MW. Extended power uprates for the three Browns Ferry units have been approved by the TVA Board and will be completed by the end of 2019. These uprates will add about 450 MW of additional capacity at the Browns Ferry plant.

The three units at Browns Ferry Nuclear Plant have license expiration dates of 2033, 2034, and 2036, respectively. TVA will evaluate non-renewal of these licenses in the No Nuclear Extensions scenario, where no nuclear units in the U.S. will be allowed to operate beyond 60 years. All other scenarios assume that TVA is granted a Second License Renewal (SLR) by the Nuclear Regulatory Commission (NRC). The two units at Sequoyah are licensed for operation through 2040 and 2041, respectively. Watts Bar Unit 1 is licensed for operation through 2035 (initial 40 year license), and Watts Bar 2 began commercial operation in October 2016.

#### 5.2.1.2 Coal

TVA operates six coal-fired power plants consisting of 26 active generating units with a total capability of almost 7,900 MW. TVA uses a value lower than the capability of a resource, based on its summer and winter net dependable capacity. Table 5-3 is a snapshot of the planning assumptions for the coal units, including the forecasted retirement of the uncontrolled Shawnee units in 2034 to meet air quality standards. Following detailed evaluation, on February 14, 2019, the TVA Board of Directors voted to retire Paradise Unit 3 by the end of 2020 and Bull Run by the end of 2023. All cases reflect retirements of these units in 2020 and 2023, respectfully.

In addition to TVA-owned coal-fired units, TVA has access to the output from a coal-fired power plant with a generating capacity of about 440 MW through a long-term power purchase agreement that expires in 2032.

#### 5.2.1.3 Natural Gas

TVA operates 87 natural gas-fired combustion turbines (CT) at nine power plants with a combined generating capability of about 5,700 MW and 14 combined cycle (CC) units at eight plants with approximately 6,800 MW of capability. TVA has power purchase agreements for about 1,300 MW of capability from two merchant combined cycle gas plants, with agreements expiring in the early to mid-2020s.

#### 5.2.1.4 Petroleum Fuels

TVA currently owns five diesel generators with a total capability of 9 MW.

**Table 5-3: Coal Fleet Portfolio Plans**

| Coal Plant | Total Number of Original Units | Current Operating Status | Operational Plan |
|---|---|---|---|
| Allen | 3 | Retired | |
| Bull Run | 1 | Operational | Retire by end of 2023 |
| Colbert | 5 | Retired | |
| Cumberland | 2 | Operational | Continue to operate |
| Gallatin | 4 | Operational | Continue to operate |
| John Sevier | 4 | Retired | |
| Johnsonville | 10 | Retired | |
| Kingston | 9 | Operational | Continue to operate |
| Paradise | 3 | Units 1-2 Retired<br>Unit 3 Operational | Retire Unit 3 by end of 2020 |
| Shawnee | 10 | Units 1-9 Operational<br>Unit 10 Retired | Retire Units 2,3,5-9 in 2034 |
| Widows Creek | 8 | Retired | |

#### 5.2.1.5 Hydro

TVA operates 109 conventional hydro generating units at 29 dams. These units have the capability to generate about 3,800 MW of electricity. All IRP portfolios reflect investing in and maintaining TVA's existing hydroelectric fleet. TVA has completed 60 hydro unit modernization projects out of 109 conventional hydro units. TVA plans to modernize two to three units per year, and the program is perpetual in nature to maintain capacity over time.

In addition, TVA has a long-term power purchase agreement with the U.S. Army Corps of Engineers for eight dams on the Cumberland River system. These facilities provide about 400 MW of capability.

TVA anticipates about 70 percent of this hydro capability to be available at the summer peak hour, given the operational constraints of the hydro units.

#### 5.2.1.6 Energy Storage

TVA operates one large energy storage facility. The Raccoon Mountain Pumped-Storage Plant has four generating units with a Summer Net Dependable (SND) capacity of about 1,600 MW. Raccoon Mountain is TVA's largest hydro facility and provides critical flexibility to the TVA system by storing water at off-peak times for use when demand is high.

#### 5.2.1.7 Wind

TVA purchases all of the power produced by the Buffalo Mountain wind farm in Anderson County, Tennessee. Buffalo Mountain is one of the largest wind farms in the Southeast, with 15 turbines and 27 MW of nameplate capacity. As defined in section 4.3.2, the nameplate capacity is the maximum technical output of a generator, or the theoretical design value.

TVA has long-term power purchase contracts with seven wind farms located in Illinois, Kansas and Iowa. These facilities provide about 1,200 MW of nameplate capacity. TVA anticipates about 14 percent and 31 percent of the nameplate to be available for peak summer and winter requirements, respectively. These agreements expire in the early 2030s. TVA obtains the renewable energy credits from these farms. Renewable energy credits are a separate commodity formed from the production of energy at designated sites.

#### 5.2.1.8 Solar

TVA owns 14 photovoltaic (PV) installations with a summer capability of approximately 1 MW. TVA also purchases solar power through several programs and long-term power contracts totaling 370 MW of nameplate capacity with about 250 MW expected to be available at the summer peak hour. TVA obtains the renewable energy credits from these sites, and the existing PPAs extend through the late 2030s. Solar power purchase agreements signed subsequent to the spring of 2018 when baseline firm capacity was established for this IRP are not included in existing assets. This includes agreements signed for about 700 MW of solar nameplate capacity to meet specific customer needs.

#### 5.2.1.9 Biomass

TVA purchases about 50 MW of biomass-fueled generation through existing programs.

#### 5.2.1.10 Energy Efficiency

TVA's energy efficiency portfolio focuses on reduction in peak demand and energy savings. From FY07-FY18, these efforts contributed about 400 MW of summer peak demand reduction and saved about 2450 GWh of energy annually. These savings are adjusted for applicable transmission and distribution (T&D) losses, free rider/driver discounts, realization rates, and performance adjustments for actual weather.

#### 5.2.1.11 Demand Response

Demand response programs focus on reduction of peak demand. Under these programs, TVA direct-served customers and local power companies can reduce their power bills by allowing TVA to suspend availability of power in the event of a power system, economic, or reliability need. These programs provide about 1800 MWs of peak reduction.

### 5.2.2 New Assets Considered by Resource Category

A complete list of viable new resource options for evaluation in this IRP is provided below. All options are based on a generic location and unit availability rounded to the next full year. A detailed discussion by resource category follows.

With a focus on DERs in this IRP, TVA also leveraged input from the Distributed Generation Information Exchange (DGIX) to inform resource characteristics and costs. DGIX input specifically helped inform inputs for distributed solar and storage, CHP, and electric vehicles.

An independent third-party reviewed and compared the parameters to proprietary and other industry sources to ensure the modeled unit characteristics and assumptions were representative of the respective generating technologies. See Appendix A for the letter summary of the benchmarking efforts of Navigant Consulting, Inc. as well as a brief discussion of TVA's internal benchmarking on resource costs ($/kW).

**Nuclear**
- Pressurized Water Reactor (PWR)
- Advanced Pressurized Water Reactor (APWR)
- Small Modular Reactor (SMR)

**Coal**
- Supercritical Pulverized Coal 1x8
- Supercritical Pulverized Coal 2x8
- Integrated Gasification Combined Cycle (IGCC)
- Integrated Gasification Combined Cycle with Carbon Capture and Storage (IGCC CCS)
- Supercritical Pulverized Coal 1x8 with Carbon Capture and Storage
- Supercritical Pulverized Coal 2x8 with Carbon Capture and Storage

**Natural Gas**
- Combustion Turbine 6x (LMS 100)
- Combustion Turbine 4x (LMS 100)
- Combustion Turbine 2x (LMS 100)
- Combustion Turbine 3x (7FA)
- Combustion Turbine 4x (7FA)
- Combined Cycle 1x1
- Combined Cycle 2x1
- Combined Cycle 3x1
- Combined Cycle Supplemental Duct-firing (1x1, 2x1, 3x1)
- Combined Cycle With Carbon Capture and Storage
- Reciprocating Internal Combustion Engine (RICE) 12x
- Reciprocating Internal Combustion Engine (RICE) 6x
- Reciprocating Internal Combustion Engine (RICE) 2x
- Commercial & Industrial Combined Heat and Power (CHP)

**Hydroelectric**
- Hydro Spill Addition
- Hydro Space Addition
- Hydro Run of River

**Energy Storage**
- Pumped Storage
- Utility Battery Storage
- Residential Battery Storage
- Compressed Air Energy Storage (CAES)
- Fuel Cells
- Advanced Chemistry Battery

**Wind**
- Midcontinent Independent System Operator (MISO)
- Southwest Power Pool (SPP)
- In-Valley
- High Voltage Direct Current (HVDC)

**Solar**
- Utility-scale Single-axis Tracking
- Utility-scale Fixed-Axis
- Large Commercial-scale
- Small Commercial-scale
- Residential Scale

**Biomass**
- New Direct Combustion Biomass
- Repowering Existing Coal with Biomass

**Energy Efficiency**
- Residential
- Commercial
- Industrial

**Demand Response**

**Electrification**

**Retirement Options**
- Gas Combustion Turbines > 40 years old (as early as 2020)
- Uncontrolled Shawnee units (as early as 2020)
- All Other Coal Units (as early as 2025)
- Browns Ferry Nuclear Units 1-3 (as early as 2033)

**Figure 5-1: List of New Assets**

#### 5.2.2.1 Nuclear

There are three nuclear expansion options available to fill the expected capacity gap: a Pressurized Water Reactor (PWR), an Advanced Pressurized Water Reactor (APWR) and a Small Modular Reactor (SMR).

SMRs are a new type of nuclear reactor in which the components are manufactured in a factory and then assembled together onsite. The individual units are smaller in size, allowing for increased flexibility in installation and use. New units could be located at existing nuclear plants or at other sites beneficial to the transmission system or local resiliency.

As mentioned previously in Chapter 4, the retirement of the three Browns Ferry units is being evaluated in the No Nuclear Extensions scenario. In this scenario, it was mentioned there could be subsidies to drive small modular reactor technology advancements and improved economics. What is contemplated is more about demonstrating modular construction processes efficiently in a nuclear application, in order to reduce cost and schedule uncertainties for subsequent SMR facilities. Strategy C, which emphasizes small, agile resources, includes two SMRs totaling 1,200 MW forced in to replace one of three Browns Ferry units.

Table 5-4 shows some of operating characteristics used to model each option. Summer net dependable capacity, summer full load heat rate, unit availability and book life are explained earlier in this section. The annual outage rate percentage includes forced and planned outages. See Chapter 4, Section 4.3.2, for a discussion of the different types of capacity ratings.

**Table 5-4: Nuclear Expansion Options**

| Unit Characteristics | PWR | APWR | SMR |
|---|---|---|---|
| Summer Net Dependable Capacity (MW) | 1,260 | 1,117 | 600 |
| Summer Full Load Heat Rate (Btu/kWh) | 9,853 | 9,715 | 10,046 |
| Unit Availability (Yr) | 2029 | 2029 | 2025 |
| Annual Outage Rate (%) | 10% | 10% | 10% |
| Book Life (Yrs) | 40 | 40 | 40 |

### 5.2.2.2 Coal

The 2019 IRP includes six coal expansion options, including two integrated gas combined cycle (IGCC) options and four supercritical pulverized coal (SCPC) options as shown in Table 5-5.

IGCC technology converts coal into gas. One IGCC option has carbon capture and sequestration (CCS) and one does not. The CCS technology option is assumed to be commercially available starting in 2028 and has a 90 percent carbon dioxide ($CO_2$) capture rate. Coal units typically have a $CO_2$ emission rate of 205 pounds per million BTUs of coal burned; therefore, the CCS technology would reduce the $CO_2$ rate to 20.5 pounds per million BTUs of coal burned. The modeled $CO_2$ emissions incur an emission penalty in the form of a dollar per ton of $CO_2$ emitted.

Two of the four SCPC options have one steam generator with a supercritical steam cycle. One of these options includes CCS technology; the other does not. The other two SCPC options have two steam generators with supercritical steam cycles. Again, one of these options includes CCS technology, and one does not.

In addition to the approved retirements of Paradise Unit 3 in 2020 and Bull Run in 2023, there are several additional coal retirement options available for model selection:

- Uncontrolled Shawnee Units (2,3,5-9) as early as 2020
- All other coal units as early as 2025

**Table 5-5: Coal Expansion Options**

| Unit Characteristics | IGCC | IGCC CCS | SCPC 1x8 | SCPC 2x8 | SCPC 1x8 CCS | SCPC 2x8 CCS |
|---|---|---|---|---|---|---|
| Summer Net Dependable Capacity (MW) | 550 | 515 | 800 | 1,600 | 617 | 1,200 |
| Summer Full Load Heat Rate (Btu/kWh) | 8,000 | 10,412 | 8,674 | 8,674 | 11,965 | 10,843 |
| Unit Availability (Yr) | 2027 | 2028 | 2030 | 2030 | 2030 | 2030 |
| Annual Outage Rate (%) | 17% | 15% | 10% | 10% | 10% | 11% |
| Book Life (Yrs) | 40 | 40 | 40 | 40 | 40 | 40 |

### 5.2.2.3 Natural Gas

The IRP evaluation includes three reciprocating internal combustion engine (RICE) options, five simple cycle combustion turbine (CT) options, and four combined cycle (CC) natural gas fueled options. The RICE engines are available in packages of two, six, or twelve engines. The simple cycle frame CTs are available with either three or four turbines. The other three CT options are aeroderivatives in packages of two, four, or six turbines as shown in Table 5-6.

The CC options have one turbine and one steam generator (CC 1 by 1), two turbines and one steam generator (CC 2 by 1), or three turbines and one steam generator (CC 3 by 1). CC units have supplemental capacity termed duct-firing capacity that adds approximately 100 MW to the base capacity shown. The fourth CC option is a 3 by 1 integrated gasification combined cycle (IGCC) with carbon capture and storage (CCS). The $CO_2$ emission rate for a typical gas unit is 117 pounds of $CO_2$ per million Btus of gas burned. The modeled gas units incur emission charges based on a dollar-per-ton emission penalty for those scenarios with a $CO_2$ penalty.

In addition to options for TVA to build gas-fueled units, the IRP evaluation includes options for continuing to purchase power from existing merchant gas plants or acquiring those plants. PPAs are available for selection based on competitive information which cannot be disclosed. PPA options are evaluated similar to build options with a few slight differences. One difference is that when present value revenue requirements resulting from the expansion model selections are converted into cash flows, then the build options have significant capital expenditures that match the construction spend schedule (noted in section 5.1.2) versus the PPA options which have levelized cash flow payments based on the terms of the contract (similar to a mortgage). The other difference for PPAs is that if the asset is located outside of the TVA transmission area, then the necessary transmission wheeling charges are included.

Combined heat and power (CHP), a distributed gas resource, is offered as an option. Rather than being selectable, various levels of CHP adoption are included to represent consumer response to incentive levels applicable in each strategy, as described in Appendix F.

In addition, there are options for retirement of TVA's older simple cycle frame CTs as early as 2020.

**Table 5-6: Gas Expansion Options**

| Unit Characteristics | RICE 2X | RICE 6X | RICE 12x | LMS100 2X | LMS100 4X | LMS100 6X |
|---|---|---|---|---|---|---|
| Summer Net Dependable Capacity (MW) | 36 | 113 | 226 | 192 | 384 | 576 |
| Summer Full Load Heat Rate (Btu/kWh) | 8,266 | 8,266 | 8,266 | 9,350 | 9,150 | 9,150 |
| Unit Availability (Yr) | 2023 | 2023 | 2023 | 2023 | 2023 | 2023 |
| Annual Outage Rate (%) | 4% | 4% | 4% | 3% | 3% | 3% |
| Book Life (Yrs) | 30 | 30 | 30 | 30 | 30 | 30 |

**Table 5-6: Gas Expansion Options (con't)**

| Unit Characteristics | 7FA CT 3X | 7FA CT 4X | CC 1x1 | CC 2x1 | CC 3x1 | CC 3X1 CCS |
|---|---|---|---|---|---|---|
| Summer Net Dependable Capacity (MW) | 703 | 934 | 591 | 1,182 | 1,773 | 1,593 |
| Summer Full Load Heat Rate (Btu/kWh) | 10,132 | 10,132 | 6,520 | 6,520 | 6,520 | 7,530 |
| Unit Availability (Yr) | 2023 | 2023 | 2023 | 2023 | 2023 | 2028 |
| Annual Outage Rate (%) | 4% | 4% | 7% | 7% | 7% | 7% |
| Book Life (Yrs) | 30 | 30 | 30 | 30 | 30 | 30 |

### 5.2.2.4 Petroleum Fuels

TVA expects to phase out petroleum power purchases by 2028. There are no diesel fuels or other petroleum-based resource options as a primary fuel source under consideration in the IRP because of emissions from these facilities.

### 5.2.2.5 Hydro

Two new hydro projects are included in the IRP evaluation. They include adding additional hydro turbines to existing dam facilities where there is space available with structural modifications. The other project would add turbines at existing dam facilities where water that is now spilled could be used to power more turbines.

Both projects are similar to the larger TVA hydro system and are energy-limited units. Energy-limited units are resources that cannot be dispatched (in the model) based on price ($/MWh) as are traditional thermal generating resources, such as nuclear, coal and gas. Hydropower cannot be dispatched based on price alone because water releases in the Tennessee River system also are required for municipal and industrial uses, navigation, flood damage reduction, recreation, water quality and other purposes. For this reason, TVA includes a fixed amount of monthly energy in the model for conventional hydro stations. The model then uses the hydro energy to level the load shape served by other stations.

Since hydro plants do not use fuel, a heat rate is not needed for modeling.

Small- and low-head hydropower, called run of river, also is included as an IRP resource option. The hydro expansion options are shown in Table 5-7.

**Table 5-7: Hydro Expansion Options**

| Unit Characteristics | Dam Spill Addition | Dam Space Addition | Run of River |
|---|---|---|---|
| Summer Net Dependable Capacity (MW) | 40 | 30 | 25 |
| Unit Availability (Yr) | 2023 | 2023 | 2023 |
| Annual Outage Rate (%) | - | - | 4% |
| Book Life (Yrs) | 40 | 40 | 40 |

### 5.2.2.6 Energy Storage

The IRP evaluation includes a new hydro pumped-storage unit as a resource option. The pumped-storage option would use three reversible turbine generators to either take electricity from the grid by pumping water into a higher altitude reservoir during periods of excess power or add electricity to the grid by using the pumped water to power a turbine as it falls from the upper to the lower reservoir.

A compressed air energy storage (CAES) option also is included. A CAES plant is similar to a pumped-storage plant but, instead of pumping water from a lower to an upper reservoir, a gas turbine is used to compress air often into an underground cavern where it can be stored under pressure until electricity is required. The pressurized air is then heated and directed through a conventional generator to produce electricity.

Battery storage is included as an option at the utility scale and the residential scale. Rather than being selectable, distributed storage is modeled at various levels of adoption to represent consumer response to incentive levels applicable in each strategy, as described in Appendix F. TVA is also including fuel cells and advanced chemistry batteries as options in this IRP. The storage options are shown in Table 5-8.

Storage efficiency is included in modeling all these energy storage options because of the energy losses inherent to the energy conversion process and due to the loss of water or air during storage. The storage efficiency percentage for these energy storage options represents the efficiency of one cycle (i.e., pumping water, then releasing).

**Table 5-8: Storage Options**

| Unit Characteristics | Utility Battery | Pumped Storage | CAES | Fuel Cell | Adv. Chem. Batt. |
|---|---|---|---|---|---|
| Summer Net Dependable Capacity (MW) | 100 | 850 | 330 | 25 | 25 |
| Summer Full Load Heat Rate (Btu/kWh) | - | - | - | 6,824 | - |
| Unit Availability (Yr) | 2023 | 2028 | 2024 | 2023 | 2023 |
| Annual Outage Rate (%) | 2% | 7% | 10% | 2% | 2% |
| Storage Efficiency (%) | 88% | 81% | 70% | - | 88% |
| Book Life (Yrs) | 20 | 60 | 40 | 20 | 20 |

### 5.2.2.7 Wind

Because TVA cannot take direct advantage of the tax credits and other investment incentives offered by the federal government to encourage wind power development, it has been more financially advantageous to acquire wind power resources through PPAs. This approach allows TVA to include wind as a resource option in the IRP. The purchase of wind resources as a PPA, whether produced in or imported to the TVA region, lowers the costs of these resources to TVA and its customers. TVA may evaluate the option of building wind facilities in the future if investment incentives and/or future federal or state renewable mandates change.

Four wind options are included in the IRP evaluation as shown in Table 5-9. The Midcontinent Independent System Operator (MISO), the Southwest Power Pool (SPP) and the In-Valley options represent various wind resources in different regional transmission areas. The High Voltage Direct Current (HVDC) option would use a direct current (DC) bulk transmission system. The HVDC transmission system would reduce power losses that are typical of the more common alternating current (AC) transmission systems. The HVDC option would require a third-party to permit and build a new transmission line, driving a later availability date than the other options.

Wind resources are energy- and capacity-limited resources. For this reason, TVA uses an energy production profile to dispatch wind energy rather than price. The method used for wind resources is somewhat similar to hydro resources except that an hourly generation schedule (not a monthly amount) is pre-loaded into the capacity expansion model. TVA also applies a capacity credit since the total nameplate capacity of a wind turbine cannot be expected at the time of the system peak. To determine the capacity credit, TVA used historical data to estimate the typical wind power output at the time of the peak power demand on the TVA system. This resulted in a 14 percent capacity credit, meaning that 14 percent of nameplate capacity is expected to be available at the system summer peak. This reduced capacity is considered the summer net dependable capacity. Appendix A includes a more detailed discussion about the determination of the data assumptions for the modeling of the wind options included in this IRP.

**Table 5-9: Wind Expansion Options**

| Unit Characteristics | MISO | SPP | In Valley | HVDC |
|---|---|---|---|---|
| Nameplate Capacity (MW) | 200 | 200 | 120 | 200 |
| Summer Net Dependable Capacity (MW) | 62 | 62 | 37 | 62 |
| Unit Availability (Yr) | 2023 | 2023 | 2023 | 2023 |
| Annual Outage Rate (%) | 4% | 4% | 4% | 4% |
| Book Life (Yrs) | 20 | 20 | 20 | 20 |

### 5.2.2.8 Solar

Similar to new wind generation, TVA cannot take direct advantage of the current investment incentives offered to promote solar power development, making it more financially advantageous to acquire solar power resources through PPAs. TVA may evaluate the option of building solar facilities in the future if investment incentives and/or federal or state renewable mandates change.

Five solar options are included in the IRP evaluation as shown in Table 5-10. All capacities are stated in AC terms. The utility tracking option is a single-axis tracker that allows the solar panels to follow the sun. The utility fixed option represents ground mounted fixed-axis/fixed-tilt solar installations. Distributed solar options are offered at large commercial, small commercial, and residential scales. Rather than being selectable, various levels of distributed solar adoption are included to represent consumer response to incentive levels applicable in each strategy, as described in Appendix F.

Like wind resources, solar resources are energy-limited and therefore dispatched in the model using an hourly energy production profile to ensure that solar generation is not utilized by the model when the sun is not available. Solar resources also are similar to the capacity-limited wind resources where the availability of the unit at the time of the TVA system peak is less than the full nameplate capacity. TVA applied a 68 percent capacity credit for the utility tracking unit and a 50 percent capacity credit for the fixed axis options. The unit availability date was rounded to the first full year. More details about the assumptions used in the development of the unit characteristics for these solar options can be found in Appendix A.

**Table 5-10: Solar Expansion Options**

| Unit Characteristics | Utility tracking | Utility fixed | Commercial small | Commercial large | Residential |
|---|---|---|---|---|---|
| Nameplate Capacity (MW) | 50 | 25 | 0.2 | 1 | 0.006 |
| Summer Net Dependable Capacity (MW) | 34 | 13 | 0.1 | 0.5 | 0.003 |
| Unit Availability (Yr) | 2023 | 2023 | 2023 | 2023 | 2023 |
| Annual Outage Rate (%) | - | - | - | - | - |
| Book Life (Yrs) | 30 | 30 | 30 | 30 | 30 |

### 5.2.2.9 Biomass

Two biomass options are included in the IRP evaluation as shown in Table 5-11: a new direct combustion biomass facility and a repower option, which is the conversion of existing coal-fired units to biomass-fired units. Because biomass co-firing is considered a fuel switch opportunity, it was not included as a capacity expansion option.

**Table 5-11: Biomass Expansion Options**

| Unit Characteristics | Direct Combustion | Repower |
|---|---|---|
| Summer Net Dependable Capacity (MW) | 115 | 124 |
| Summer Full Load Heat Rate (Btu/kWh) | 17,000 | 18,000 |
| Unit Availability (Yr) | 2024 | 2023 |
| Annual Outage Rate (%) | 14% | 12% |
| Book Life (Yrs) | 30 | 20 |

### 5.2.2.10 Demand Response

Demand response programs enable participating customers to reduce their power costs by allowing TVA to limit their power during peak demand times. These programs were modeled in the 2019 IRP, as shown in Table 5-12, based on unit characteristics similar to those used for natural gas CTs. Demand response programs are operated much like CTs, or peaking units, and focus on reduction of peak demand. However, the terms of the demand response customer contracts are shorter than the expected book life of a CT unit. In all strategies, TVA assumed that current interruptible pricing products and third-party aggregation of small commercial and industrial demand response will continue with current program size limitations at the carrying cost of a CT. Also included are residential demand response expansion options for space conditioning and water heating, available beginning in 2020.

**Table 5-12: DR Expansion Options**

| Unit Characteristics | Res 1 | Res 2 |
|---|---|---|
| Summer Capacity (MW) | 36 | 4 |
| Winter Capacity (MW) | 82 | 10 |
| Unit Availability (Yr) | 2020 | 2020 |
| Book Life (Yrs) | 8 | 8 |

### 5.2.2.11 Energy Efficiency

The 2019 IRP builds on the innovative modeling approach used in the 2015 IRP to evaluate EE as a supply-side resource, with characteristics and costs structured similarly to conventional generating resources or power plants. More details about this modeling approach can be found in Appendix D.

This IRP includes EE programs for residential (Res), commercial (Com) and industrial (Ind) sectors as shown in Table 5-13. Each was divided into tiers, representing distinct price points. The 2019 IRP includes low-income residential EE programs, which are designed to facilitate EE improvements for those least able to afford them. The costs for these programs vary by strategy, but are enforced as required resources at the incentive level dictated by the strategy goals. For all programs, all tiers are available beginning in 2020. These programs are energy limited, similar to hydro, wind and solar units, and use annual hourly production profiles.

**Table 5-13: EE Expansion Options**

| Unit Characteristics | Res Prog. 1 Tier 1 | Res Prog. 1 Tier 2 | Res Prog. 2 Tier 1 | Res Prog. 2 Tier 2 | Res Prog. 2 Tier 3 | Res Prog. 3 Tier 1 | Com Prog. 1 Tier 1 | Com Prog. 1 Tier 2 | Com Prog. 1 Tier 3 |
|---|---|---|---|---|---|---|---|---|---|
| Summer Capacity (MW) | 2 | 3 | 1 | 3 | 6 | 0 | 1 | 24 | 36 |
| Winter Capacity (MW) | 3 | 4 | 2 | 4 | 8 | 3 | 0 | 18 | 27 |
| Unit Availability (Yr) | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 |
| Book Life (Yrs) | 6 | 6 | 15 | 15 | 15 | 6 | 13 | 13 | 13 |

| Unit Characteristics | Ind Prog. 1 Tier 1 | Ind Prog. 1 Tier 2 | Ind Prog. 1 Tier 3 |
|---|---|---|---|
| Summer Capacity (MW) | 1 | 11 | 23 |
| Winter Capacity (MW) | 1 | 15 | 31 |
| Unit Availability (Yr) | 2020 | 2020 | 2020 |
| Book Life (Yrs) | 11 | 11 | 11 |

**Table 5-13: EE Expansion Options (con't)**

| Unit Characteristics | Low Income Low | Low Income Mid | Low Income High |
|---|---|---|---|
| Summer Capacity (MW) | 0.49 | 2.06 | 4.60 |
| Winter Capacity (MW) | 0.79 | 3.29 | 7.37 |
| Unit Availability (Yr) | 2020 | 2020 | 2020 |
| Book Life (Yrs) | 14 | 14 | 14 |

### 5.2.2.12 Electrification

Electrification is the increased adoption of electric end-use technologies displacing other commercial energy forms. Promotion of smart energy technologies with a favorable load shape should decrease carbon emissions and increase profitability for Valley businesses. While electrification is not a "resource" like the others described in this section, potential electrification offerings for the residential, commercial and industrial sectors are included as selectable options in this IRP. The residential electrification programs focus on retrofit and new construction markets, while commercial and industrial programs focus on diverse technology offerings to help shape load. These options are also offered in three tiers at distinct price points as shown in Electrification Expansion Options Table 5-14.

**Table 5-14: Electrification Expansion Options**

| Unit Characteristics | Res Prog. 1 Tier 1 | Res Prog. 1 Tier 2 | Res Prog. 1 Tier 3 | Res Prog. 2 Tier 1 | Res Prog. 2 Tier 2 | Res Prog. 2 Tier 3 | Res Prog. 3 Tier 1 | Res Prog. 3 Tier 2 | Res Prog. 3 Tier 3 |
|---|---|---|---|---|---|---|---|---|---|
| Summer Capacity (MW) | 1.2 | 1.0 | 0.8 | 0.2 | 0.2 | 0.3 | 0 | 0 | 0 |
| Winter Capacity (MW) | 8.6 | 6.9 | 6.0 | 0.7 | 0.6 | 0.8 | 0.06 | 0.05 | 0.08 |
| Unit Availability (Yr) | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 |
| Book Life (Yrs) | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |

| Unit Characteristics | Res Prog. 4 Tier 1 | Res Prog. 4 Tier 2 | Res Prog. 4 Tier 3 | Com Prog. 1 Tier 1 | Com Prog. 1 Tier 2 | Com Prog. 1 Tier 3 | Ind Prog. 1 Tier 1 | Ind Prog. 1 Tier 2 | Ind Prog. 1 Tier 3 |
|---|---|---|---|---|---|---|---|---|---|
| Summer Capacity (MW) | 0.08 | 0.06 | 0.09 | 8.6 | 7.5 | 5.4 | 9.0 | 7.9 | 5.6 |
| Winter Capacity (MW) | 10.3 | 8.3 | 12.4 | 18.2 | 16.0 | 11.4 | 9.4 | 8.2 | 5.9 |
| Unit Availability (Yr) | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 |
| Book Life (Yrs) | 15 | 15 | 15 | 13 | 13 | 13 | 10 | 10 | 10 |

# 6 Resource Plan Development and Analysis

This chapter describes the process TVA used to identify a target power supply mix that was based on the analysis done in the IRP. The process involves choosing the types of resources that TVA could use to meet the future power needs of its customers, recognizing that the future is uncertain and the choices need to provide flexibility to adapt. The approach tests several options around resource choices TVA could make (called strategies) in different sets of uncertain future conditions (called scenarios). The set of resource choices selected in any one future defines how TVA would provide power to its customers under those conditions; TVA calls that set of resource choices a portfolio, and it is created by modeling a strategy in a particular scenario. These portfolios are then evaluated using key factors (called metrics) that allow TVA to capture cost, risk, environmental footprint and other aspects that should be considered when deciding the best target power supply mix.

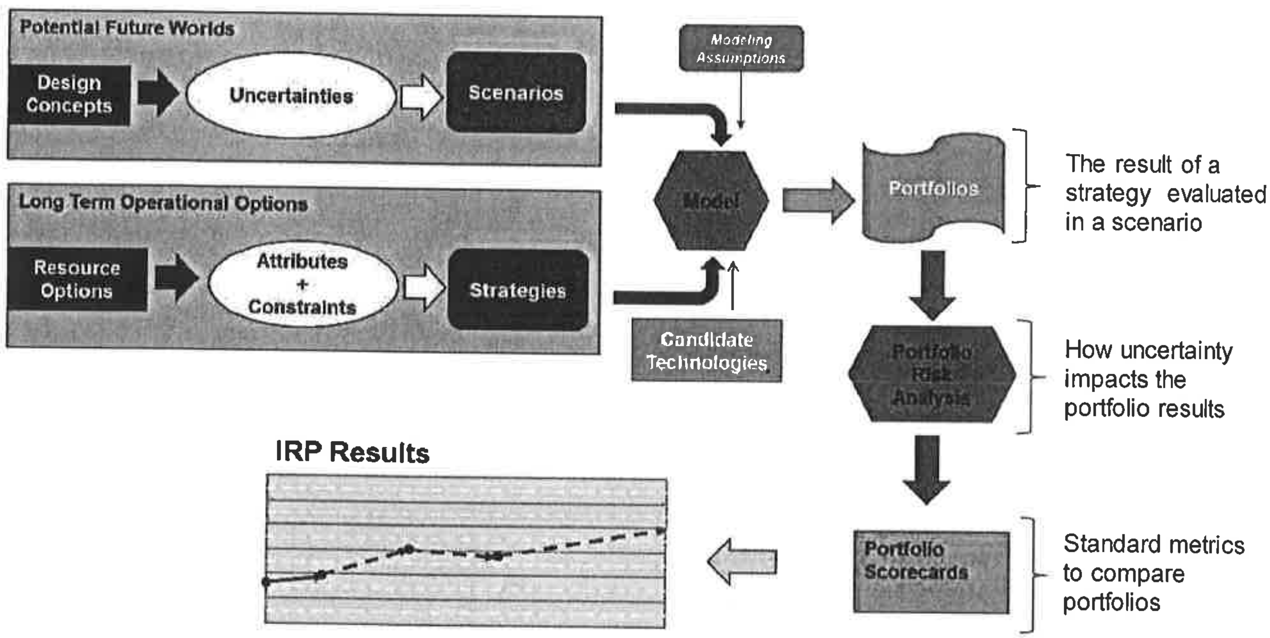



**Figure 6-1: Process Graphic Development of Scenarios and Strategies**

TVA uses a scenario planning approach in integrated resource planning, a common approach in the utility industry. Scenario planning is useful for determining how various business decisions will perform in an uncertain future. The goal is to develop a least-cost strategy that is consistent with TVA's legislatively mandated mission and also delivers rate stability to its customers over a variety of future environments.

Multiple strategies, which represent business decisions that TVA can control, are modeled against multiple scenarios, which represent uncertain futures outside of TVA's control. The intersection of a single strategy and a single scenario results in a resource portfolio. A portfolio is a 20-year capacity plan that is unique to that strategy and scenario combination.

## 6.1 Development of Scenarios

While most quantitative models used in long-range planning focus on what is statistically likely based on history, market data and projected future patterns, TVA uses scenario analysis that allows for the possibility that the future could evolve along paths not suggested solely by historical trends.

The scenarios used in the IRP analysis were developed during the scoping phase of the study in 2018. The process used to develop these scenarios is described below.

### 6.1.1 Identification of Key Uncertainties

The first step in developing scenarios was to work with the individuals on the IRP Working Group to identify key uncertainties. Uncertainties are factors that are likely to change in the future, affecting economics, demand for electricity, commodity prices, etc. While TVA can forecast future values for these uncertainties, they are difficult to predict. The goal of scenario analysis is to study broad variations in uncertainties to cover a wide range of potential futures. The 12 uncertainties, shown in Table 6-1, were used as building blocks to construct scenarios.

These uncertainties address a range of economic, financial, regulatory and legislative conditions, as well as social trends and adoption of newer technologies. The 12 uncertainties used in defining each scenario are described in Table 6-1.

**Table 6-1: Uncertainties**

| Uncertainty | Description |
|---|---|
| Electricity Demand | The customer energy requirements (in gigawatt hours) for the TVA service territory (including losses), representing the load to be served by TVA |
| Market Power Price | The hourly price of energy ($/megawatt hour) at the TVA boundary, used as a proxy for market price of power |
| Natural Gas Prices | The price ($/million BTUs) of natural gas, including transportation |
| Coal Prices | The price ($/million BTUs) of coal, including transportation |
| Solar Prices | The price ($/megawatt hour) of solar power purchase agreements delivered to TVA |
| Storage Prices | The price ($/kW) of storage new builds |
| Regulations | All regulatory and legislative actions, including applicable codes and standards, that impact the operation of electric utilities, excluding $CO_2$ regulations |
| $CO_2$ Regulation/Price | The cost of compliance with possible $CO_2$ related regulation and/or the price of cap-and-trade legislation, represented as a $/ton value |
| Distributed Generation Penetration | National trending of distributed generation resources and potential regional activity by customers or third-party developers (not TVA) |
| National Energy Efficiency (EE) Adoption | An estimate of EE measure adoption by customers nationally, recognizing the impacts of technology affordability, electricity price, and consumer interest on the willingness to adopt efficiency measures |
| Electrification | An estimate of electric end-use technology adoption displacing other commercial energy forms and providing new services |
| Economic Outlook (National/Regional) | All aspects of the regional and national economy, including general inflation, financing considerations, population growth, GDP and other factors that drive the overall economy |

### 6.1.2 Construction of Scenarios

Scenarios were constructed using combinations of the key uncertainties shown in Table 6-1 and then refined to ensure that each scenario:

- Represented a plausible, meaningful future in which TVA could find itself operating within over the 20-year study period;
- Was unique among the scenarios being considered for study;
- Placed sufficient stress on resource selection and provided a foundation for analyzing the robustness, flexibility and adaptability of each combination of supply- and demand-side options; and
- Captured relevant key stakeholder interests.

Based on overlapping characteristics, the potential scenarios were grouped into the categories of declining economy, economic growth, stringent environmental regulation, changing paradigm, and emerging technology. The IRP Working Group members provided their individual rankings on the list of scenarios that would be considered in the IRP. Based on the scoping comments, IRP Working Group member rankings and further analysis, TVA selected the five unique scenarios summarized in

Table 6-2 along with their respective attributes. In addition to these five scenarios, TVA also analyzed a Current Outlook scenario based on TVA's current assumptions about future conditions. In the modeling process, TVA considers each scenario as equally plausible.

**Table 6-2: Attributes of the Six Scenarios**

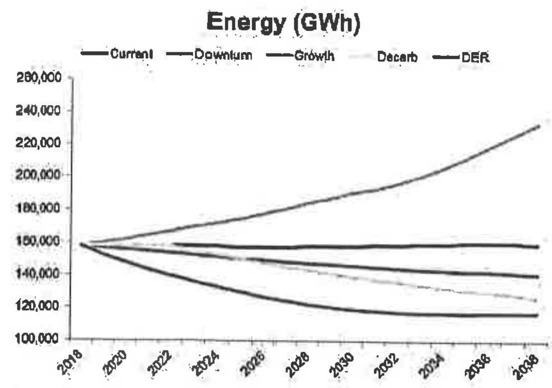
| Scenario | Description and Attributes |
|---|---|
| 1- The Current Outlook | • Economic outlook reflects slowing expected in 2020, transitioning to a long-term growth rate of 2% for TVA region GDP and 1.9% inflation<br>• Demographic changes slow customer count growth, while declining household size and increasing efficiencies drive lower energy use per customer<br>• Gas supply more than adequate to meet demand, and power prices follow seasonality of gas prices and volatility of weather |
| 2- Economic Downturn | • Prolonged, stagnant economy results in weak growth and delayed expansion of new generation<br>• Rising budget deficits and public debt constrain federal economic policy options<br>• Stringent environmental regulations are delayed due to concerns of adding further pressure to the economy<br>• Weaker demand lowers cost of new plant construction |
| 3- Valley Load Growth | • Technology-driven investment in automation and artificial intelligence raise electricity use, boosting labor productivity and economic growth while lowering inflation<br>• Rapid economic growth, driven by migration into the Valley and growth in emerging markets and developing economies, translates into higher energy sales<br>• Lower battery prices due to economies of scale drive increased electrification of transportation, magnifying growth<br>• Preference for lower emissions, DER and EE drives lower demand for emitting generation, offsetting some of the upward fuel price pressure from robust economic conditions |
| 4- Decarbonization | • Increasing climate-driven effects create strong federal push to curb greenhouse gas (GHG) emissions, increasing $CO_2$ emission penalties for the utility industry and incentives for non-emitting technologies<br>• Compliance with new rules that are stringent by global standards increases energy prices and U.S.-based industry becomes less competitive, resulting in lagging economic growth that fails to rebound to trend levels<br>• Fracking regulations never materialize, but gas demand is impacted by the $CO_2$ penalty<br>• New expansion units are necessary to replace existing $CO_2$-emitting fleet |
| 5- Rapid DER Adoption | • Growing consumer awareness of and preference for energy choice, coupled with rapid advances in energy technologies, drive high penetration of distributed generation, storage, and energy management<br>• Utilities are no longer the sole source of generation and multiple options are available to consumers<br>• Market shift results in lower loads, decreased need for supply-side generation, but increased potential impacts to transmission and distribution planning and infrastructure |
| 6- No Nuclear Extensions | • Driven by aging assets and desire for national energy security and resiliency, there is a regulatory challenge to relicensing existing and constructing new, large scale nuclear plants<br>• National energy policy drives carbon regulation or legislation and promotes small modular reactor (SMR) technology through subsidies to drive advancements and improved economics |

### 6.1.3 Determination of Key Scenario Assumptions

The final step in scenario development was to forecast key assumptions for each scenario.

Figure 6-2 shows the forecasted assumptions for TVA's energy and peak demand loads for each scenario. The Current Outlook scenario projects energy growth to be flat, as does the No Nuclear Extensions scenario. Three scenarios – Economic Downturn, De-Carbonization and Rapid DER Adoption – project declining energy forecasts, with the largest energy decline of about 1.5 percent per year in the Rapid DER Adoption scenario. The Valley Load Growth scenario projects energy growth of about 2 percent per year.

Each scenario contains unique assumptions around sector forecasts and behind-the-meter impacts that influence load shape, which drives different energy and peak growth patterns. The Current Outlook scenario projects slight peak load growth of about 0.3 percent per year, as does the No Nuclear Extensions scenario. The three scenarios that have declining energy forecasts also have declining peak load forecasts, with the largest peak decline of about -0.7 percent per year in the Rapid DER Adoption scenario. The Valley Load Growth scenario reflects peak load growth of about 1.7 percent per year.



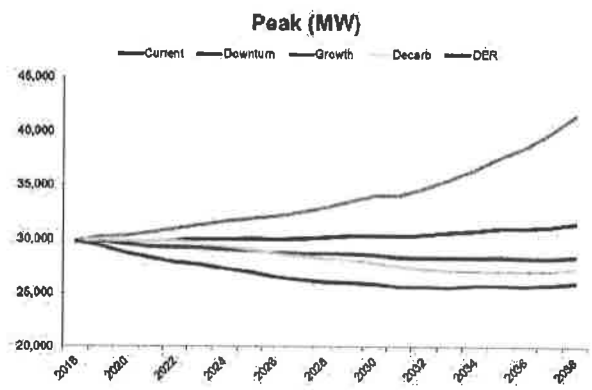




**Figure 6-2: Energy and Peak Assumptions**

Figure 6-3 shows the forecasted assumptions for natural gas prices. Gas prices are similar for the Current Outlook and No Nuclear Extensions scenarios. The Valley Load Growth and Decarbonization scenarios assume higher gas prices, with the Valley Load Growth increase happening more gradually and the Decarbonization trajectory ratcheting up as assumed regulations take effect. The Economic Downturn and Rapid DER Adoption scenarios assume lower gas prices on somewhat different trajectories.

Figure 6-4 shows the forecasted assumptions for coal prices. Steadily increasing coal prices are forecasted for all scenarios, with modest variations across the scenarios resulting from projected movements in real coal prices and inflation.

# Chapter 6: Resource Plan Development and Analysis

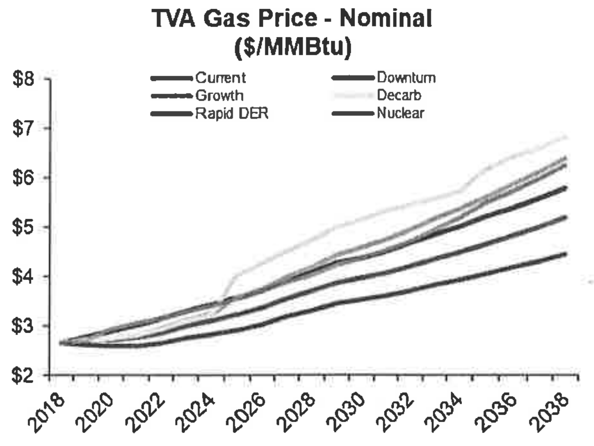



**Figure 6-3: Gas Price Assumptions**

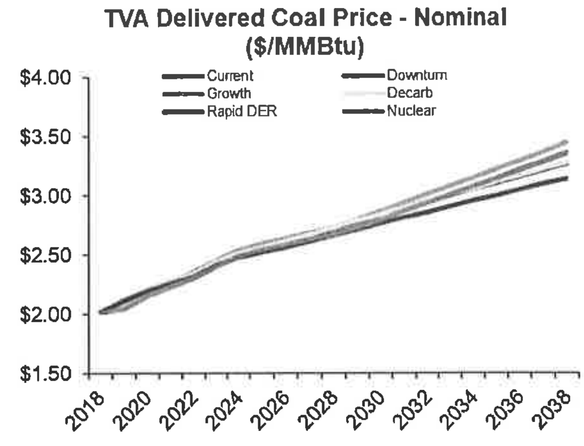
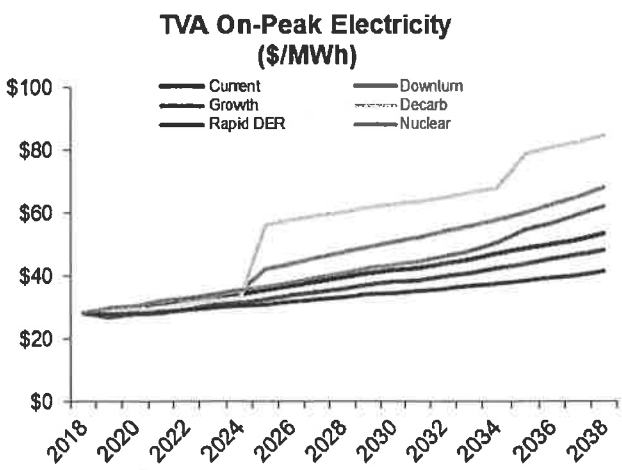



**Figure 6-4: Coal Price Assumptions**

Figure 6-5 shows the forecast assumptions for on-peak and off-peak electricity prices. Electricity prices are similar for the Current Outlook and No Nuclear Extensions scenarios. The Valley Load Growth and Decarbonization scenarios assume higher energy prices, with the Valley Load Growth increase happening more gradually and the Decarbonization trajectory ratcheting up as assumed regulations take effect. The Economic Downturn and Rapid DER Adoption scenarios assume lower electricity prices on similar trajectories.



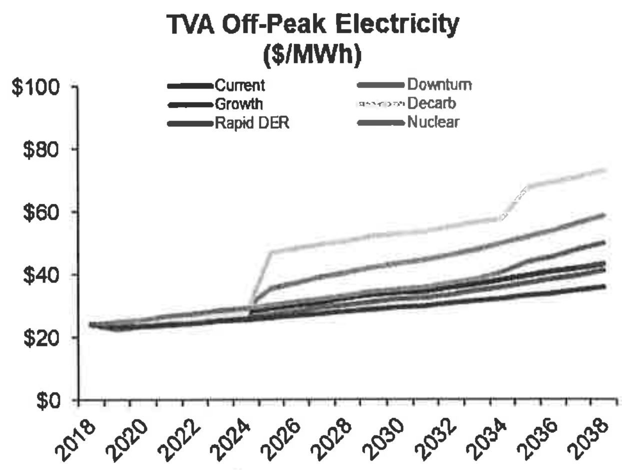




**Figure 6-5: On-peak & Off-peak Price Assumptions**

Figure 6-6 shows the forecasted assumptions for $CO_2$ prices. The Current Outlook assumes no carbon penalty, which is also the case in the Economic Downturn, Rapid DER Adoption and No Nuclear Extension scenarios. The Valley Load Growth scenario assumes a modest carbon penalty beginning in 2025 to spur faster adoption of electric vehicles. The Decarbonization scenario assumes a larger carbon penalty driven by regulations or legislative actions that takes effect in 2025 and that is ratcheted up further in 2035.

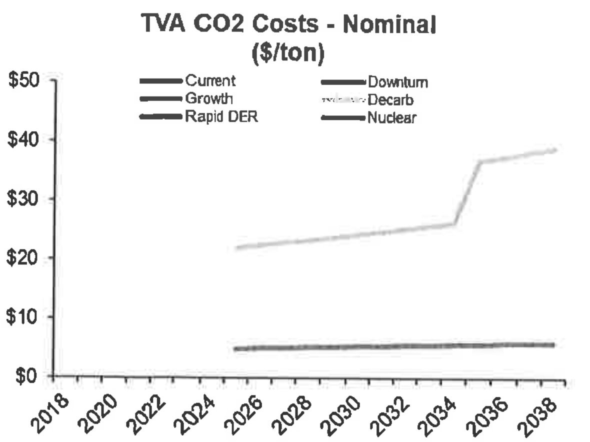



**Figure 6-6: $CO_2$ Price Assumptions**

## 6.2 Development of Strategies

After the scenarios were developed, the next step in the IRP process was to design planning strategies. Scenarios and strategies are very different. Whereas scenarios describe plausible futures and include uncertainties that TVA cannot control, strategies describe business decisions or approaches that TVA could employ.

Generally speaking, strategies promote certain resources, and in some cases also limit certain resources to support promotion of others. In IRP modeling terms, strategies that constrain how resources are selected may not be fully optimized nor produce plans that have the lowest possible financial cost. When a resource is promoted, the cost of the resource is lowered for model selection within a particular strategy. The full cost (resource and incentive) will be captured in the financial metrics. Several strategies evaluated in this IRP explore the promotion of distributed resources, and the costs of promoting adoption of those resources is shared between TVA and the DER participants. These shared costs will be analyzed further using metrics. The process used to develop strategies is described below.

### 6.2.1 Identification of Key Strategy Components

The first step in developing strategies was to identify the key components, or attributes, to be included in each strategy. Ten distinct attributes were identified using input from individuals on the IRP Working Group and comments received during the public scoping period. These attributes are described in Table 6-3.

**Table 6-3: Key Planning Strategy Attributes**

| Attributes | Description |
|---|---|
| Existing Nuclear | Constraints related to the existing nuclear fleet; EPUs are considered part of existing nuclear |
| Nuclear Additions | Limitations on technologies and timing related to the addition of new nuclear capacity; A/P 1000s and SMRs are considered in this category |
| Existing Coal | Constraints related to the existing coal fleet |
| New Coal | Limitations on technology and timing on new coal-fired plants; includes CCS on conventional coal plus IGCC technology |

| Attributes | Description |
|---|---|
| Gas Additions | Limitations on technologies and timing related to the expansion options fueled by natural gas (CT, CC) |
| Energy Efficiency | Considers energy efficiency programs that are offered by TVA and/or LPCs (excludes impacts from naturally occurring efficiency/conservation) |
| Demand Response | Considers demand response programs that are offered by TVA and/or LPCs |
| Renewables (Utility Scale) | Limitations on technologies and timing of renewable resources; considers options that would be pursued by TVA or in collaboration with LPCs |
| Storage (Utility Scale) | Limitations on technologies and timing of storage resources; considers utility scale storage options varying in size or storage capacity |
| Distributed Generation/Storage | Includes customer-driven resource options or third party projects that are distributed in nature |

#### 6.2.1.1 Development of Strategies Using Attributes

TVA combined these 10 attributes to initially create seven strategies for consideration by the IRP Working Group. After review of the scoping comments, suggestions from members of the IRP Working Group, and further analysis, TVA selected five distinct strategies. Table 6-4 lists the five strategies and their key characteristics.

**Table 6-4: Key Characteristics of the Planning Strategies**

| Strategies | Description and Attributes |
|---|---|
| A- Base Case | • Planning Reserve margins for summer and winter peak seasons are applied, targeting an industry best-practice level of reliability (applies in all strategies)<br>• No specific resource types are promoted beyond continuation of existing programs as currently forecasted. |
| B- Promote DER | • DER is incented to achieve higher end of long-term penetration levels<br>• New coal is excluded, and all other technologies are available while EE, demand response, distributed generation and storage are promoted<br>• Programs targeting low-income customers will be part of EE promotion |

| Strategies | Description and Attributes |
|---|---|
| C- Promote Resiliency | • Small, agile capacity is incented to maximize flexibility and promote ability to respond to short-term disruptions on the power system<br>• All technologies are available while small modular reactors (SMRs) and small gas additions (aeroderivative turbines, reciprocating engines), demand response, storage and distributed generation are promoted<br>• Combinations of storage and distributed generation could be installed as microgrids<br>• Flexible loads and DERs are aggregated to provide synthetic reserves to the grid to promote resiliency |
| D- Promote Efficient Load Shape | • Targeted electrification and demand and energy management are incented to minimize peaks and troughs and promote an efficient load shape<br>• All technologies are available but those that minimize load swings, including EE, DR and storage, are promoted<br>• Programs targeting low-income customers will be a part of EE promotion |
| E- Promote Renewables | • Renewables at all scales are incented to meet growing prospective or existing customer demands for renewable energy<br>• New coal is excluded, and all other technologies are available while renewables are promoted |

Strategy attributes were used in the modeling in several different ways. The Base Case represents least-cost planning with no specific resources promoted and reflects decisions made to date by the TVA Board of Directors. The remaining strategies provide incentives to promote adoption of certain resources, with consideration of market potential, pace of adoption and reserve margin. Resources that were promoted generally received a modeled incentive that improved economics for adoption or selection. In some cases, a resource category may be limited, such as new coal being excluded in the Promote DER and Promote Renewables strategies. Others have temporal restrictions, such as allowing retirements to take effect in a certain year when transmission work to allow plant separation could be completed.

#### 6.2.1.2 Definition of Strategies

After defining each strategy's key characteristics, incentive levels were determined to achieve the objectives of the strategy as shown in Figure 6-7. The Strategy Design Matrix provided the roadmap for how resource promotions were applied in capacity planning. Further information on strategy design can be found in Appendix F.

| Strategy | Distributed Resources & Electrification | | | | | | Utility Scale Resources | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Distributed Solar | Distributed Storage | Combined Heat & Power | Energy Efficiency | Demand Response | Beneficial Electrification | Solar | Wind | Biomass & Biogas | Storage | Aero CTs & Recip Engines | Small Modular Reactors |
| Base Case | Base | Base | Base | Base | Base | Base | Base | Base | Base | Base | Base | Base |
| Promote DER | High | Moderate | High | Moderate | Moderate | Base | Base | Base | Base | Base | Base | Base |
| Promote Resiliency | Moderate | High | Moderate | Base | Moderate | Base | Base | Base | Base | Moderate | Moderate | Moderate |
| Promote Efficient Load Shape | Base | Moderate | Base | High | High | Moderate | Base | Base | Base | High | Base | Base |
| Promote Renewables | Moderate | Moderate | Base | Base | Base | Base | Moderate | Moderate | Moderate | Moderate | Base | Base |

**Figure 6-7: Strategy Design Matrix**

## 6.3 Resource Portfolio Optimization Modeling

The development of resource portfolios was a two-step process. First, an optimized portfolio, or capacity plan, was generated, followed by a detailed financial analysis. This process was repeated for each strategy/scenario combination and for additional sensitivity runs. Sensitivity runs change one variable in a strategy, such as the level of promotion for a certain resource, to lend insight to the impact of a specific input.

### 6.3.1 Development of Optimized Capacity Expansion Plans

TVA uses a capacity optimization model called System Optimizer.[1] This model employs an optimization technique where an "objective function" is minimized subject to a number of constraints.

Energy resources were selected by adding or subtracting assets based on minimizing the present value of revenue requirements (PVRR). PVRR represents the cumulative present value of total revenue requirements for the study period based on an 8 percent discount rate. In other words, PVRR is the present day value of all future costs for the study period, discounted to reflect the time value of money and other factors such as investment risk.

In addition, the following constraints were applied in the optimization runs:

- Balance of supply and demand
- Energy balance
- Reserve margin
- Generation and transmission operating limits
- Fuel purchase and utilization limits
- Environmental stewardship
- Distributed generation/storage adoption.

In order to promote certain resources within a strategy, incentive levels for distributed generation and storage resources were developed to increase adoption in each strategy. These resulting adoption levels were modeled as constraints prior to optimizing the balance of the portfolio.

The System Optimizer model uses a simplified dispatch methodology to compute production costs and a "representative hours" approach in which average generation and load values in each representative period within a week are scaled up appropriately to span all hours of the week and days of the months. The least-cost path (based on lowest PVRR) from all feasible states in the study period is identified as the optimized capacity plan.

[1] System Optimizer is an industry standard software model developed by ABB.

### 6.3.2 Financial Analysis

Next, each capacity plan was evaluated using an hourly production costing methodology, which calculated detailed production costs of each plan, including fuel and other variable operating costs. These detailed cost simulations provided total strategy costs and financial metrics that were used in the strategy assessment process.

This analysis was accomplished using a strategic planning software tool called MIDAS[2]. MIDAS uses a chronological production costing approach coupled with financial planning data to assess plan cost, system rate impacts and financial risk. It uses a Monte Carlo analysis,[3] which is a sophisticated analytical technique that allows for a better understanding of portfolio performance by testing the variability of key assumptions and expressing portfolio results as a range around an expected case.

The total cost for each resource plan (PVRR) was calculated taking into account additional considerations, including the cash flows associated with financing. The model generated multiple combinations of the key assumptions for each year of the study period and computed the costs of each combination. Capital costs for supply-side options were amortized for investment recovery using a real economic carrying cost method that accounted for unequal useful lives of generating assets.

In addition to computation of the total plan cost (PVRR) over the full 20-year study period, a system average cost metric was calculated. This metric provides an alternative view of the revenue requirements for the study period expressed per MWh. It is not intended as a forecast of wholesale or retail rates over the study period. Rather, it was developed to gauge the potential rate impact associated with a given portfolio and provides an indication of relative rate pressure across the strategies being studied. Reviewing this metric in combination with PVRR and the financial risk measures provides a clearer picture of the cost/risk balance for each resource plan.

### 6.3.3 Uncertainty/Risk Analysis

While scenarios explore step changes in possible futures, stochastic analysis evaluates risk of uncertainty around key planning assumptions for each portfolio. Stochastic analysis of production cost and financials bounds the uncertainty and identifies the risk exposure that is inherent in long-range power supply planning, because the fundamental forecasts used in those studies are inevitably wrong. Variability will result due to supply/demand disruptions, weather, market conditions, technology improvements and economic cycles. A Monte Carlo simulation allows for a better understanding of the richness of possible futures, as well as their likelihoods, so that plans can be made proactively as opposed to reactively. A stochastic model is used to estimate probability distributions of potential outcomes by allowing for simultaneous random-walking variation in many inputs over time.

At TVA, a representative Monte Carlo distribution using Latin hypercube sampling (efficient method for generating probability distributions) comprised of 120 stochastic iterations is developed for each of the scenario/strategy combinations to more fully assess the likely plan costs, generation, and performance for each portfolio. To illustrate the iterations, Figure 6-8 shows a trade-off graph comparing PVRR versus $CO_2$ intensity for each iteration of a portfolio as well as the expected value, or average, and the 5th percentile and the 95th percentile, or P(5) and P(95), respectively.

A sample stochastic result which compares revenue requirements of two hypothetical portfolios is shown in Figure 6-9. This example illustrates the range of possible results of costs for each portfolio from the P(5) to P(95). The point where the color of the bars changes represents the expected cost for that portfolio.

[2] MIDAS is also an ABB product.

[3] Monte Carlo analysis is also referred to as stochastic analysis.

# Chapter 6: Resource Plan Development and Analysis

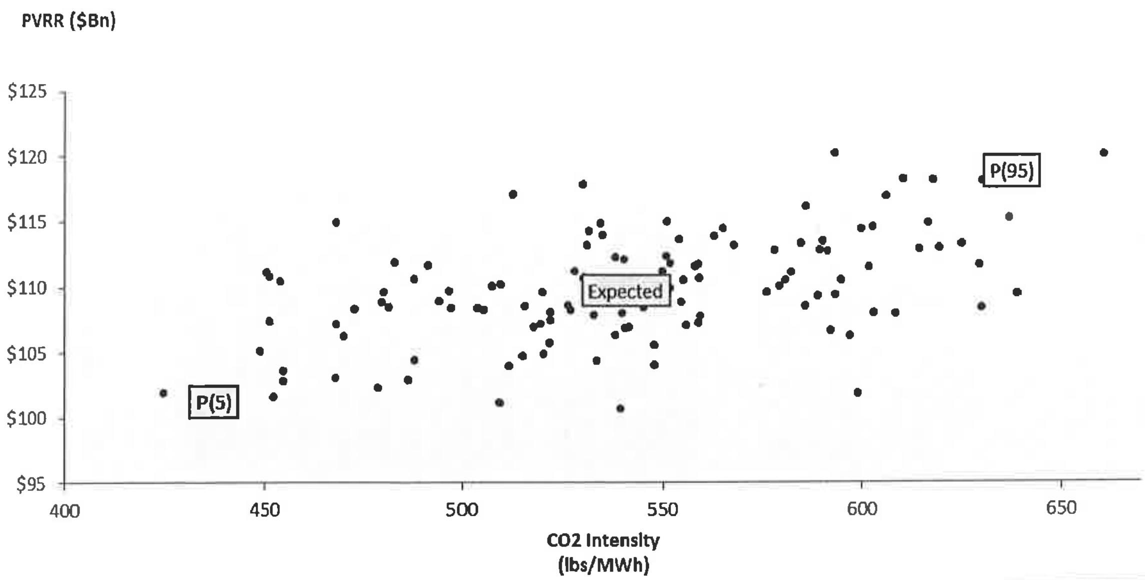



**Figure 6-8: Sample Stochastic Result with Trade-off between Present Value of Revenue Requirements and $CO_2$ Intensity**

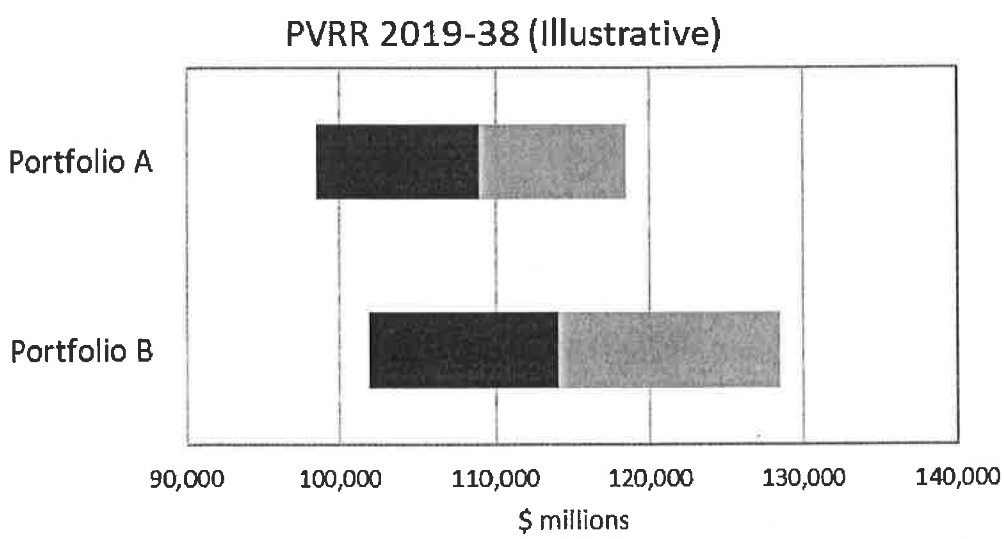



**Figure 6-9: Sample Stochastic Result for Present Value of Revenue Requirements**

Cost and risk metrics shown later in this report are calculated from the distribution of stochastic iterations. The cost and metrics are primarily the expected values while the risk metrics are functions of the P(5), P(95), and the expected value. The MIDAS tool allows TVA to explicitly consider uncertainty and risk exposure in the evaluation of the planning strategies. This analysis is based on applying probability distributions around the key variables used to frame the scenarios and define assumptions used in the strategies.

The Monte Carlo analysis in MIDAS includes 16 key variables:

- Commodity prices: natural gas, coal, oil, $CO_2$ allowances, electricity price[4]
- Financial parameters: interest rates, capital costs, operation and maintenance costs
- Availability: hydro, coal, gas, nuclear, solar, and wind
- Net sales forecast uncertainty: peak and energy, (includes demand, EE, electrification, behind-the-meter solar, and CHP)

The fundamental (expected value) forecasts for these key variables differ across the six scenarios and, as a result, the uncertainty ranges (stochastic envelope) are also different. The evaluation of the uncertainty around the performance of the strategies considers both the variation across the scenarios (different plausible futures) and the probability distribution around the expected forecasts represented by the stochastic envelope. As an example, Figure 6-10 shows these different uncertainty ranges around the TVA peak load forecast.

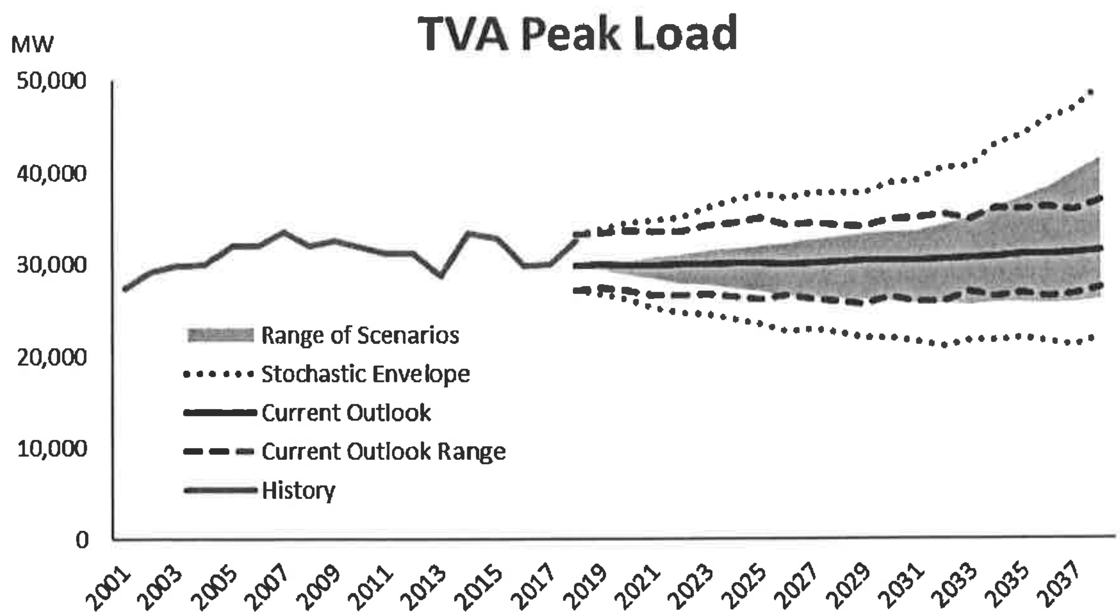



**Figure 6-10: Example Uncertainty Ranges**

Figure 6-10 shows the range of variation in the expected forecast of peak demand across all six scenarios (represented by the blue shaded area). For orientation, the Current Outlook scenario's fundamental forecast and its associated uncertainty range is shown in the black solid and dotted lines. The stochastic envelope, representing the uncertainty ranges from all six scenarios, is shown as the blue dotted line and bounds the uncertainty range evaluated in MIDAS. Each of the 16 key variables has a set of scenario ranges and stochastic envelopes that ensure a more dynamic assessment of the variability in the performance of each planning strategy.

## 6.4 Portfolio Analysis and Scorecard Development Process

Modeling multiple strategies within multiple scenarios resulted in a large number of portfolios. So, initially, the portfolio analysis focused on common characteristics

[4] Stochastic electricity price was derived fundamentally in MIDAS using stochastic variables as inputs.

that strategies exhibited over multiple scenarios rather than on specific outcomes in individual portfolios. Strategies that behaved in a similar manner in most scenarios were considered to be "robust" – i.e., more flexible, less risky over the long-term and able to lessen the impacts of uncertainty. Conversely, strategies that behaved differently or poorly in most scenarios were considered more risky with a higher probability for future regret.

The first step in the portfolio evaluation process was to develop a scorecard to assess and compare the performance of strategies in each scenario. The process used to develop an evaluation scorecard is described below.

### 6.4.1 Selection of Metric Categories

TVA's mission and stakeholder concerns related to resource planning were key considerations in developing a set of metrics for use in evaluating the performance of the portfolios generated in the IRP.

To achieve its overall mission of providing low-cost, reliable power to the people of the Valley, TVA focuses on four strategic imperatives, as mentioned previously in Chapter 1. These imperatives are: balancing rates and debt so that TVA maintains low power rates while living within its means; and recognizing the trade-off between optimizing the value of our asset portfolio and being responsible stewards of the Valley's environment and natural resources.

Optimizing TVA's asset portfolio is the primary purpose of integrated resource planning, but other imperatives also shape the process:

- As part of the financial analysis, a balance sheet and income statement are created for each portfolio to determine the revenue requirements to fund each resource plan.
- A coverage ratio method is used to ensure that the overall debt limit is respected in each optimization run.
- Stewardship obligations are considered in modeling of various compliance requirements, including portfolio optimization which factors in a carbon penalty and includes key environmental metrics in the assessment of each resource plan (air, water, waste and land-use impacts).

Based on TVA's strategic imperatives and feedback from stakeholders, five metric categories were selected for use in evaluating the performance of planning strategies:

- **Cost**, including both the long-range cost of the resource plan as well as a look at average system cost, which is an indicator of possible rate pressure
- **Financial Risk**, which measures the variation (uncertainty) around the cost of the resource plan by assessing a risk/benefit ratio and computing the likely amount of cost at risk using data from probability modeling
- **Environmental Stewardship**, which captures multiple measures related to the environmental footprint of the resource plans, including air emissions and water, waste and land use impacts
- **Operational Flexibility**, which measures how responsive the generation portfolio of each resource plan is by evaluating the portfolio's ability to ramp up and down to respond to changes in demand
- **Valley Economics**, which computes the macro-economic effects of the resource plans by measuring the change in real per capita income (where real references the fact that the income streams have been adjusted to remove the impacts of inflation, such that future income streams and present income streams all possess a consistent purchasing capability) and employment compared to a reference case.

### 6.4.2 Development of Metrics

After establishing the metric categories, the next step was to identify candidate metrics for each category to be used in the scorecard to assess the performance of each strategy in different scenarios.

# Chapter 6: Resource Plan Development and Analysis

Considering input from the IRP Working Group and Regional Energy Resource Council, TVA selected 14 metrics that clearly and effectively measure the performance of each portfolio as summarized in Figure 6-11.

| Category | Metric | Definition |
|---|---|---|
| Cost | PVRR ($Bn) | Total plan cost (capital and operating) expressed as the expected (stochastic) present value of revenue requirements over the 20-year study period |
| | System Average Cost ($/MWh) | Expected average system cost for the study period, computed as the levelized annual average system cost (annual revenue requirements divided by annual sales) |
| | Total Resource Cost ($Bn) | Total plan cost (capital and operating) expressed as the expected present value of revenue requirements over the study period plus participant cost net of bill savings and tax credits |
| | Risk/Benefit Ratio | Area under the plan cost distribution curve between P(95) and expected value divided by the area between expected value and P(5) based on stochastic analysis |
| | Risk Exposure ($Bn) | The point on the plan cost distribution below which the likely plan costs will fall 95% of the time based on stochastic analysis |
| Environmental Stewardship | $CO_2$ (MMTons) | Expected annual average tons of $CO_2$ emitted over the study period |
| | $CO_2$ Intensity (lbs/MWh) | Expected $CO_2$ emissions expressed as an emission intensity, computed by dividing emissions by energy generated and purchased |
| | Water Consumption (MMGallons) | Expected annual average gallons of water consumed over the study period |
| | Waste (MMTons) | Expected annual average quantity of coal ash, sludge and slag projected based on energy production in each portfolio |
| | Land Use (Acres) | Expected acreage needed for expansion units in each portfolio in 2038 |
| Operational Flexibility | Flexible Resource Coverage Ratio | The ratio of flexible capacity available to meet the maximum 3-hour ramp in demand in 2038 |
| | Flexibility Turn Down Factor | Ability of the system to serve low load periods as measured by the percent of must-run and non-dispatchable generation to sales |
| Valley [illegible] | Percent Difference in Real Per Capita Income | The change in real per capita personal income expressed as a change from a reference portfolio in each scenario |
| | Percent Difference in Employment | The change in non-farm employment expressed as a change from a reference portfolio in each scenario |

**Figure 6-11: Metrics Definitions**

# Chapter 6: Resource Plan Development and Analysis

Figure 6-12 shows the formulas used to compute the metrics.

| Category | Metric | Formula |
|---|---|---|
| Cost | PVRR ($Bn) | Present Value of Revenue Requirements over Planning Period |
| | Total Resource Cost ($Bn) | PVRR + Participant cost net of savings (bill savings, tax credits) |
| | System Average Cost ($/MWh) | NPV Rev Reqs (2019–2038) / NPV Sales (2019–2038) |
| Risk | Risk/Benefit Ratio | 95th (PVRR)–Expected (PVRR) / Expected (PVRR)–5th (PVRR) |
| | Risk Exposure ($Bn) | 95th Percentile (PVRR) |
| Environmental Stewardship | CO2 (MMTons) | Average Annual Tons of CO2 Emitted During Planning Period |
| | CO2 Intensity (lbs/MWh) | Pounds CO2 (2019–2038) / MWh Generated & Purchased (2019–2038) |
| | Water Consumption (MMGallons) | Average Annual Gallons of Water Consumed During Planning Period |
| | Waste (MMTons) | Average Annual Tons of Coal Ash and Scrubber Residue During Planning Period |
| | Land Use (Acres) | Acreage Needed for Expansion Units in Each Portfolio (2038) |
| Operational Flexibility | Flexible Resource Coverage Ratio | Flexible Capacity Available for Max 3-Hour Ramp in each Strategy (2038) / Capacity Required for Max 3-Hour Ramp in each Scenario (2038) |
| | Flexibility Turn Down Factor | "Must Run" + "Non-Dispatchable" (2038) / Sales (2038) |
| Valley Economics | Percent Difference in Real Per Capita Income | Percent Difference In Real Per Capita Personal Income Compared to the Base Case (for each scenario) |
| | Percent Difference in Employment | Percent Difference in Non-Farm Employment Compared to the Base Case |

**Figure 6-12: Metric Formulas**

The scorecard metrics selected align with TVA's mission as shown in Figure 6-13.

| IRP Scorecard Metrics | | TVA Mission: Low-Cost Reliable Power | TVA Mission: Economic Development | TVA Mission: Environmental Stewardship |
|---|---|---|---|---|
| Cost | PVRR ($Bn) | ✓ | ✓ | |
| | System Average Cost ($/MWh) | ✓ | ✓ | |
| | Total Resource Cost ($Bn) | ✓ | | |
| Risk | Risk/Benefit Ratio | ✓ | | |
| | Risk Exposure ($Bn) | ✓ | | |
| Environmental Stewardship | CO2 (MMTons) | | ✓ | ✓ |
| | CO2 Intensity (lbs/MWh) | | ✓ | ✓ |
| | Water Consumption (MMGallons) | | | ✓ |
| | Waste (MMTons) | | | ✓ |
| | Land Use (Acres) | | | ✓ |
| Operational Flexibility | Flexible Resource Coverage Ratio | ✓ | | |
| | Flexibility Turn Down Factor | ✓ | | |
| Valley Economics | Percent Difference in Real Per Capita Income | ✓ | ✓ | |
| | Percent Difference in Employment | | ✓ | |

**Figure 6-13: Scorecard Alignment Scorecard Design**

| Scorecard Metric | Scenarios | | | | | |
|---|---|---|---|---|---|---|
| | Current Outlook | Economic Downturn | Valley Load Growth | Decarbonization | Rapid DER Adoption | No Nuclear Extensions |
| PVRR ($Bn) | | | | | | |
| Total Resource Cost ($Bn) | | | | | | |
| System Average Cost ($/MWh) | | | | | | |
| Risk/Benefit Ratio | | | | | | |
| Risk Exposure ($Bn) | | | | | | |
| CO2 (MMTons) | | | | | | |
| CO2 Intensity(lbs/MWh) | | | | | | |
| Water Consumption (MMGallons) | | | | | | |
| Waste (MMTons) | | | | | | |
| Land Use (Acres) | | | | | | |
| Flexible Resource Coverage Ratio | | | | | | |
| Flexibility Turn Down Factor | | | | | | |
| Percent Difference in Real Per Capita Income | | | | | | |
| Percent Difference in Employment | | | | | | |

**Figure 6-14: Scorecard Template**

Once the metrics were selected, the strategy scorecard could be designed. Using a format similar to the 2015 IRP, the scorecard summarizes the performance of an individual planning strategy in each of the scenarios. To evaluate differences within a given scenario, all five scorecards were reviewed. Interpretation of the performance of each strategy is presented in Chapter 7.

## 6.5 Strategy Assessment Process

Finally, scorecards were populated based on an assessment of overall performance of each strategy in the five metric categories: cost, risk, environmental stewardship, operational flexibility, and Valley economics.

Each metric category was assessed individually and graphics were developed to facilitate interpretation of trends and to identify preliminary observations. Examples of key graphics include a comparison of cost and risk and a comparison of cost and $CO_2$ emissions to enable investigation of possible trade-offs. These observations guided the development of an action plan for further case analysis.

The strategy assessment graphics, along with information about observations from the IRP study and the action plan, can be found in Chapter 8.

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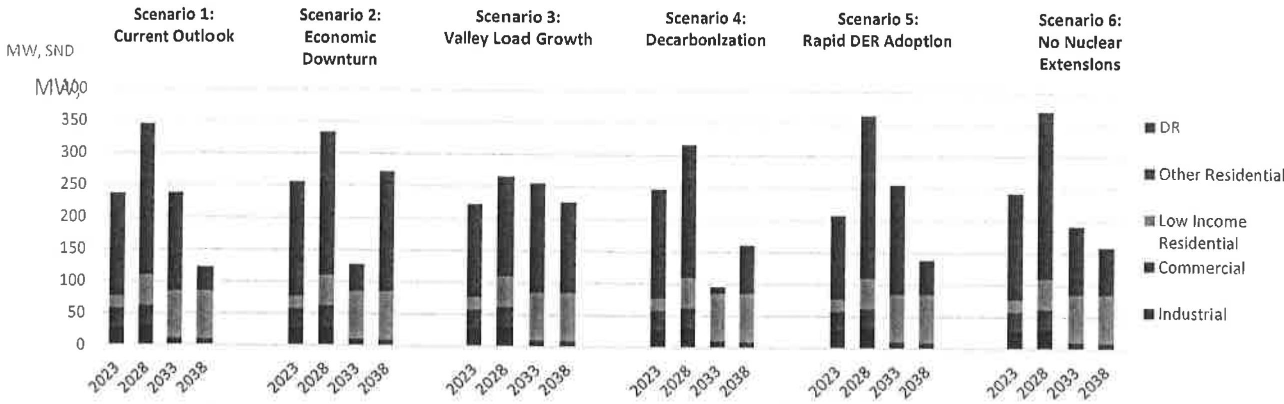



**Figure 7-10: Incremental EEDR Capacity by 2038**

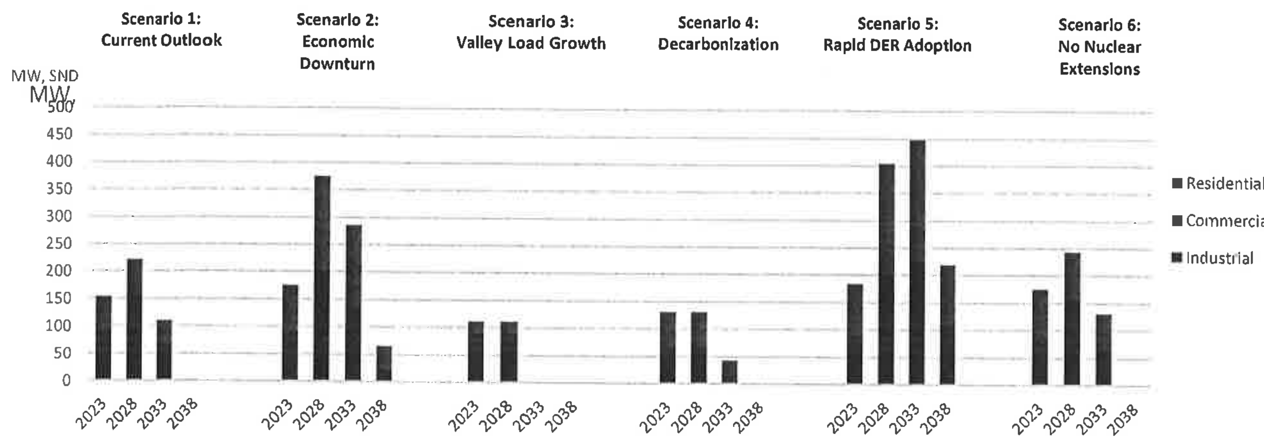



**Figure 7-11: Incremental BE Capacity by 2038**

## 7.1.10 Summaries by Strategy

**Strategy A: Base Case** is TVA's least-cost optimization plan that applies no additional incentives or targets. Resources are chosen economically to meet the reserve margin constraint for reliability.

Figure 7-12 presents the modeled capacity results for Strategy A. The capacity portfolios show the summer net dependable megawatts in 2038. The **nuclear** portfolio is the same in all scenarios, except for Scenario 6 where Browns Ferry units are retired. **Hydro** capacity is the same in all cases. **Coal** capacity is the same in all scenarios, except for Scenario 4, where carbon regulation leads to additional coal retirements. **Solar** assets are added beginning in the mid-2020 time frame, and continue to be added throughout most of the planning horizon. Including hydro, renewables account for 18 percent of the capacity portfolio on average. Natural **gas** assets increase over time, beginning with Gas CC additions that could be achieved through renewal of existing contracts, acquisitions or builds. These are augmented by Gas CT additions in Scenario 3 and 6 cases. With current cost projections and no promotion in Strategy A, no **storage** appears in any portfolios. **Energy efficiency** increases modestly in all scenarios, with impacts lessened as efficiencies from codes and standards increase. **Demand response** increases similarly across scenarios, with some differentiation due to load shape and strategic focus.

Figure 7-13 shows the energy portfolios that correspond to the capacity charts in Figure 7-12.

# Chapter 7: Study Results

**Nuclear** energy remains the same over time across the cases, with the exception of the Scenario 6 case where energy from the retired Browns Ferry units is replaced primarily with solar and gas generation. **Hydro** energy remains the same across portfolios. **Coal** generation decreases over the planning horizon as units are retired and declines further in lower load cases, especially in Scenario 4. **Solar** generation increases substantially in all cases, with the highest increases seen in Scenario 3 and 4 portfolios. Including hydro, renewables account for 20 percent of total generation on average. Natural **gas** generation varies with load and strategic focus, with the highest gas generation seen in the Scenario 3 and 6 cases. Demand response, which produces low energy volumes, has been combined with the energy efficiency into one group termed EEDR. Incremental **EEDR** contributes a small amount to the portfolio, with increasing impacts from codes and standards reflected in the load forecast without additional TVA incentives. Strategy A results in 61 percent carbon-free generation in 2038 on average.

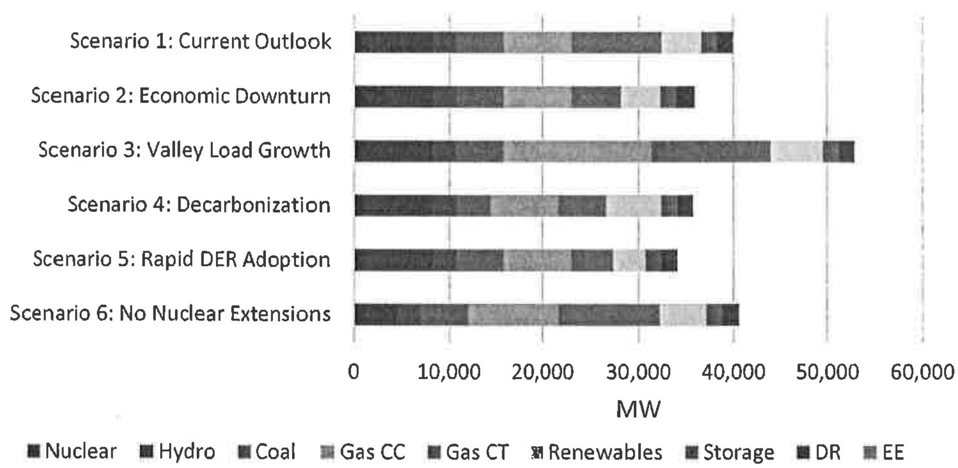



**Figure 7-12: Capacity (Summer Net Dependable Megawatts) in 2038 for Strategy A by Scenario**

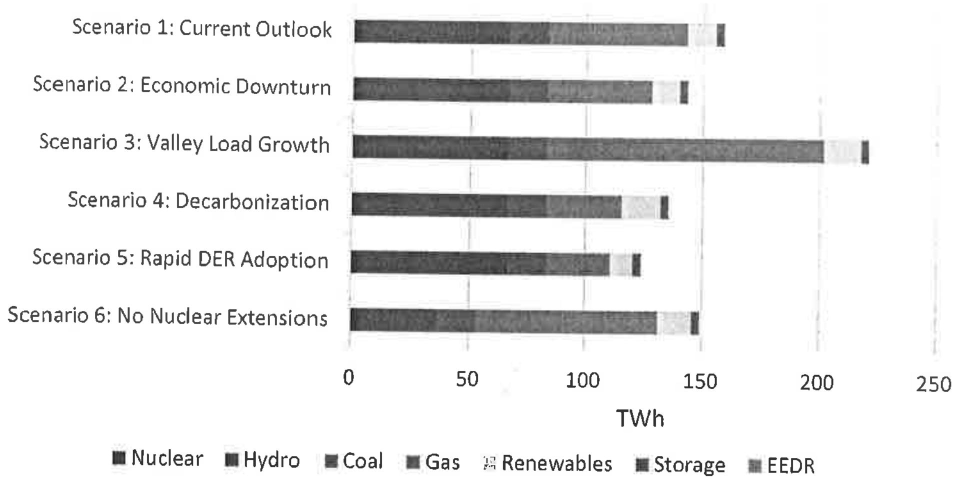



**Figure 7-13: Energy (Terawatt Hours) in 2038 for Strategy A by Scenario**

**Strategy B: Promote DER** focuses on increasing the pace of DER adoption by incenting distributed solar and storage, combined heat and power, energy efficiency and demand response. Promotions are first applied, and then the balance of the system is optimized in a least-cost manner. The approach used to model increased adoption through an incentive mechanism is discussed further in Appendix C.

Figure 7-14 shows the capacity resources added by 2038 in Strategy B across the six scenarios. The results from this strategy are very similar to Strategy A with a few notable differences. Distributed **solar** is promoted in this strategy and generally replaces a portion of lower cost utility solar. Distributed **storage** is also promoted, replacing a portion of demand response but at a higher cost. Finally, **CHP** is promoted, driving slightly lower utility-scale gas additions.

Figure 7-15 shows how the energy portfolios for Strategy B play out driven by the capacity changes and other factors in the scenarios. Including hydro, renewables account for 20 percent of total generation on average. Strategy B results in 61 percent carbon-free generation in 2038 on average, similar to Strategy A.

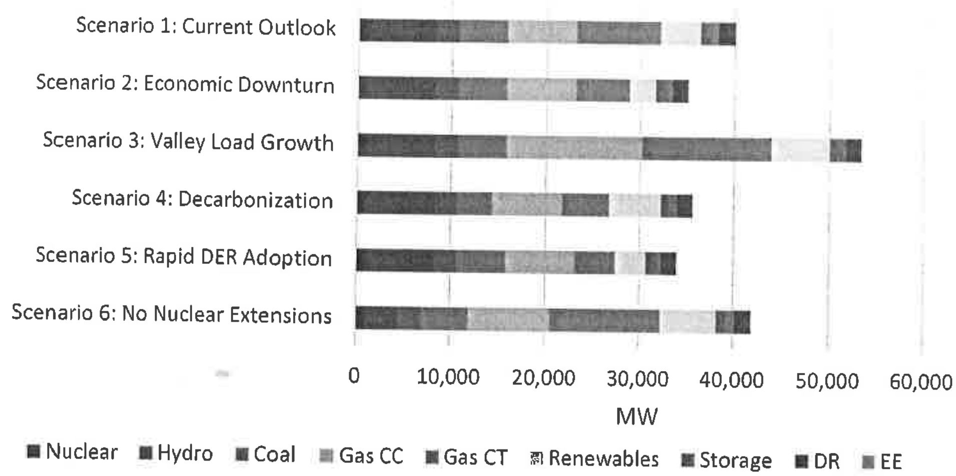



**Figure 7-14: Capacity (Summer Net Dependable Megawatts) in 2038 for Strategy B by Scenario**

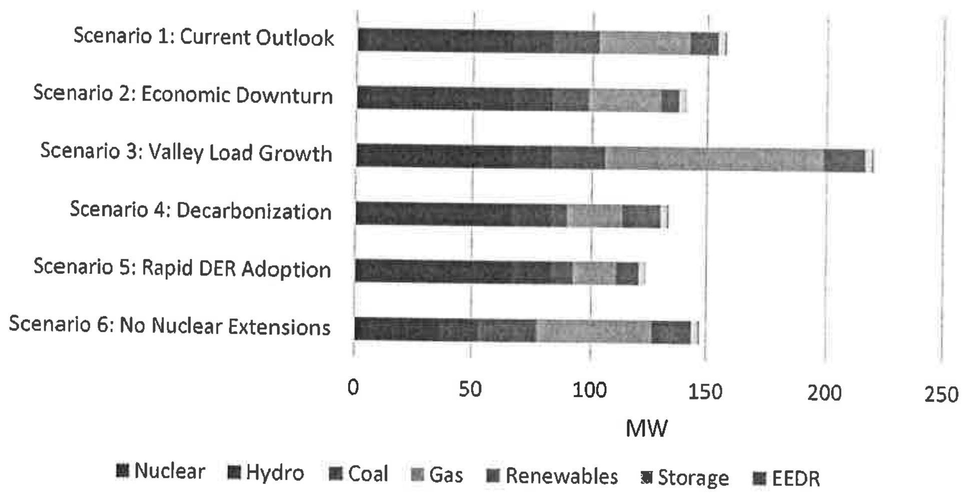



**Figure 7-15: Energy (Terawatt Hours) in 2038 for Strategy B by Scenario**

**Strategy C: Promote Resiliency** incents higher adoption of small, agile capacity to increase the operational flexibility of TVA's power system, while also improving the ability to respond locally to short-term disruptions. Promotions are first applied, and then the balance of the system is optimized in a least-cost manner. The approach used to model increased adoption through an incentive mechanism is discussed further in Appendix C.

Figure 7-16 presents the total capacity portfolios in 2038 for Strategy C. The **hydro** portfolio is the same as in Strategy A. **Nuclear** capacity is the same as in Strategy A, with the exception of Scenario 6 where 1,200 MW of SMRs are added to replace one Browns Ferry nuclear unit. **Coal** capacity is the same across all scenarios, except for Scenario 4 in which carbon regulation leads to additional coal retirements. When more coal is retired, **solar** capacity increases at both utility and distributed scales. **Storage** additions are promoted, resulting in somewhat lower **gas** capacity additions on average. **EEDR** volumes remain similar across the scenarios in this strategy.

Figure 7-17 shows the resulting energy portfolios for Strategy C driven by the capacity changes and other factors in the scenarios. Including hydro, renewables account for 22 percent of total generation on average. Strategy C results in 63 percent carbon-free generation in 2038 on average, compared to 61 percent in Strategy A.

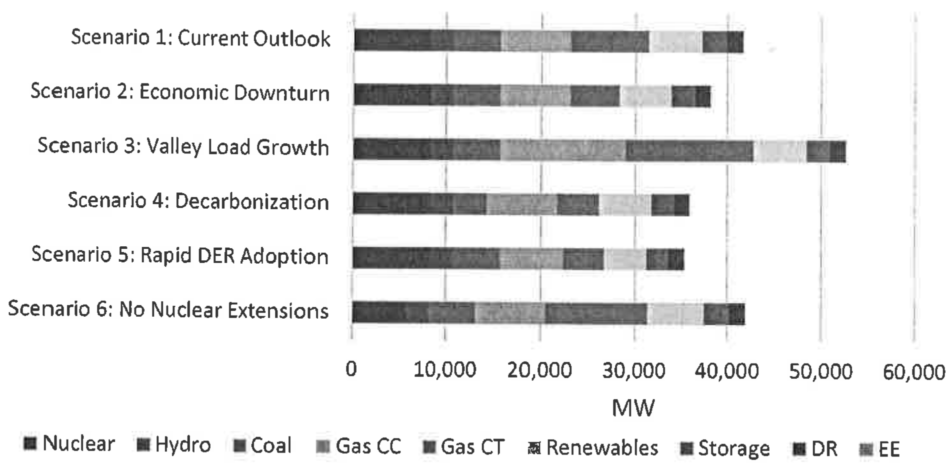



**Figure 7-16: Capacity (Summer Net Dependable Megawatts) in 2038 for Strategy C by Scenario**

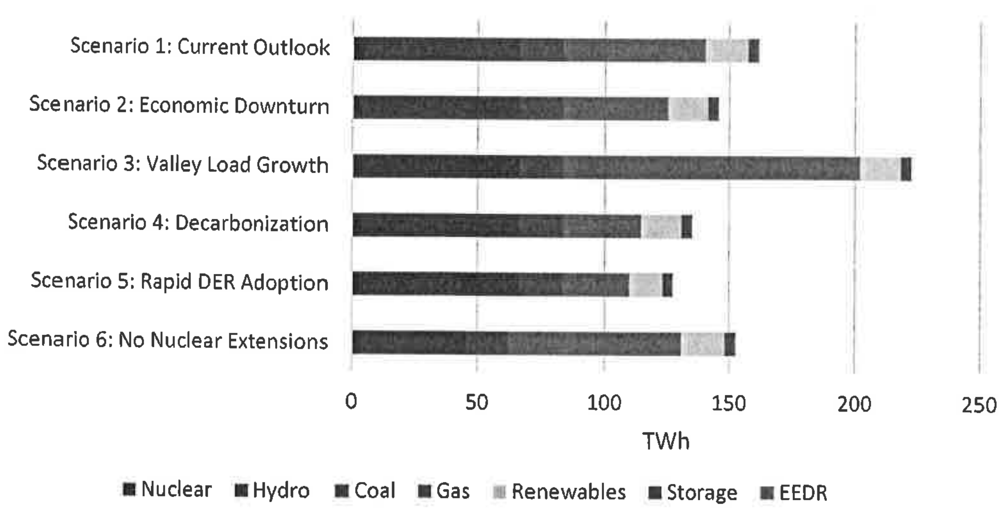



**Figure 7-17: Energy (Terawatt Hours) in 2038 for Strategy C by Scenario**

**Strategy D: Promote Efficient Load Shape** incents targeted electrification, demand response, and energy management to optimize load shape, including programs targeting low-income energy efficiency. Promotions are first applied, and then the balance of the system is optimized in a least-cost manner.

Figure 7-18 shows the capacity resources added by 2038 in Strategy D across the six scenarios. The **nuclear** and **hydro** portfolios are the same as in Strategy A. This strategy results in the highest amount of **coal** retirements on average. That capacity is replaced with a combination of solar, storage and gas additions, with a high penetration of **solar** achieved in all cases. **Storage** is promoted to the greatest degree in this strategy, resulting in the highest storage capacity overall. The storage additions drive the lowest need for gas capacity, especially CT peaking units. The highest **EE** volumes are seen in this strategy, and **DR** volumes are similar to Strategy A by 2038, as the promotion of storage meets peaking needs.

Figure 7-19 shows the corresponding energy portfolios for Strategy D driven by the capacity changes and other factors in the scenarios. Including hydro, renewables account for 22 percent of total generation on average. Strategy D results in 61 percent carbon-free generation, similar to Strategy A.

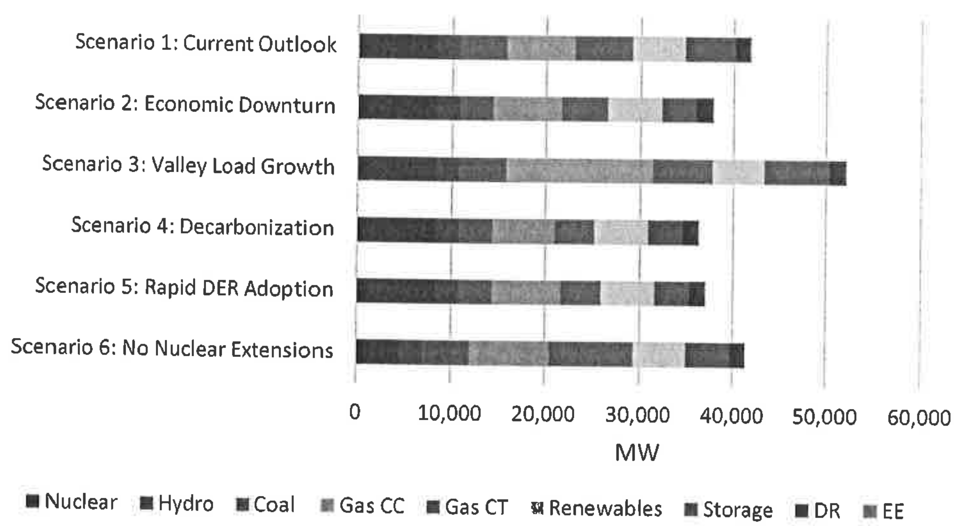



**Figure 7-18: Capacity (Summer Net Dependable Megawatts) in 2038 for Strategy D by Scenario**

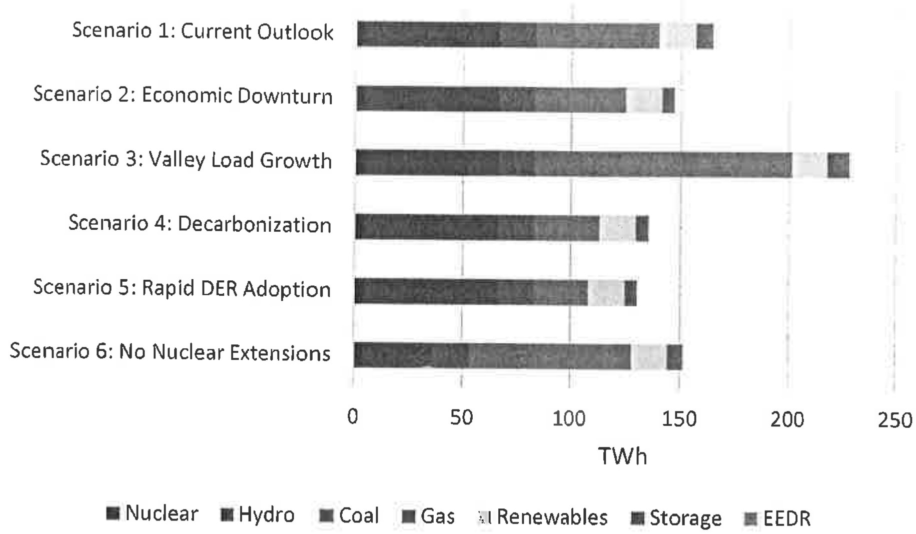



**Figure 7-19: Energy (Terawatt Hours) in 2038 for Strategy D by Scenario**

**Strategy E: Promote Renewables** incents renewables at all scales to meet growing prospective or existing customer demands for renewable energy. Promotions are first applied, and then the balance of the system is optimized in a least-cost manner. The approach used to model increased adoption through an incentive mechanism is discussed further in Appendix C.

Figure 7-20 presents the total capacity portfolios in 2038 for Strategy E. The **nuclear** and **hydro** portfolios are the same as in Strategy A. Coal capacity is the same across all scenarios, except for Scenario 4 in which carbon regulation leads to additional coal retirements. The highest levels of **solar** additions are seen in this strategy across all scenarios, averaging nearly 6,000 MW summer NDC and 9,000 MW nameplate. Including hydro, renewables account for 20 percent of the capacity portfolio on average. **Storage** is also promoted, resulting in a comparable level of storage additions as in Strategy C, and similarly reducing the need for **gas** capacity additions. **EEDR** volumes remain similar across the scenarios in this strategy, also resembling Strategy C.

Figure 7-21 shows the corresponding energy portfolios for Strategy E driven by the capacity changes and other factors in the scenarios. Including hydro, renewables account for 22 percent of total generation on average. Strategy E results in 62 percent carbon-free generation in 2038 on average, compared to 61 percent in Strategy A.

# Chapter 7: Study Results

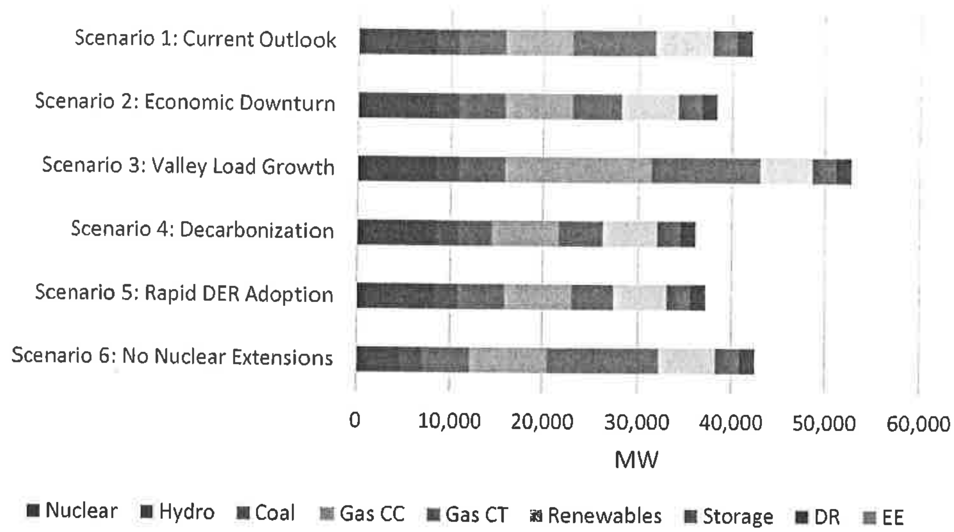



**Figure 7-20: Capacity (Summer Net Dependable Megawatts) in 2038 for Strategy E by Scenario**

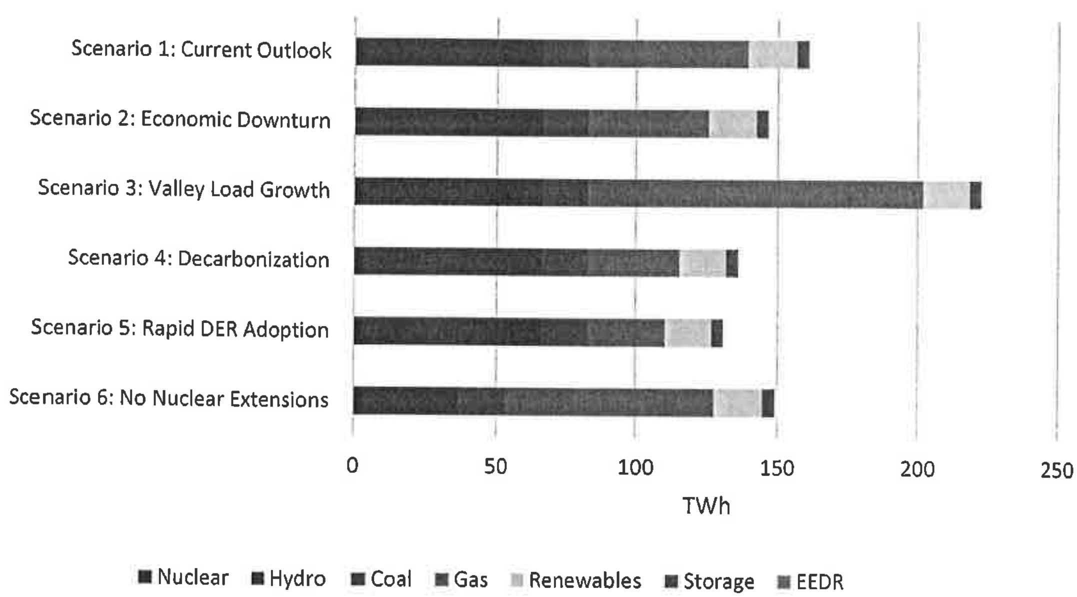



**Figure 7-21: Energy (Terawatt Hours) in 2038 for Strategy E by Scenario**

| | Strategy | 1 Current | 2 Economic Downturn | 3 Growth | 4 Decarbonization | 5 Rapid DER Adoption | 6 No Nuclear Extensions |
|---|---|---|---|---|---|---|---|
| Flexible Resource Coverage Ratio | A | 1.98 | 1.37 | 2.17 | 0.98 | 1.14 | 2.22 |
| | B | 1.97 | 1.71 | 2.11 | 0.98 | 1.14 | 2.03 |
| | C | 1.65 | 1.29 | 2.09 | 1.04 | 1.02 | 1.75 |
| | D | 1.60 | 1.39 | 1.79 | 1.15 | 1.13 | 1.83 |
| | E | 1.65 | 1.26 | 2.15 | 1.04 | 1.02 | 1.98 |
| Flexibility Turn Down Factor (2038) | A | 50% | 56% | 36% | 66% | 63% | 32% |
| | B | 50% | 53% | 36% | 66% | 63% | 34% |
| | C | 53% | 59% | 36% | 66% | 66% | 40% |
| | D | 53% | 59% | 36% | 66% | 69% | 34% |
| | E | 53% | 60% | 36% | 66% | 67% | 34% |
| Percent Difference in Real Per Capita Income (Relative to Strategy A) | A | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | B | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | C | -0.01% | 0.00% | -0.02% | 0.00% | 0.00% | -0.03% |
| | D | -0.01% | -0.02% | -0.09% | -0.02% | -0.02% | -0.01% |
| | E | 0.00% | 0.00% | -0.01% | 0.00% | -0.01% | 0.00% |
| Percent Change in Employment (Relative to Strategy A) | A | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | B | 0.01% | 0.00% | 0.00% | 0.01% | 0.10% | 0.00% |
| | C | 0.01% | 0.01% | 0.00% | 0.01% | 0.10% | 0.01% |
| | D | 0.02% | 0.01% | -0.06% | 0.01% | 0.11% | 0.00% |
| | E | 0.01% | 0.01% | 0.00% | 0.00% | 0.10% | 0.00% |

(Columns 1–6 are grouped under the header "Scenario".)

**Figure 7-27: Scorecard Metrics by Strategy and Scenario**

## 7.4 Observations from Modeling Results

Based on the results of the modeling, TVA made the following observations about incremental capacity across the portfolios.

- There is a need for new capacity in all scenarios, even in low load futures, to replace expiring or retiring capacity
- Solar expansion plays a substantial role in all futures, driven by its attractive energy value beginning in the mid-2020 time frame
- Gas, storage and demand response additions provide reliability and/or flexibility across all seasons
- No baseload resources (designed to operate around the clock) are added, except for the promotion of SMRs in one case
- Additional coal retirements occur in certain futures, especially in a carbon-constrained world
- EEDR levels are relatively similar across the portfolios, with EE opportunity decreasing as efficiency impacts from codes and standards increase over time
- In all cases, TVA will continue to provide for economic growth in the Tennessee Valley.

These observations are further explored in the assessments presented in Chapter 8.

# Chapter 8: Strategy Assessment and Next Steps

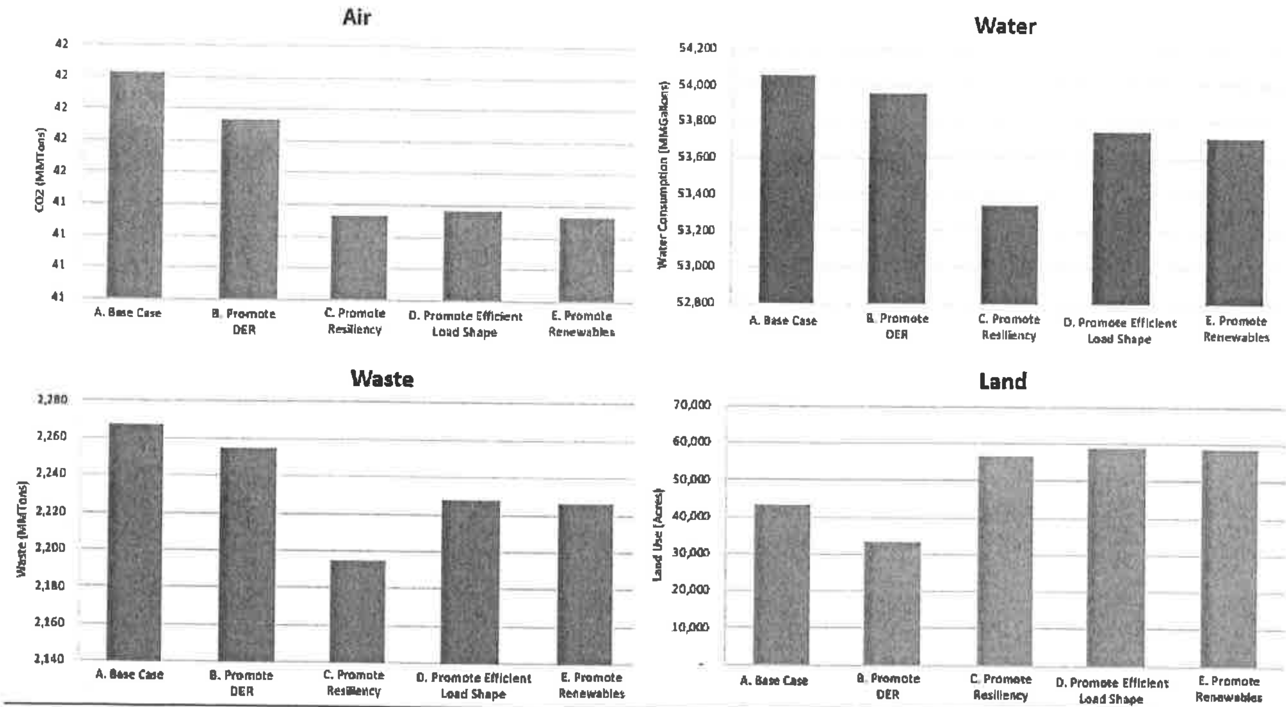



**Figure 8-8: Environmental Impacts for Scenario 1 (Current Outlook)**

All strategies show improvement in air, water and waste compared to the current resource portfolio, with Strategy C the most favorable. All strategies show increased land use compared to the current resource portfolio driven by various levels of solar expansion. Strategies that promote solar tend to have favorable environmental profiles, except for increased land use. While overall land use is higher for solar facilities on a per MW basis, the impacts to the land are generally low level and have the potential to be readily returned to the previous condition or use.

Strategy C has the lowest environmental impact with respect to air, water and waste. Strategy A has the highest environmental impact overall but low land use. The other strategies generally fall somewhere in between, except for land use where Strategy B has the lowest acreage.

Another helpful view is a comparison of $CO_2$ intensity across all 30 portfolios. As shown in Figure 8-9, the scenario has the greatest influence on $CO_2$ intensity, with variations across strategies as described in the Current Outlook example. Range of stochastic results are included in Appendix I.

Figure 8-10 shows trade-offs between system average cost and $CO_2$ intensity across all portfolios. The scenario that materializes will drive $CO_2$ intensity at relatively similar system average cost, regardless of the strategy.

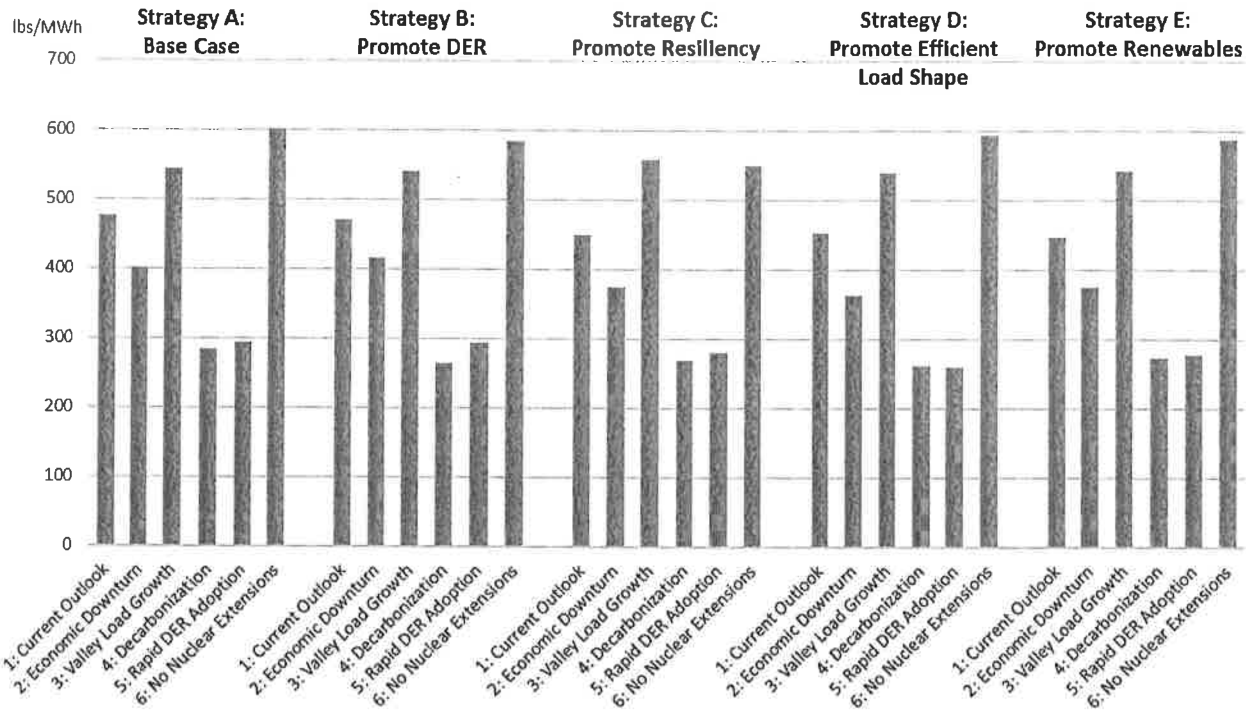



**Figure 8-9: Portfolio $CO_2$ Intensity**

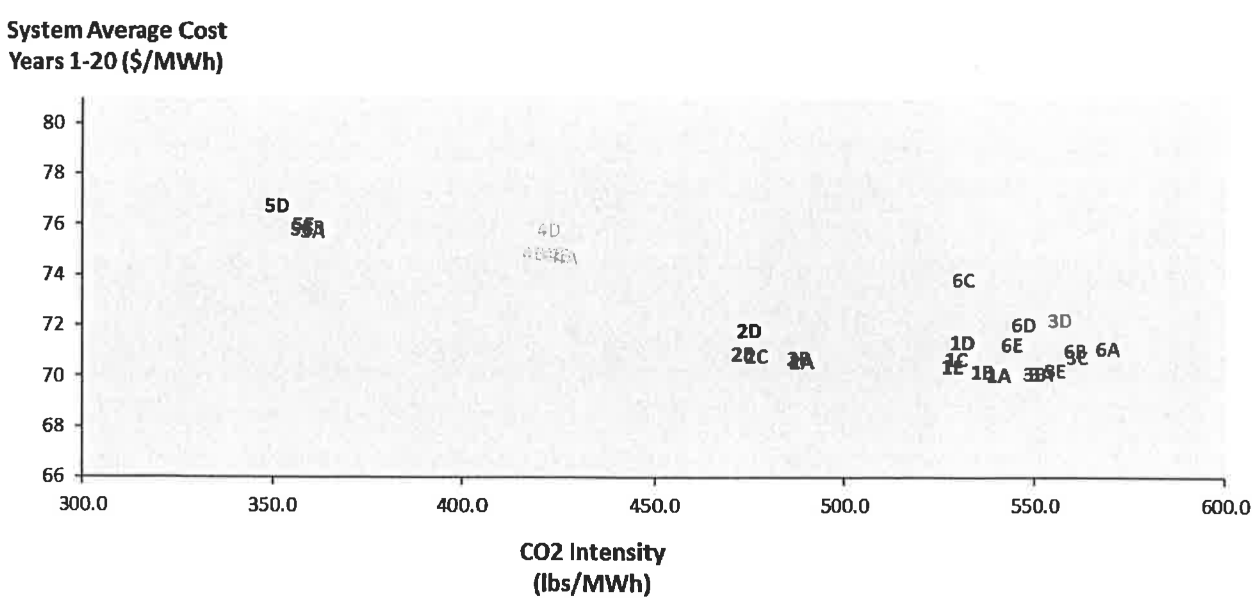



**Figure 8-10: Cost and CO2 Trade-Offs**

### 8.1.3 Operational Flexibility

As described in Chapter 6, understanding system flexibility is a focus in this IRP. Strategy scorecards include two measures of operational flexibility:

- Flexible Resource Coverage Ratio – the ratio of flexible capacity available to meet the maximum 3-hour ramp in demand in 2038
- Flexibility Turn Down Factor – the ability of the system to serve low load periods as measured by the percent of must-run and non-dispatchable generation to sales.

TVA views system flexibility – the ability to cover rapid changes in load demand and to serve low load periods – as a key future consideration for long-range resource planning. This is especially true as the resource mix shifts from conventional, fully dispatchable central station units toward more diverse and dispersed generating assets that introduce more intermittency.

This is the first time TVA has used flexible resource coverage as a metric to assess the performance of a resource portfolio. TVA based this measure in part on research of other utilities and independent system operators in an effort to represent a portfolio's ability to meet rapid changes in demand.

Figure 8-11 shows a comparison of flexible resource coverage ratio and flexibility turn down factor for the Current Outlook. Figure 8-12 displays cost and flexibility trade-offs across all portfolios.

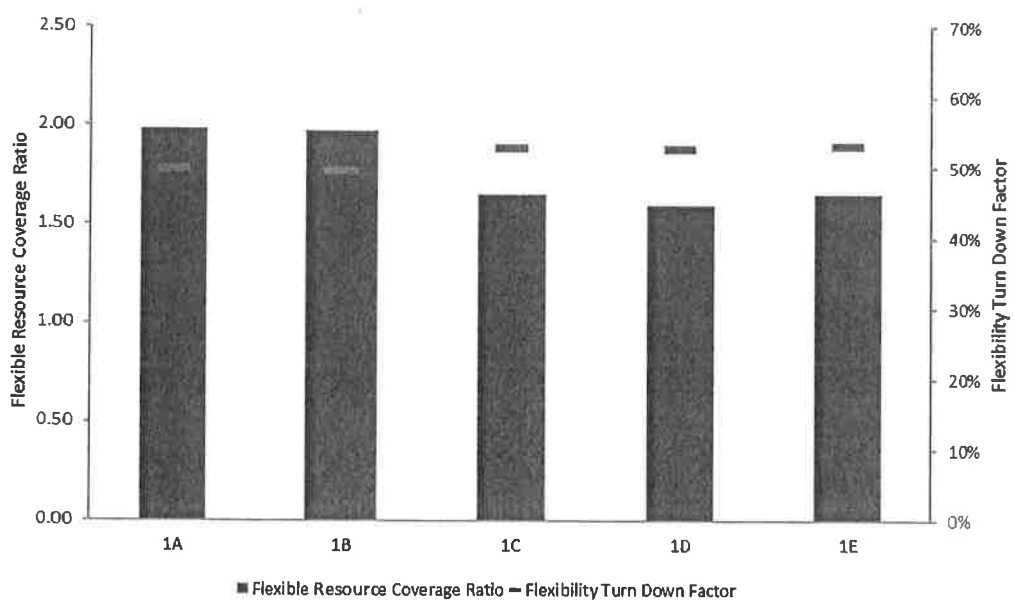



**Figure 8-11: Portfolio Flexibility Profiles (Current Outlook)**

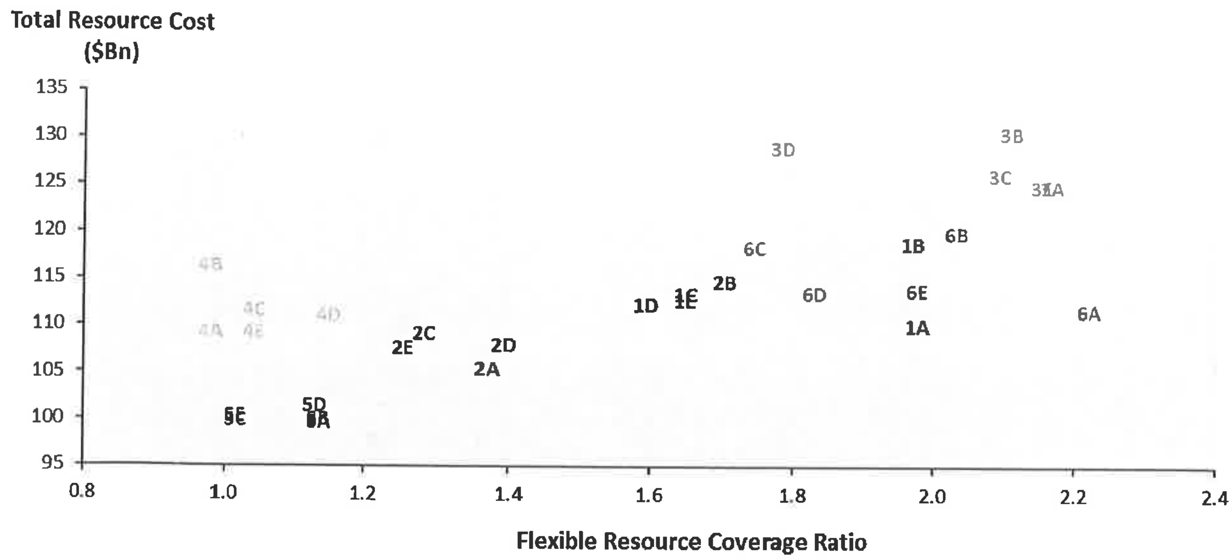



**Figure 8-12: Cost and Flexibility Trade-offs**

TVA's analysis indicates that Strategies A and B result in a more flexible system than other strategies on average. Strategies that drive more solar expansion tend to have lower flexibility. In portfolios where nuclear units are retired (Scenario 6) and replaced in part with gas units, overall system flexibility increases. In general, portfolios with a higher percentage of non-dispatchable resources will have relatively less ability to respond to unexpected load swings.

## 8.1.4 Valley Economics

The impact of different planning strategies on the Valley economy was assessed based on two measures:

- Percent Difference in Real Per Capita Income – the change in real per capita personal income expressed as a change from a reference portfolio in each scenario
- Percent Change in Non-Farm Employment – the change in employment expressed as a change from a reference portfolio in each scenario.

The reference portfolio is the level of impact to per capita income or employment in Strategy A in each scenario. More details about how TVA has computed this macro-economic impact can be found in Appendix J. All strategies have comparable impacts on the Valley economy based on these two standard measures.

Strategy D consistently outperformed the reference income level across all scenarios. This is likely due to the retention of more investment in the Valley under this strategy driven by the commitment to energy efficiency, which results in increased investment in the Valley relative to other resource options. However, the overall variation in per capita income estimates is very small across the strategies, in part due to changes in other factors such as underlying population growth (e.g., in some cases employment increases are matched or even exceeded by larger corresponding increases in Valley population), changes in the composition of employment (increased total non-farm employment yet declining manufacturing employment), and/or changes in regional inflation levels due to higher electricity costs. Furthermore, the scale of TVA incremental investments across the various scenarios and strategies are modest in relation to the overall size of the Valley economy. This suggests that the Valley Economics metric is unlikely to be a key definitive determinate when selecting a preferred target power supply mix.

### 8.1.5 Summary of Observations

Based on analysis of scorecard results, TVA makes the following observations about metric performance across the portfolios:

- The strategy that most leverages utility-scale resources is the most economic and has the lowest risk exposure (Strategy A).
- The strategy that most leverages distributed resources has the highest Total Resource Cost (Strategy B).
- The strategy that most leverages storage has the highest PVRR, driven by current projections for storage prices (Strategy D).
- Strategies that most leverage solar and coal retirements have lower environmental impact overall, but higher land use (Strategies C, D and E).
- Strategies that drive more solar expansion tend to have lower operational flexibility (Strategies C, D and E).
- All strategies have comparable impacts on the Valley economy as measured by real per capita income and employment.

The overall performance of the five planning strategies is explained in more detail below, by metric category in Table 8-1 and by strategy in Table 8-2.

**Table 8-1: Summary of Observations by Metric Category**

| Metric Category | Assessment Observations |
|---|---|
| Cost | • PVRR is similar across the strategies, with Strategy D typically the most expensive<br>• Average system costs are also similar, with Strategies A and B typically lower and Strategy D typically the highest<br>• Total Resource Cost has more variation, with Strategy A the least expensive and Strategy B typically the most expensive |
| Risk | • Strategies with lower costs generally have lower risk exposure<br>• Strategy A has the lowest risk exposure but least favorable risk/benefit ratio, while Strategy D has the opposite profile<br>• Other strategies have moderate risk overall |
| Environmental Stewardship | • All strategies show improvement in air, water and waste categories compared to the current resource portfolio, with Strategy C the most favorable<br>• All strategies show increased land use compared to the current resource portfolio driven by various levels of solar expansion, with the exception of Strategy B |
| Operational Flexibility | • Strategies A and B result in a more flexible system than other strategies, on average<br>• Strategies that drive more solar expansion tend to have lower flexibility<br>• In portfolios where nuclear units are retired (Scenario 6) and replaced in part with gas units, overall system flexibility increases |
| Valley Economics | • All strategies have comparable impacts on the Valley economy as measured by real per capita income and employment |

**Table 8-2: Summary of Observations by Strategy**

| Strategy | Assessment Observations |
|---|---|
| Strategy A:<br>Base Case | • Lowest PVRR, Total Resource Cost, and System Average Cost across scenarios<br>• Lowest risk exposure, but highest risk/benefit ratio<br>• Highest environmental impact overall, but low land use<br>• Best flexibility performance across scenarios |
| Strategy B:<br>Promote DER | • Similar to Strategy A in PVRR and System Average Cost, but most expensive with respect to Total Resource Cost<br>• Risk exposure similar to Strategy A, with moderate risk/benefit profile<br>• Higher environmental impact overall, but lowest land use<br>• Flexibility performance comparable to Strategy A |
| Strategy C:<br>Promote Resiliency | • Mid-range in PVRR, System Average Cost, and Total Resource Cost<br>• Moderate financial risk<br>• Lowest environmental impact overall, but higher land use<br>• Moderate flexibility, comparable to Strategies D and E |
| Strategy D:<br>Promote Efficient Load Shape | • Highest PVRR and System Average Cost due to promotion of storage, and mid-range in Total Resource Cost<br>• Highest risk exposure across the strategies<br>• Low environmental impact overall, but higher land use<br>• Moderate flexibility, comparable to Strategies C and E |
| Strategy E:<br>Promote Renewables | • Mid-range in PVRR and System Average Cost, but lower in Total Resource Cost (second only to Strategy A)<br>• Moderate financial risk<br>• Low environmental impact overall, but higher land use<br>• Moderate flexibility, comparable to Strategies C and D |

## 8.2 Sensitivity Analysis

Each IRP case represents a combination of expectations about the future environment TVA operates in and potential strategies TVA could employ that result in unique resource portfolios. When analyzing results from the draft IRP, TVA identified issues that warranted further evaluation prior to finalizing the study. In addition, TVA received helpful stakeholder input from the IRP Working Group and the Regional Energy Resource Council (RERC), as well as through comments received from the public during the comment period.

Many of the questions raised by TVA and stakeholder review focused on certain key assumptions that could influence results. To explore the impacts of changes in key assumptions and to inform the recommendation ranges in Chapter 9, TVA evaluated sensitivities related to the following categories:

- Natural gas prices
- Storage, wind, CHP, and SMR capital costs
- Greater EE and DR market depth
- Integration cost and flexibility benefit
- Pace and magnitude of solar additions
- Higher operating costs for coal plants
- More stringent carbon constraints

- Variation in climate.

Sensitivity analyses are typically run as variations from the Base Case strategy in the Current Outlook scenario, except where noted, to isolate the impact of a change in one key assumption.

### 8.2.1 Natural Gas Prices

Natural gas generation makes up a significant part of TVA's existing fleet, and several types of gas generation are offered as expansion options. Changes in natural gas prices change the variable cost of gas units and may change the economics of different types of gas capacity relative to other resource options. Two standard deviations above and below the expected value were simulated in the Current Outlook. Figure 8-13 shows the range of natural gas prices for the IRP scenarios and for two standard deviations above and below the Current Outlook forecast.

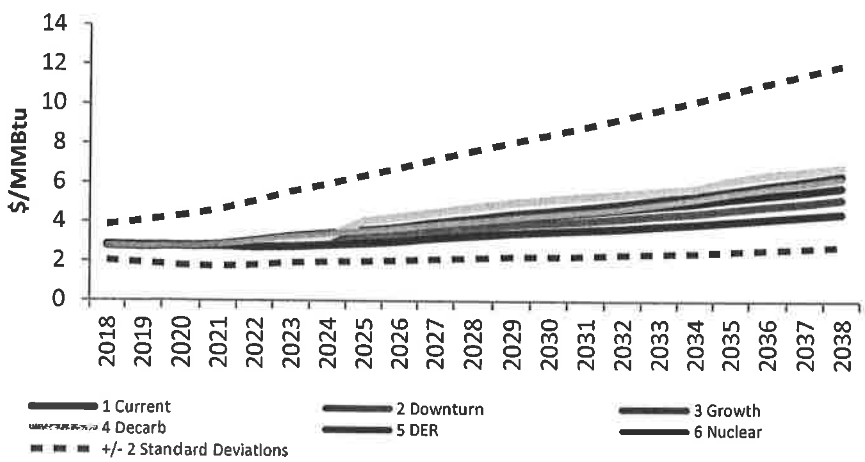



**Figure 8-13: Natural Gas Price Assumptions**

#### Higher Natural Gas Prices

Higher natural gas prices increase the cost of gas generation, making the generation of competing resources more valuable. Solar is projected to become economic compared to gas beginning in the mid-2020s, resulting in 5,900 MW nameplate of solar expansion in the base plan. In the high gas sensitivity, about 2,050 MW nameplate of additional solar capacity is added by 2038 compared to the base case, bringing total nameplate solar expansion to about 8,000 MW in this case. Other changes in the expansion plan include the addition of 55 MW of new hydro, as well as reduced electrification programs driven by the overall higher operating cost for the fleet. The Total Resource Cost increased by about $6 billion due to higher fuel costs. Carbon emissions increased 21 percent driven by an overall increase in coal capacity factors.

#### Lower Natural Gas Prices

Lower natural gas prices improve the economics of gas generation, especially higher efficiency CCs. In the low gas sensitivity, no solar is added, which represents a reduction of 5,900 MW in nameplate solar compared to the base case. Additionally, about 2,000 MW of CT capacity is replaced by CC capacity to better leverage lower gas prices. This sensitivity does not take into account customer demand for renewables that would likely drive more solar additions than economics would dictate. The Total Resource Cost decreased by about $6 billion due to lower fuel costs. Carbon emissions decreased 21 percent driven by an overall increase in gas capacity factors.

### 8.2.2 Battery, Wind, CHP, and SMR Capital Costs

Several resource options that were promoted in an IRP strategy were not selected based on economics in any of the primary portfolios. Of particular interest were battery storage, wind, CHP, and SMRs. TVA, stakeholder groups, and the public expressed interest in understanding how much lower the costs of these resources would need to be for the resource to become economic. TVA performed a breakeven analysis to determine how the IRP costs for battery storage, wind, CHP, and SMR compared to the benefits those units could provide to the system.

The IRP cost is the levelized cost of the resource using Current Outlook assumptions. To determine the benefits the resource could provide to the system, TVA added the resource to the portfolio in the earliest year available at zero cost and calculated the levelized benefit in $/MWh. This approach effectively describes the value of these resources in terms of the avoided energy and capacity from competing resources. As IRP cost approaches breakeven cost, the resource is more likely to be selected in a portfolio.

**Battery Costs**

Even though the IRP assumed a downward trajectory in costs, utility-scale battery storage was not selected based on economics. Due to the varying ways that augmentation and warranty costs can be included in the initial capital investment or paid on an ongoing basis as a fixed cost, direct comparisons between benchmarks requires calibration. As described in Appendix C, TVA matched storage additions to solar additions in strategies where storage was promoted to explore the potential impacts of storage on overall portfolio results. Additionally, TVA performed a breakeven analysis. As battery storage is a higher-value resource, the breakeven value to the system is higher than for wind or CHP. However, using current projections for utility scale battery storage costs, IRP costs are still triple the breakeven value. TVA will continue to monitor rapidly evolving battery storage technologies for improving economics.

**Combined Heat and Power (CHP) Costs**

Although a small amount of CHP did appear in the Promote DER strategy portfolios, the IRP stakeholder working group expressed interest in understanding the breakeven value for CHP without promotion. Analysis indicates that IRP costs for CHP are double the breakeven value. CHP systems also provide steam for space heating, driving additional value for the end-use customer that was not included in the breakeven analysis.

**Wind Costs**

Wind from both outside and inside the Valley has challenging economics. Out-of-Valley wind must be imported to TVA across interconnected systems, driving significant transmission expense. In-Valley wind has lower intensity and efficiency, driving lower capacity factors and higher effective costs. Additionally, the production tax credit is set to expire which will increase costs for all wind options, and IRP costs assume no decreasing technology curve. TVA performed a breakeven analysis for out-of-Valley wind, which had the better cost profile. Analysis indicates that IRP costs for wind are triple the breakeven value.

A further sensitivity case was evaluated to test the effects of a substantially lower wind forecast than the IRP cost assumptions. While IRP assumptions for wind costs were in the range of the National Renewable Energy Laboratory (NREL) ATB mid-case forecast, TVA used the lower bound of NREL's mid-case adjusted to nominal dollars for this sensitivity. Lower prices could be the result of technology improvements, cost efficiencies, tax incentives, or a reduction in transmission costs. Figure 8-14 compares the IRP wind cost assumptions and the NREL lower mid-case cost trajectory, and it includes solar cost projections as an additional reference point.

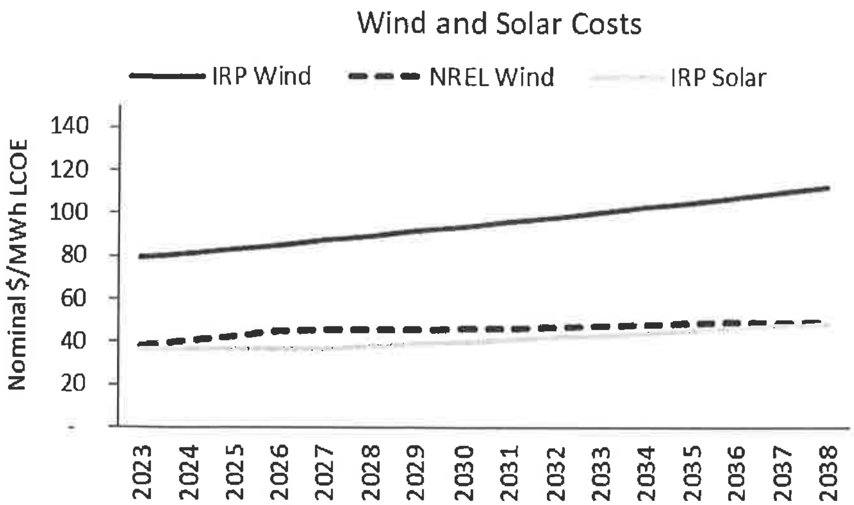



**Figure 8-14: Wind and Solar Cost Comparison**

In the NREL lower mid-case sensitivity, 4,200 MW nameplate of wind capacity was added by 2038. Because wind resources contribute about a third of their nameplate capacity toward meeting winter reserve margin targets, some gas additions were displaced early in the plan. If the lower wind cost materializes, wind would also compete with solar in the latter part of the plan and displace about 3,100 MW nameplate of solar by 2038, reducing solar additions roughly by half.

**Small Modular Reactors (SMR)**

SMR investment would be capital-intensive and represent first-of-a-kind technology deployment at utility scale. Given this, TVA performed a breakeven analysis to help understand the cost gap and inform ongoing discussions with the Department of Energy, a stakeholder that may be willing to share in costs and risks associated with potential SMR deployment. SMRs were evaluated assuming operation beginning in 2028 and running through the end of the study window in 2038. A limitation of this analysis is that capital-intensive resources have long economic lives, and two thirds of SMR economic life would be outside the study window. Analysis indicates that IRP costs for SMRs are more than double the breakeven value. Refinements in design may improve SMR costs, but cost and risk sharing are essential to close the gap.

### 8.2.3 Greater EE and DR Market Depth

Across the primary IRP cases, the amount of available programmatic EE and DR is limited in yearly additions and total cumulative volumes based on projected opportunity. TVA performed a sensitivity to determine the potential impact if EE and DR market depth was greater than projected. Additional tiers of programmatic EE and DR were offered at incrementally increasing costs and with no cumulative volume limit. Analysis indicates about 2,100 MW of additional EE and DR was economic compared to the base case, if higher volumes could be realized at assumed costs. Additional EE and DR displaces about 2,200 MW nameplate of solar and about 2,000 MW of CT capacity. An assumed increase in EE and DR market depth results in a similar PVRR, higher system average cost, and 10 percent lower carbon emissions.

### 8.2.4 Integration Cost and Flexibility Benefit

Integration cost is the sub-hourly economic signal used to represent the cost of balancing an intermittent resource with dispatchable resources. This cost is not recognized in hourly planning models. Conversely, flexibility benefit is the sub-hourly value that highly flexible and dispatchable resources have that also isn't recognized in hourly models. More detail can be found on integration cost and flexibility benefit in Appendix D. Reflecting a sub-hourly integration cost and flexibility benefit was a recent addition to our modeling framework, so TVA performed a sensitivity to evaluate the impact of removing them from our models. Removing integration cost and flexibility benefit drove a very similar end result for resource selection, indicating that these costs and benefits alone do not drive macro-level decision making but would inform evaluation of specific deals, contracts, and decisions.

### 8.2.5 Pace and Magnitude of Solar Additions

Limits on the pace, timing, and magnitude of resource additions are common in modeling, as they serve to create more realistic resource plans. For example, the ability to construct or contract resources may be limited by the market or by the ability of operations to integrate new resources into the portfolio. Annual limits in a model that has perfect foresight also prevents over-optimizing resource selections in any single year. TVA, stakeholder groups and the public raised questions about the impact of limitations on solar, in particular. Solar was limited in three ways in the primary cases, as follows:

- 2023 earliest online date, driven by August 2019 IRP publication date and subsequent time required for interconnection requests and environmental permitting
- Annual addition limit of 500 MW nameplate, reflecting other utilities' experience with average annual solar additions
- Cumulative limit of 10,000 MW nameplate based on the study window time frame and system turndown capability.

TVA performed a sensitivity to evaluate the impact of accelerating solar additions to as early as 2021 to align with two programs to support accelerated renewable investment launched after the IRP base case was established. These programs include the Renewable Investment Agreement (RIA) and the Flexibility Research Project (FRP) pilot. RIA supports utility scale buildouts for large commercial and industrial customers, and FRP supports community solar in partnership with LPCs. In this sensitivity, TVA reflected recent solar signings of about 700 MW scheduled to come online in 2020/2021 (contracted after the IRP base case was established) and assumed 500 MW per year of accelerated solar additions thereafter until economic solar additions pick up in the mid-2020s. Analysis of potential acceleration indicates about 1,100 MW nameplate of additional solar by 2038 compared to the base case.

TVA also performed a sensitivity that doubled the annual addition limit to 1,000 MW and removed the cumulative limit. This analysis indicates a similar result of about 1,100 MW nameplate of additional solar by 2038 compared to the base case.

In discussions about the solar sensitivities evaluated in the Current Outlook, stakeholder groups inquired if results might be different in other scenarios. TVA performed an additional sensitivity to test the impact of increasing annual and cumulative limits in the Valley Load Growth base case (3A). Higher electricity demand with no additional base load resources added would lower the turndown pressure in the growth case. This additional sensitivity was run with an annual addition limit of 1,000 MW and a cumulative limit of 14,000 MW, which is roughly the difference between the growth scenario load profile and the output of baseload nuclear and hydro resources adjusted for pumped storage ability to shift some baseload. Analysis indicates 6,000 MW nameplate of additional solar compared to the growth scenario base case, or 14,000 MW nameplate of solar additions in total. Other expansion changes include 1,000 MW of CCs replaced with CTs.

### 8.2.6 Higher Operating Costs for Coal Plants

When reviewing results of the primary cases, TVA and stakeholders had questions about the ongoing operating costs for TVA's coal fleet. Aging coal units expected to operate more frequently outside their design, driven by low gas prices and increasing renewables on the system, have a greater risk of substantially increased operating costs. To assess the potential impact, TVA performed a sensitivity simulating a high trajectory for operations and maintenance costs and capital costs for the coal plants, as well as higher environmental spend. Unit performance assumptions remained the same as in the base case, while total non-fuel costs were increased by over 60 percent on average on a present value basis.

Analysis indicates the potential for about 2,200 MW of coal to be retired by 2028. As the retired coal capacity had relatively low capacity factors overall, CTs were the preferred replacement resource.

### 8.2.7 More Stringent Carbon Constraints

When reviewing results of the primary cases, stakeholders inquired about the potential impact of a higher than projected carbon penalty in the Decarbonization scenario.

To assess this, TVA performed a sensitivity off the Decarbonization base case (4A) that doubled the carbon penalty to $40-80/ton and reflected the cascading impact in natural gas and power price forecasts. Figures 8-15 through 8-17 shows a comparison of the key assumptions in the Current Outlook and Decarbonization base cases compared to the double decarbonization sensitivity case.

Analysis indicates an acceleration of about 2,200 MW of coal retirements that were already present in the Decarbonization base case. CC expansion was accelerated, displacing coal generation, and 175 MW of hydro generation was added by 2038.

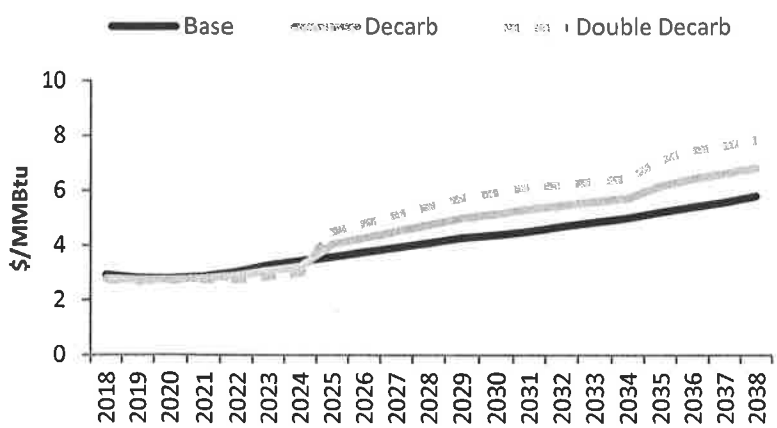



**Figure 8-15: Natural Gas Price Forecast**

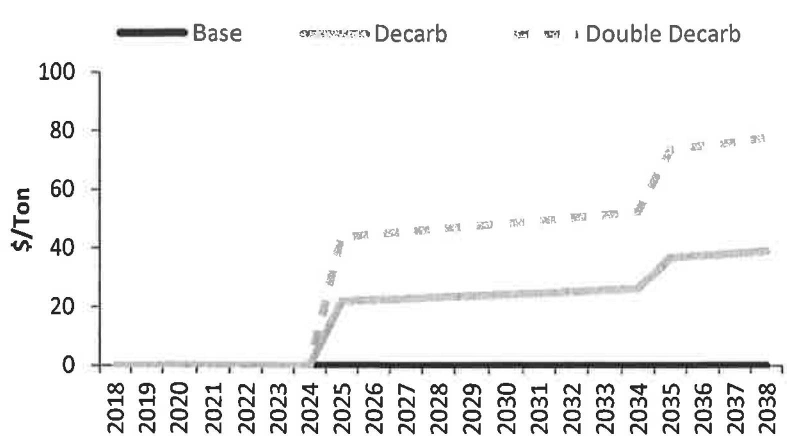



**Figure 8-16: Carbon Price Forecast**

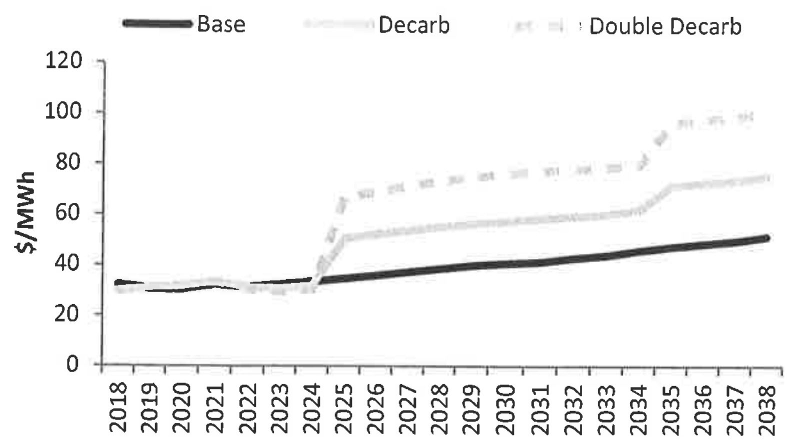



**Figure 8-17: Power Price Forecast**

### 8.2.8 Variation in Climate

Stakeholders also expressed interest in understanding how variation in climate may impact capacity expansion plans. Based on an USEPA report (USEPA 430-F-16-004, "What Climate Change Means for Tennessee"), the effects of climate change may mean hotter, drier summers and warmer, wetter winters. Hotter and drier summers will reduce the output of thermal and hydro resources and increase loads. On the other hand, a warmer and wetter winter will decrease loads and increase hydro generation. TVA performed a sensitivity to gauge the impact of a 3° F increase in the average annual temperature across the Tennessee Valley, coupled with changes in seasonal rainfall.

Analysis for this sensitivity indicates that the TVA system would become summer peaking. CT additions are accelerated to replace the impact of derated coal and nuclear capacity in the summer until about 2,100 MW nameplate of additional solar can be added to help maintain summer reserve margins. Total Resource Cost increased by about $3 billion due to the increased summer peak and thermal derates in the summer, while carbon emissions improved slightly due to increased solar and hydro generation and decreased coal generation.

### 8.2.9 Summary of Sensitivity Cases

The sensitivity cases TVA performed that have the potential to impact capacity expansion are summarized below in Figure 8-18. Capacity expansion impacts are shown by resource type, with increases highlighted in green and decreases highlighted in red. The results from the sensitivity cases were considered in developing the IRP Recommendation.

# Chapter 8: Strategy Assessment and Next Steps

| SENSITIVITY CASE<br>Base Case comparison is the Current Outlook unless otherwise noted | CAPACITY EXPANSION IMPACTS BY 2038<br>GREEN indicates increase and RED indicates decrease in resource type | | | | | | |
|---|---|---|---|---|---|---|---|
| | Nuclear | Coal | Gas | Hydro | Solar<br>Nameplate | Wind<br>Nameplate | EEDR |
| Higher Natural Gas Prices | | | | +55 MW | +2,050 MW | | |
| Lower Natural Gas Prices | | | 2,000 MW CT replaced by CC | | -5,900 MW | | |
| Lower Wind Costs | | | -1,100 MW | | -3,100 MW | +4,200 MW | |
| Greater EE & DR Market Depth | | | -2,000 MW | | -2,200 MW | | +2,100 MW |
| Integration Cost & Flexibility Benefit | | | Minor timing differences | | Minor timing differences | | |
| Pace & Magnitude of Solar Additions | | | | | +1,100 MW | | |
| Magnitude of Solar Additions (Valley Load Growth) | | | 1,000 MW CC replaced by CT | | +6,000 MW | | |
| Higher Operating Costs for Coal Plants | | -2,200 MW | +1,500 MW | | | | |
| More Stringent Carbon Constraints (Decarbonization) | | -2,200 MW accelerated | CC expansion accelerated | +175 MW | | | |
| Variation in Climate | Summer derates | Summer derates | CT expansion accelerated | | +2,100 MW | | |

**Figure 8-18: Summary of Sensitivity Cases**

# 10 Implementation

This chapter outlines some of the challenges and next steps TVA faces in implementing the recommendations of the IRP study, and discusses key policy considerations and improvements to modeling and the study process.

## 10.1 Overview of Next Steps

In finalizing the IRP and EIS and developing the IRP Recommendation, TVA considered the input received during the comment period. No earlier than 30 days after publication of the notice of availability of the Final IRP/EIS in the Federal Register, the TVA Board of Directors will be asked to make a decision on the IRP Recommendation. After the Board makes a decision, the NEPA process is completed by issuing a Record of Decision that documents the Board's action and its basis.

## 10.2 Implementation Challenges

The Regional Energy Resource Council (RERC), after reviewing the recommendations in the IRP, offered the following advice to the TVA Board:

1. TVA should monitor federal and state regulations, legal challenges, and industry changes that may alter the broader energy environment and take appropriate actions to mitigate risks to the power system's reliability and costs.
2. TVA should continue to work with local power companies, directly served customers, and stakeholders to collaborate on Distributed Energy Resources (DER) and distribution planning; build greater visibility into customer needs; and prepare for associated data management. Standardization of cost-effective DER smart technologies will enable the system to efficiently utilize distributed resources.
3. TVA should continue engaging with stakeholders early in any decision process on the site selection for solar, gas power generation, and utility-scale energy storage to avoid land-use conflicts, encourage the utilization of existing infrastructure assets, and maximize system benefits. In addition, TVA should continue to analyze small-scale, flexible, carbon-free nuclear resources for their potential inclusion in a diverse portfolio.
4. TVA should continue evaluating gaps in data, including customer needs and desires, the speed of technology advancement, locational value, flexibility value, etc., in order to inform and be prepared for future IRPs. TVA should also explore advanced data tools to support the analysis.

*(Above excerpt from the advice provided by the TVA Regional Energy Resource Council on June 27, 2019. See www.tva.gov/rerc for the full advice statement).*

The IRP Recommendation includes significant renewables expansion, introducing operational challenges required to manage intermittency and dynamic loads. Enhanced awareness of the location of renewable resources, both utility and distributed scale, and to weather impacts on solar generation, will become increasingly important. Early experience with battery storage on the system will provide additional insight as to how the various storage use cases might be employed to further support renewables integration and provide economic benefit.

Implementing the recommendations from the IRP will require close cooperation between TVA, local stakeholders, Local Power Company (LPC) partners and Valley electric customers, particularly around deployment of distributed energy resources. TVA is primarily a wholesale power provider and the LPCs have the relationship with most end-use customers. TVA will need to partner with LPCs and other stakeholders in the region to better understand the potential for distributed resources in the Valley and their locational value to inform resource decisions.

The IRP Recommendation also includes more conventional resources, primarily gas-fired, that come with their own implementation challenges in the areas of siting and permitting, both for the units themselves and for the transmission lines and gas pipelines associated with them. TVA has several teams working on various aspects of the siting and permitting work necessary to ensure that when these resources are needed as part of the generation portfolio, TVA will be better positioned to add them to the resource mix.

## 10.3 Policy Considerations

The IRP is a resource planning study focused on identifying a target power supply mix for TVA. In the process of developing the cases and reviewing the results with stakeholders, a number of policy-related issues were raised that are outside the scope of the IRP itself, but will need to be considered as we move toward implementation of recommendations from the study.

- Continued evolution of programs that provide flexibility for customer-owned generation
- Evolution of Federal/State energy and environmental policies
- Advancements in customer expectations and requirements for clean energy
- Enhancing low income equity and energy/environmental justice

We also realize that the level of electric rates and job growth are critical concerns for Valley governments, businesses and residents. The IRP uses two specific metrics for the macro-economic impacts of resource strategies. These metrics and underlying analyses provide important information about future revenue requirements that affect future rate levels and will help inform the future direction of TVA's economic development program. However, none of the strategies had a significantly different impact from the others on the Valley economy. Section 5.5.6 of the EIS provides more information about socioeconomic effects.

## 10.4 Next Steps

The scenarios and strategies evaluated in the IRP provide insights to how TVA's resource portfolio may need to evolve as the future unfolds. The results also indicate near-term actions that provide benefit across multiple futures. TVA is planning to implement the following near-term actions as part of the IRP:

- Add solar based on economics and to meet customer demand
- Enhance system flexibility to integrate renewables and distributed resources
- Evaluate demonstration battery storage projects to gain operational experience
- Pursue option for license renewal for TVA's nuclear fleet
- Evaluate engineering end-of-life dates for aging fossil units to inform long-term planning
- Conduct market potential study for energy efficiency and demand response
- Collaborate with states and local stakeholders to address low-income energy efficiency across the Valley
- Collaboratively deploy initiatives to stimulate the local electric vehicle market
- Support development of Distribution Resource Planning for integration into TVA's planning process.

As the future evolves, TVA will monitor key signposts that will guide decisions for the long-term. Signposts relate to key variables that could have a significant influence on the future generation portfolio. Key signposts include:

- Demand for electricity
- Natural gas prices
- Customer expectations
- Regulatory requirements
- Operating costs for existing units
- Solar and wind costs
- Emerging and developmental technologies.

TVA will closely monitor these key drivers related to changing market conditions, more stringent regulations, and technology advancements to inform appropriate actions within the recommended ranges and appropriate timing for initiating the next IRP.

## 10.5 Conclusion

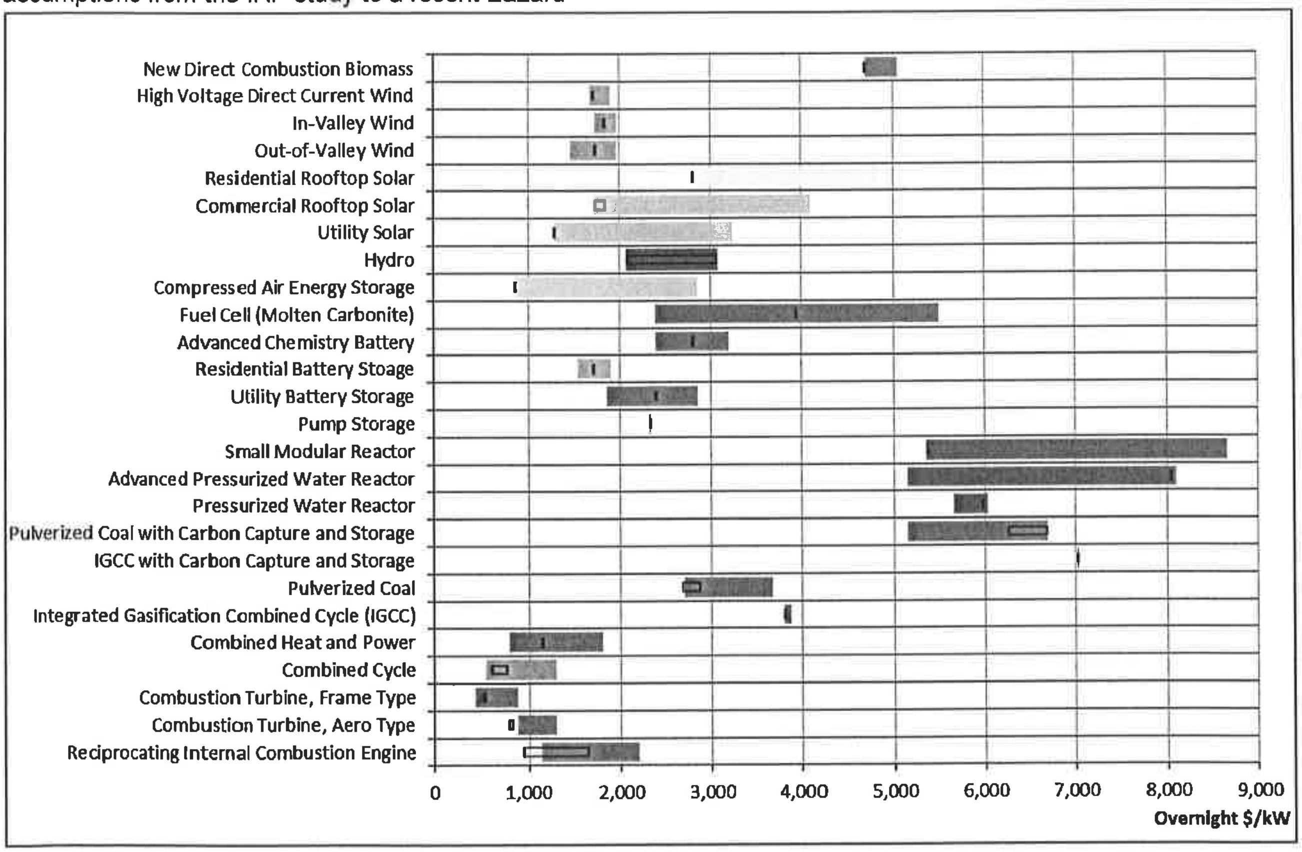
TVA finds considerable value in undertaking an IRP and especially appreciates the input, review and insights of individuals on the IRP Working Group and the RERC. The IRP Working Group and RERC members spent considerable time helping TVA develop a robust plan that meets the criteria outlined in TVA's objectives. TVA values their involvement and the expertise they provided on behalf of their stakeholders in the development of this IRP.

As with any long-term plan, TVA's IRP reflects what we know today and can reasonably expect for the coming years. TVA, along with our employees across the Valley, stands ready to carry out its three-part mission around energy, the environment and economic development. In an ever-changing world, TVA will do its best to continue to serve the people of the Tennessee Valley by providing low cost, reliable and clean power in an environmentally responsible manner while promoting economic development across the Valley.

# Appendix A – Generating Resource Cost and Performance Estimates

that the majority of assumptions proposed for the study were consistent with typical values used in the industry. Many of the remaining assumptions were modified, based on Navigant's recommendations, prior to running the IRP cases. The data in the table presented in the preceding section reflects adjustments recommended by Navigant.

TVA also prepared a comparison of its capital cost assumptions from the IRP study to a recent Lazard report, EIA data and other utility IRPs to further verify the reasonableness of TVA's assumptions. This comparison chart, Figure A-1, shows how TVA's assumptions on capital costs compare to those recently published sources. The cost comparisons are generally consistent given that the majority of the data points are based on national averages and TVA's costs are specific to the TVA system and reflect recent project experience and quotes.




Colored bars reflect benchmark ranges and black outlines represent TVA assumptions;
TVA assumptions outside of benchmark ranges are based on actual costs of TVA projects or vendor quotes.

**Figure A-1: Benchmark Ranges of Capital Costs and IRP Values.**

## A.4 Modeling Approach for Wind & Solar Options

Wind and solar resources have unique operating characteristics that are different from thermal and other more traditional resources. To properly account for the contribution from these intermittent resources, the energy contribution is represented using hourly energy profiles that are imported into the model, and the seasonal capacity of these resources is represented by a computed Net Dependable Capacity (NDC) value. The annual capacity factor of the hourly energy profiles is also computed to ensure the total amount of energy is comparable to industry benchmark sources. This appendix discusses the methodology TVA used to determine both the energy profiles and NDC values for wind and solar options that are considered in the IRP.

# Appendix A – Generating Resource Cost and Performance Estimates

### A.4.1 Wind Modeling

Generation from wind is weather and location dependent and not dispatchable like more conventional resources. Therefore, utilities need to develop a reasonable representation of the output from wind for use in long-range planning models. This "wind shape" is based on actual data collected from specific sites, or modeled data using wind turbine design assumptions.

TVA uses a combination of data from 3TIER, a third-party company specializing in renewable energy assessment and forecasting, and data from TVA wind PPAs to develop the planning assumptions around wind shape and capacity factor for use in the IRP. A "typical week" hourly shape for each month was developed by 3TIER for each wind option. From these shapes, the amount of energy produced can be determined and a capacity factor computed (actual generation expressed as a percentage of maximum possible generation).

### A.4.2 Wind Capacity Factors

TVA used actual results from its wind contracts (1,200 MW in Oklahoma, Illinois, Kansas and Iowa), simulated and actual data for the in-Valley sites, and proposals for various projects to determine the capacity factors for the wind resources options included in the IRP. Since each of the options originates from different regions, TVA used a region-specific estimate for annual capacity factors. For modeling purposes, TVA assumed the MISO and SPP option had a 40 percent capacity factor, the HVDC option originating from Oklahoma had a 55 percent capacity factor, and the in-Valley option had a 30 percent capacity factor.

The HVDC project has a 55 percent annual capacity factor due to the availability of wind in Oklahoma and the newer technology of the wind turbines, which were assumed to be GE 1.7-100 wind turbines at a height of 80 meters. This capacity factor is much higher than TVA's existing wind contracts in other locations. Figure A-2 shows the range of capacity factors:

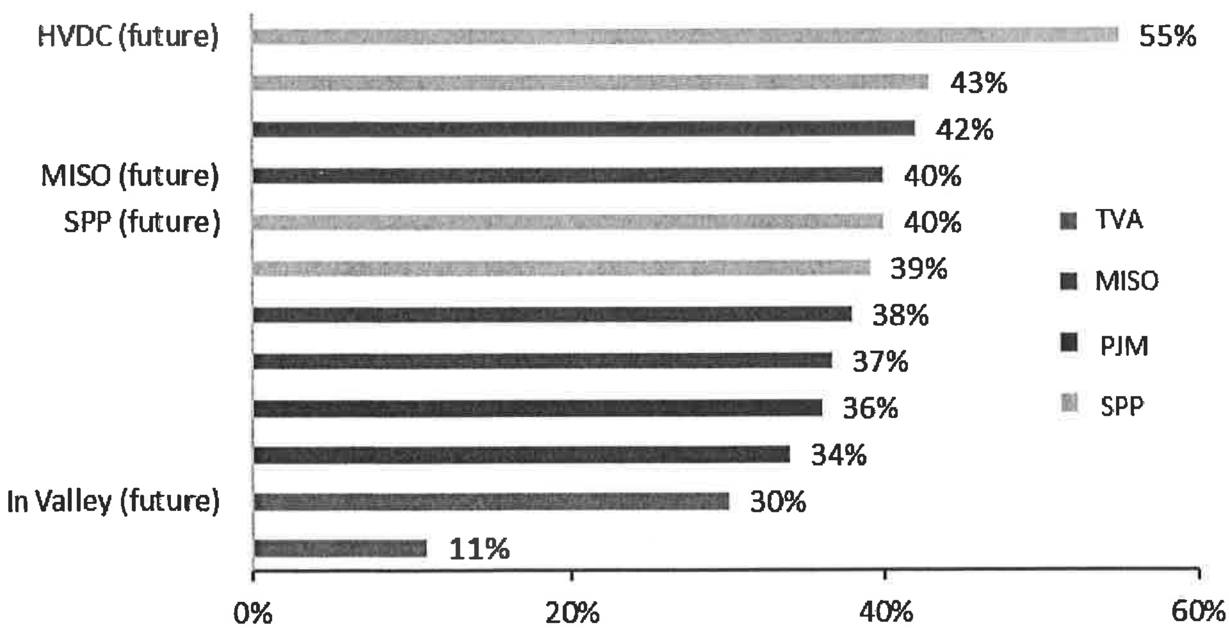



**Figure A-2: Wind Capacity Factors.**

### A.4.3 Wind Net Dependable Capacity

Planners must determine how much wind generation is likely at the summer and winter peak hours so that appropriate Net Dependable Capacity (NDC) credit can be given to wind resources when computing the capacity/load balance to determine if the required reserve margins have been met in a given year. The NDC is applied to the nameplate capacity and is used by the expansion model as a wind resource's contribution toward meeting reserve margin requirements.

For this IRP study, TVA used 39 years of simulated and actual hourly wind data ranging from 1980 to 2018. This 3TIER study simulated data was not updated for this IRP as material changes in historical and simulated wind data were not expected. The wind generation was based on simulation of TVA's existing wind contracts in MISO, SPP, and PJM as well as a site in Kansas near the proposed HVDC site. TVA and 3TIER data were used to assess the long-term variability of the wind for each site in a retrospective analysis of historical wind speed and power. These data points were derived from a mesoscale Numerical Weather Prediction (NWP) model that was statistically calibrated to match the observed data during the measurement period at the height of the towers. An example of the variability of the wind net power is shown in Figure A-3.

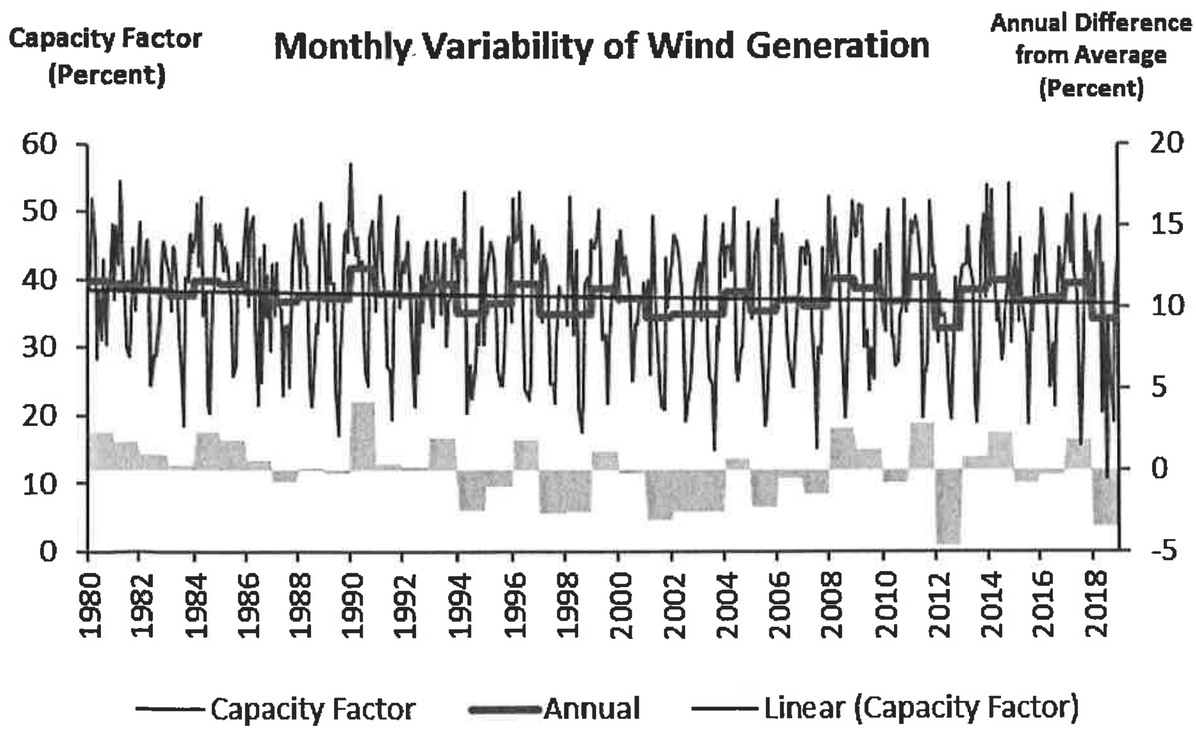



**Figure A-3: Example of Wind Monthly-mean variability.**

NDC was calculated as 14 and 31 percent for summer and winter, respectively, based on a portfolio view of all current wind contracts to capture the diversity of location across the different states of the region (i.e., Oklahoma, Kansas, Illinois, Iowa). These NDC values were used for all wind options. Further detail on how wind NDC values were calculated is included in the Intermittent Resources Study section of Appendix D.

Because specific sites of future wind in MISO, SPP or In-Valley is unknown, it would be inappropriate to assume a different NDC at this time. A more specific NDC would be incorporated into the wind portfolio NDC calculation once specific sites are known. TVA did not consider over-subscription contracts where transmission is limited to a level below the nameplate rating of the wind capacity which tends to improve both the annual capacity factor and the NDC rating. The costs associated with the wind projects modeled in the IRP do not reflect oversubscription. In TVA's experience with several existing wind contracts, this over-subscription provision is negotiated through the terms and costs of a particular contract and is not easily comparable to industry benchmarks.

### A.4.4 Solar Modeling

Similar to wind, solar resources are also weather and location dependent. Modeling of solar options in the IRP proceeds in a similar fashion to wind, and requires determination of solar shapes, capacity factors and NDC values. Solar data for the 2015 IRP was provided by members of the TVRIX stakeholder group who commissioned Clean Power Research (CPR) to provide TVA with the solar energy profiles for 26 sites across the Tennessee Valley shown in the map below. CPR provided SolarAnywhere® data for 15 years (1998-2013) of consistent, validated, time-series irradiance measurements that provided the historical basis for the NDC, capacity factors and hourly energy patterns. This data was collected for the 2015 IRP and was not updated as material changes were not expected. However, TVA also incorporated capacity factors and hourly generation patterns from TVA solar PPAs to inform assumptions in the 2019 IRP.

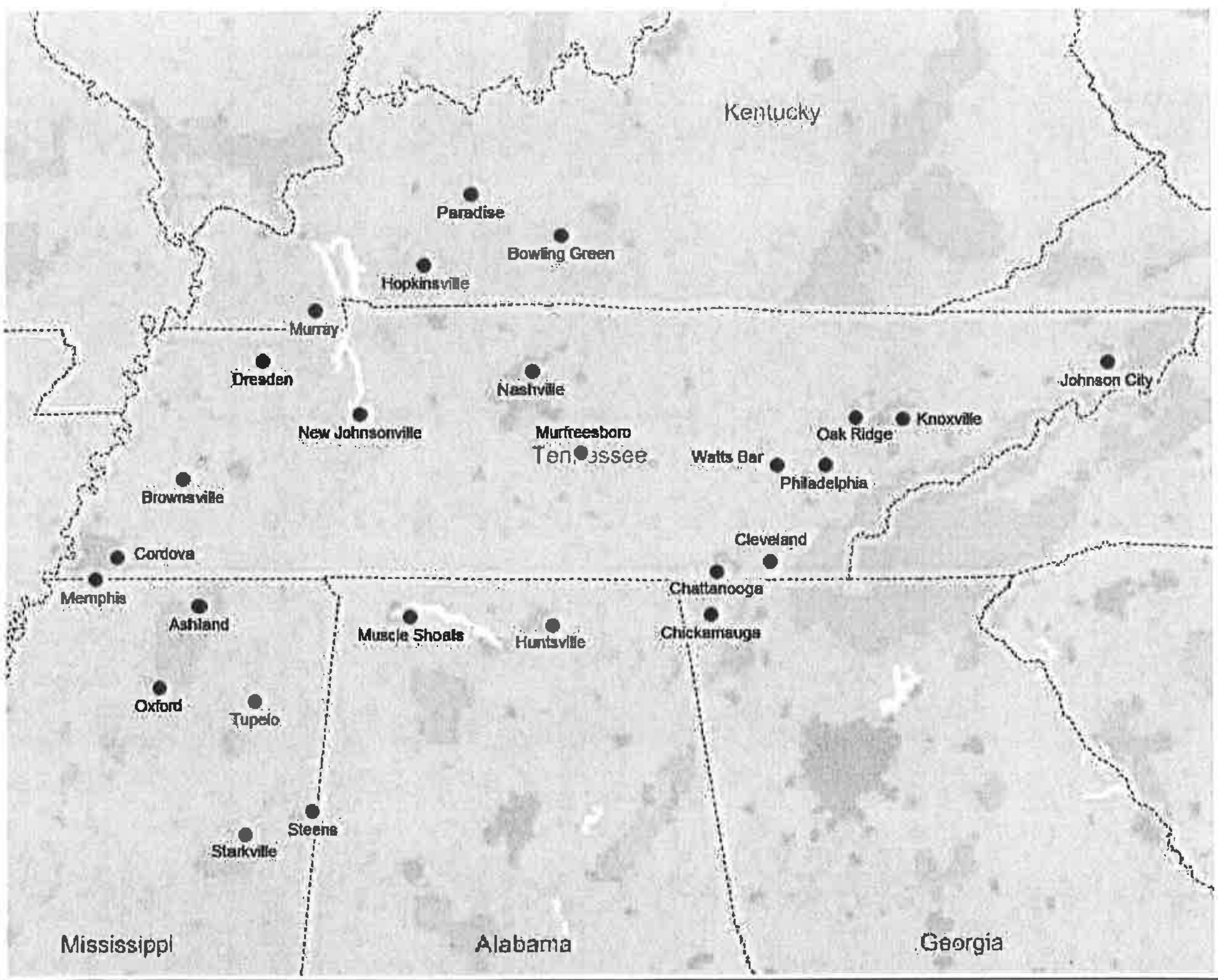



**Figure A-4: Sites across Tennessee Valley with historical solar irradiance data supplied by CPR.**

# Appendix A – Generating Resource Cost and Performance Estimates

### A.4.5 Solar Capacity Factors

Using the data supplied through CPR as well as PPA data, TVA determined that annual capacity factors are 20 percent for the fixed axis and 23 percent for the single-axis tracking option. The monthly capacity factors vary as shown in the following chart.

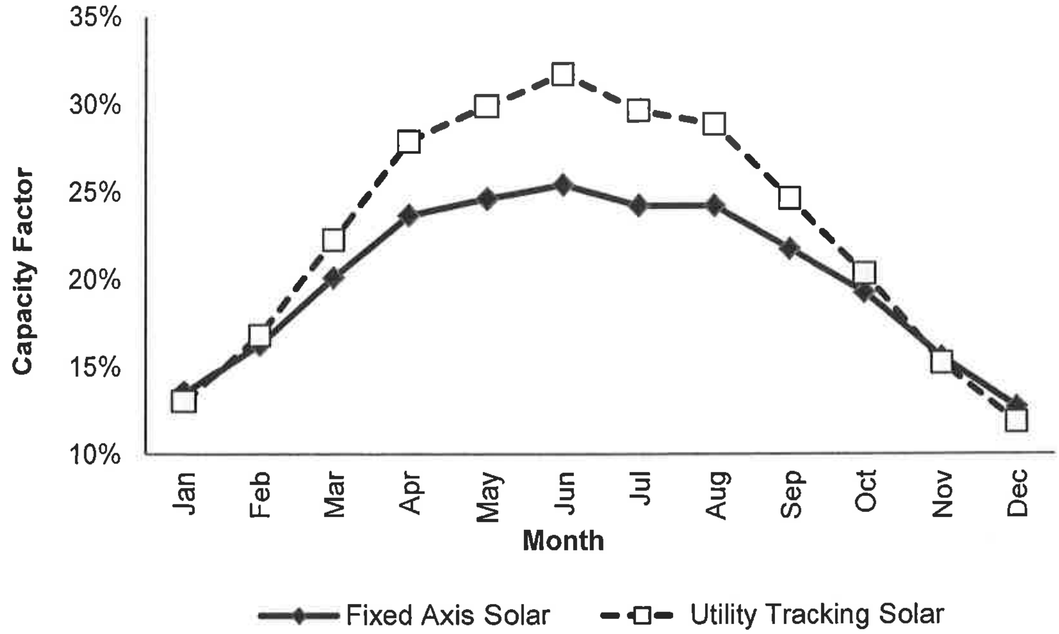



**Figure A-5: Solar Fixed Axis and Utility Tracking Capacity Factors by Month.**

### A.4.6 Solar Net Dependable Capacity

The determination of the NDC for solar resources utilizes the same process as described for wind resources. The figure below shows the range of NDC values for solar fixed-axis systems computed using the CPR and TVA PPA data.

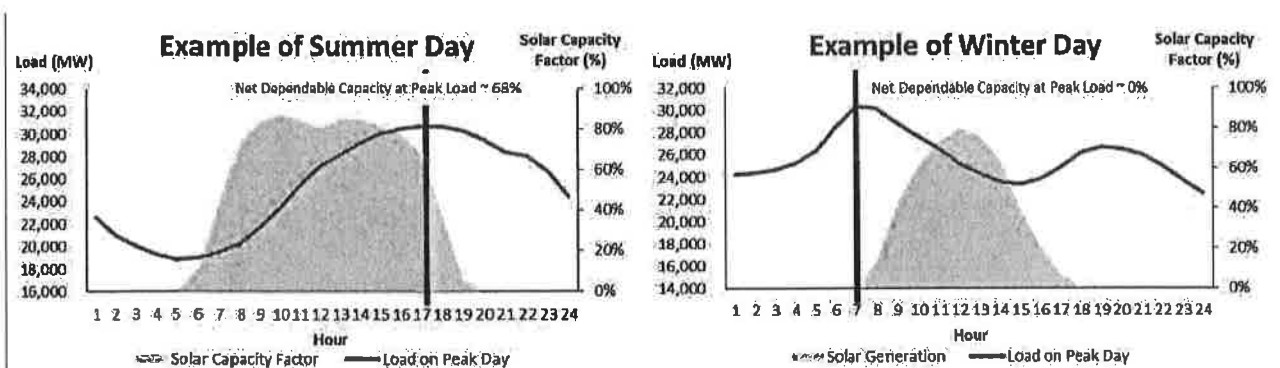



**Figure A-6: NDC by hour for Summer and Winter.**

In the summer, TVA normally has a peak load at 5:00 p.m. CST, but can also see a peak load between the hours of 2:00 p.m. and 6:00 p.m. CST. The 25th percentile of solar generation of those hours would occur at 5:00 p.m. or 6:00 p.m. CST as the sun is setting. Therefore, the summer NDC was set at 50 percent for fixed axis at all scales. The utility tracking option has a 68 percent summer NDC. All solar options have a zero percent NDC during the winter, since TVA's winter peaks normally occur around 7:00

a.m. CST when solar is not available. Further detail on how solar NDC values were calculated is included in the Intermittent Resources Study section of Appendix D.

# Appendix C: Distributed Generation Methodology

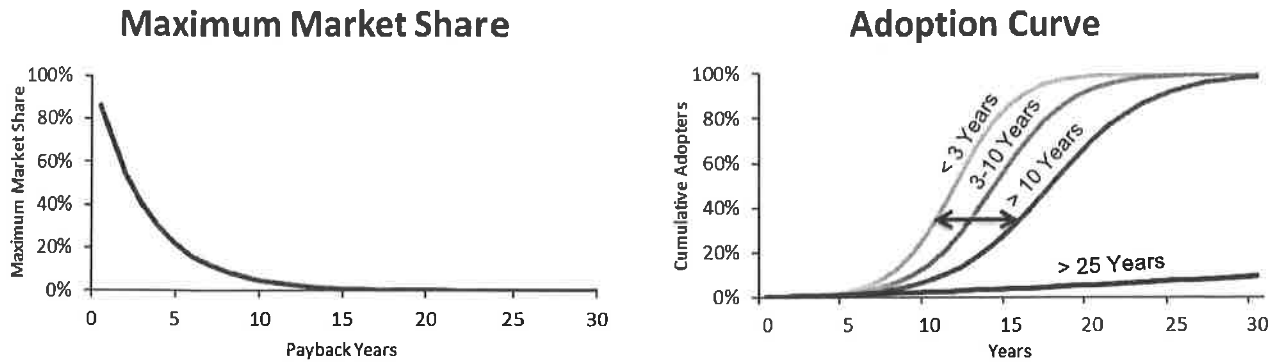



**Figure C-6: Concept Illustration of NREL's Distributed Market Demand Model.**

## C.3.1 Payback Period

A key element in the model is the payback period, which is simply the number of years required for a consumer to recoup the upfront costs of an investment. Ignoring discount rates, an example project requiring an upfront capital investment of $10,000 that saves a net $1,000/year will have a payback period of 10 years. The lower the payback, the greater the market depth, as more Valley residents see value in adopting a particular technology. Even with an acceptable payback, not all consumers will adopt the technology at the same time. This occurs for a variety of reasons. Some consumers are more comfortable using new technologies than others and are likely to adopt sooner, while others will wait. Also, a consumer must have access to the capital required to cover the initial costs of the technology investment. Even with the necessary capital, whether or when a consumer purchases a technology depends on competing uses for the funds and other practical considerations. All these factors impact the pace of DG adoption, which happens over the course of years and is generally faster with quicker paybacks.

## C.3.2 Payback Components

There are two primary components in calculating payback for a DG investment – electricity bill savings and DG investment. To estimate electricity bill savings, forecasts for residential and commercial average effective rates were applied to the average annual energy output of a DG system. Next, it was necessary to estimate projected prices for distributed solar, storage and CHP systems. Pricing information for DG resources was derived from a variety of sources, both internal and external to TVA. Distributed solar prices were obtained from Navigant Consulting, with references to NREL studies. These studies contained historical solar prices for all customer segments, up to 2017. These prices were then projected into the future, using pricing improvements TVA has seen in recent solar requests for information and proposals as a directional guide for near-term movements.

Distributed battery prices, including installation costs, were derived from market prices for Tesla Powerwall 2 systems. These prices were projected into the future using IEEE mid-range projections as a directional guide. CHP prices were derived from a combination of information sourced from the Southeast CHP Technical Assistance Partnership and internal TVA surveys of universities, hospitals and commercial entities. Escalation rates for all DG resources can vary by scenario, driven by assumptions around tax policy and pace of technology advancement. Figure C.7 shows assumptions for distributed solar and storage cost projections.

# Appendix C: Distributed Generation Methodology

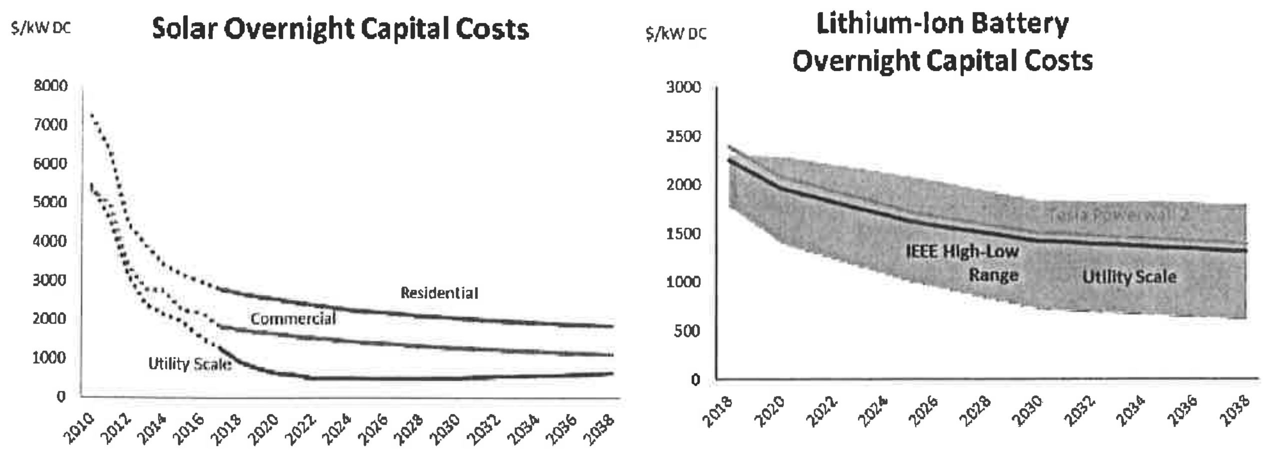



**Figure C-7: Distributed Solar and Storage Price Forecast.**

Further information about resource options and assumptions can be found in Chapter 5 and in Appendix A: Generating Resources.

## C.3.3 Adoption Levels

Using assumptions for payback, considering assumptions unique to each scenario and strategy combination, the DG model provides forecasts for the following:

- Base levels of DG, considering TVA programs and payback without additional incentives
- Level of DG with moderate incentives
- Level of DG with high incentives

An example of the DG model output, specifically the resulting levels of DG adoption for Scenario 1 (Current Outlook), is shown in the figures below.

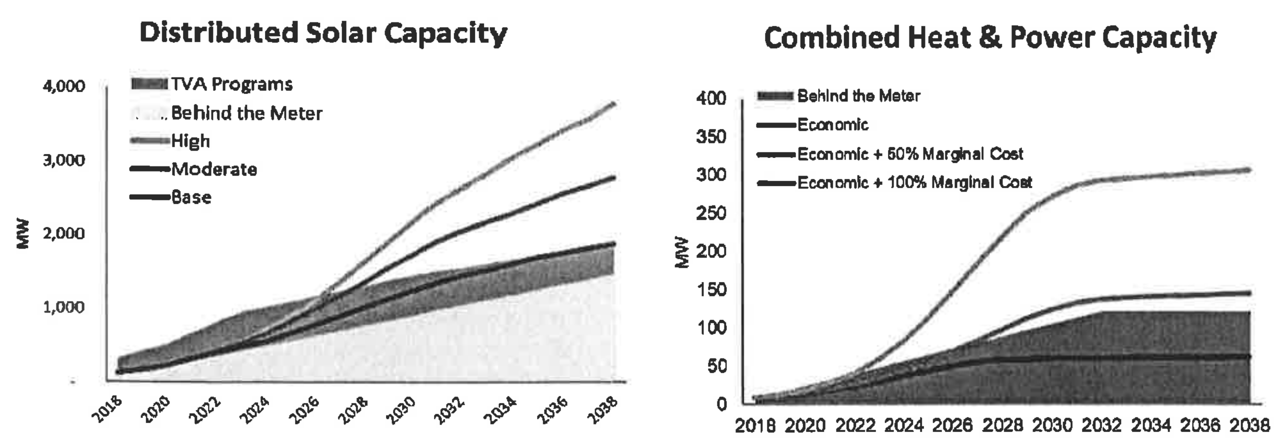



**Figure C-8: Distributed Solar and CHP Capacity, Current Outlook Scenario.**

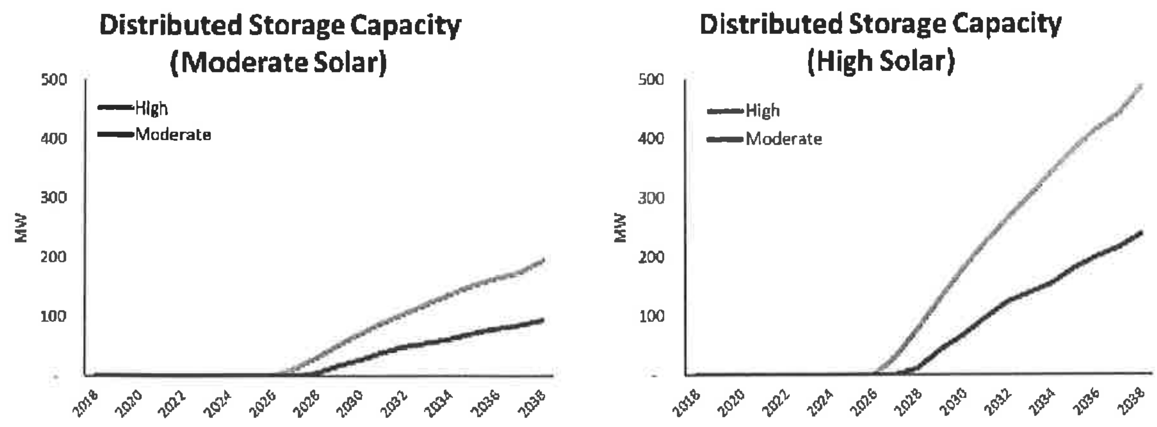



**Figure C-9: Distributed Storage Capacity, Current Outlook Scenario.**

## C.4 Step 4: Enforce New Adoption Level in Expansion Model

Once the DG profiles are created for distributed solar, distributed storage and CHP, they are imported into the expansion model. A unique set of DG adoption levels is fed into the expansion model for each scenario and strategy combination. The DG adoption levels are treated as required resources, or effectively a constraint the model has to operate with prior to optimization of other resources.

## C.5 Step 5: Optimize Balance of Resources for the Portfolio

After the DG profiles for distributed solar, distributed storage and CHP are imported into the expansion model as required resources, the expansion model will then be run to optimize the remainder of the portfolio. This action is performed for each scenario and strategy combination, considering the aims and bounds of the strategy and all available generation and programmatic resources. The Reserve Margin is an important consideration in this step, ensuring that the expansion path chosen results in a portfolio that meets or exceeds seasonal reserve margin requirements to support a reliable system at the lowest feasible cost for a given strategy.

## C.6 Conclusion

TVA's 2019 IRP utilizes an innovative methodology to forecast the impact of different strategies on DG penetration across various future scenarios. The method simulated the effect of monetary incentives reducing payback and driving higher adoption of DG technologies. Results from the model allow TVA to gain insights into the impact that distributed generation could have on the TVA system under a variety of different future states. This knowledge will further inform future planning to meet TVA's mission of providing reliable, low-cost energy to the residents of the Tennessee Valley.

After evaluating both the NDC and ELCC methods to determine solar and wind capacity, study results indicate that a mixed approach is most suitable.

Peak capacity contribution of wind varies greatly from year to year. Thus, NDC is the preferred method because it considers every year of historical performance to determine capacity contribution, whereas ELCC only looks at the years of loss-of-load expectation due to high load or low plant availability. Using the NDC approach, wind capacity at peak would be valued at 14 percent in summer and 31 percent in winter. This result is similar to the results from a 2016 MISO study that evaluated dependable capacity of wind from a similar geographic region at a similar level of penetration.

As solar generation at the summer and winter peaks tends to be fairly consistent year to year, ELCC is the preferred method for solar peak capacity contribution. Using the ELCC approach, solar capacity at peak would be valued at 68 percent in summer and 0 percent in winter. The study found contribution to winter peak, typically around 7 a.m., to be less than 1 percent. Increasing solar penetration typically shifts the summer peak and reduces ELCC, as has occurred in regions with higher solar penetration, and future ELCC studies will be able to capture this impact.

#### D.3.5.2 Integration Costs

Study results for solar and wind integration costs at additional penetration levels are summarized in Figure D-6. The results also show the breakdown between additional operating and maintenance costs.

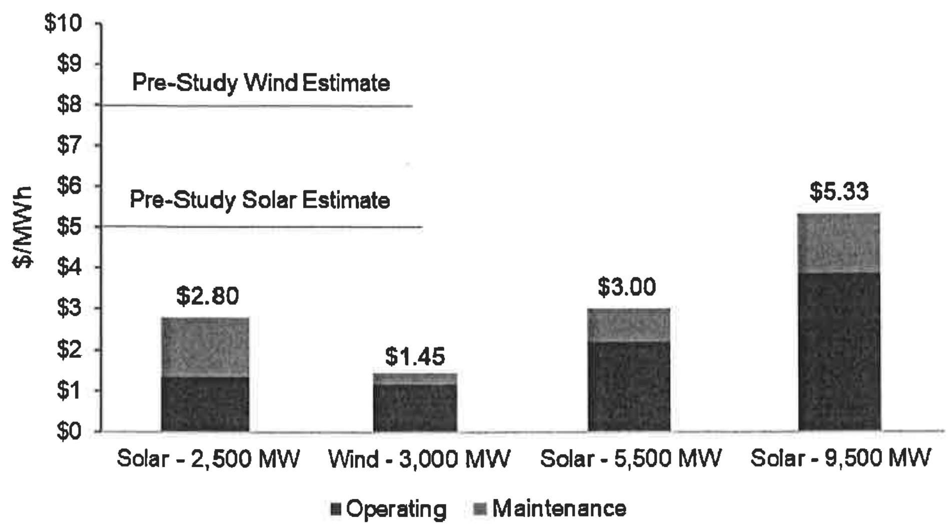



**Figure D-6: Integration Costs at Additional Solar and Wind Penetration Levels.**

Results overall were notably lower than pre-study estimates. Projected solar integration costs averaged about $3/MWh from 2,500 MW to 5,500 MW penetration, then began increasing up to about $5.5/MWh at 9,500 MW penetration. Projected wind integration costs were about $1.5/MWh at 3,000 MW additional penetration. With the diversity of the portfolio, including the ability to leverage the flexibility of conventional hydro assets, the TVA system is well positioned to absorb up to 5,500 MW of solar and 3,000 MW of wind at relatively small additional cost.

#### D.3.5.3 Peer Comparisons

Other utilities and Independent System Operators have conducted studies to evaluate the challenges and costs associated with integrating renewable resources. One of the most comprehensive studies was performed by Synapse in 2015. Synapse researched integration costs and found that system operators implemented measures to integrate large amounts of wind and solar resources at costs generally less than $5/MWh of energy produced. At the time of this publication, more information about the Synapse study was available on the Synapse website at the following link:

http://www.synapse-energy.com/sites/default/files/Costs-of-Integrating-Renewables.pdf

Integration costs are only a piece of the equation, and other factors such as state renewable mandates or goals, declining solar prices, regional capacity factors, cost of competing resources, and consumer demand are playing into resource selection and timing. Understanding the impacts of intermittency also informs the need for flexible resources to support successful integration of renewables.

### D.3.6 Conclusion

Based on study results, summer and winter net dependable capacities of 68 percent and 0 percent for solar and 14 percent and 31 percent for wind will be used. Given TVA's system is well-positioned to absorb up to 5,500 MW of solar and 3,000 MW of wind and current projections are within those bounds for the next decade, study results from those penetration levels informed the recommendation. Sub-hourly integration cost results were rounded to $3/MWh for solar and $2/MWh for wind for use as inputs in resource planning. These planning factors account for the contribution of solar and wind at TVA's summer and winter peaks and for the sub-hourly costs of intermittency that can be captured in TVA's hourly resource planning models.

Identifying net dependable capacities and sub-hourly integration costs for solar and wind resources provides a fuller picture of the operating characteristics of intermittent resources to inform resource selection. The following section further explores the relationship between increasing penetration of intermittent resources and the value of more flexible resources on TVA's system. The NDCs and integration costs are being used in the 2019 IRP as well as in annual resource planning. TVA expects to update the Intermittent Resources Study before the next IRP or as changes in drivers (including intermittent resource penetration) warrant.

## D.4 Flexibility Study

### D.4.1 Purpose

The purpose of the Flexibility Study was to understand the potential benefits of adding more flexible resources on the system and how those benefits may change as renewable penetration increases. The study sought to identify the sub-hourly impacts of introducing highly flexible resources to the portfolio at various levels of intermittent resource penetration. Study results can be applied in hourly capacity planning models to more fully reflect the impacts of adding more flexible resources to the portfolio.

### D.4.2 Background

The Intermittent Resources Study and Flexibility Study go hand in hand, in that they reflect two sides of the same equation. While intermittent resources introduce additional sub-hourly variability in operations, highly flexible resources introduce additional sub-hourly flexibility in operations. Over the next decade, TVA expects to see more solar on the system, both behind and in front of the wholesale meter. It is important to understand the full value that highly flexible resources can offer now and in the future so that value can be proactively considered in capacity planning.

### D.4.3 Study Scope and Approach

This study evaluated the benefit of highly flexible resources, specifically aero-derivative combustion turbines and lithium-ion batteries, with increased solar generation in TVA's system. Specifically, this study sought to:

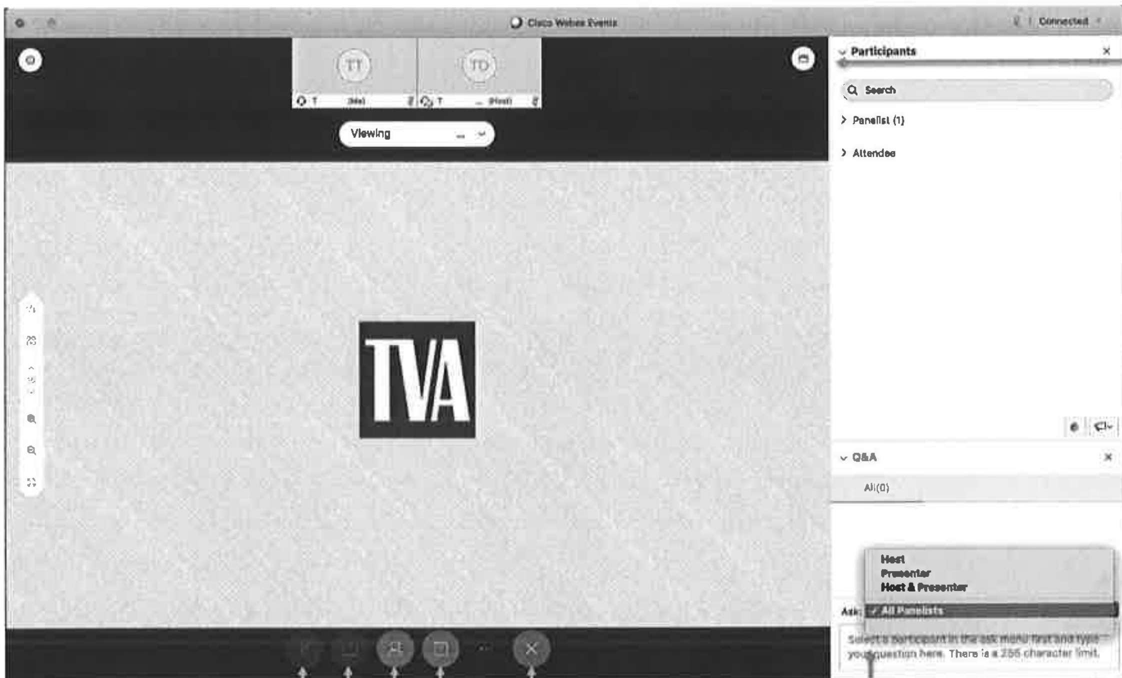
- Identify sub-hourly flexibility benefits of adding aero-derivatives, batteries, hydro and pumped storage to the portfolio at varying levels of penetration
- Determine how this benefit changes at differing solar penetration levels.

This first step involved determining a set of operating parameters for aero-derivatives, batteries, hydro and pumped storage. Figure D-7 highlights study assumptions about aero-derivatives relative to frame combustion turbines (CTs), currently the most flexible resource in TVA's portfolio. Compared to frame CTs,

# EXHIBIT 8

# TVA Renewable Energy

August 21, 2020




To change the view, select icon. In Thumbnail view (1 default), the focus shifts to the shared content when someone starts sharing. The Side-by-Side View (2 middle selection) allows you to view the shared content next to videos of presenters.

1 2

Exit event

Mute

Ask a question

Share (disabled)

Participants

Q&A: When available, ask a question here and direct to All Panelists or an individual.

# Disasters Don't Wait.
# Make Your Plan Today.

Week 1: September 1-5
Make a Plan

Week 2: September 6-12
Build a Kit

Week 3: September 13-19
Prepare for Disasters

Week 4: September 20-26
Teach Youth About Preparedness

https://www.ready.gov/september

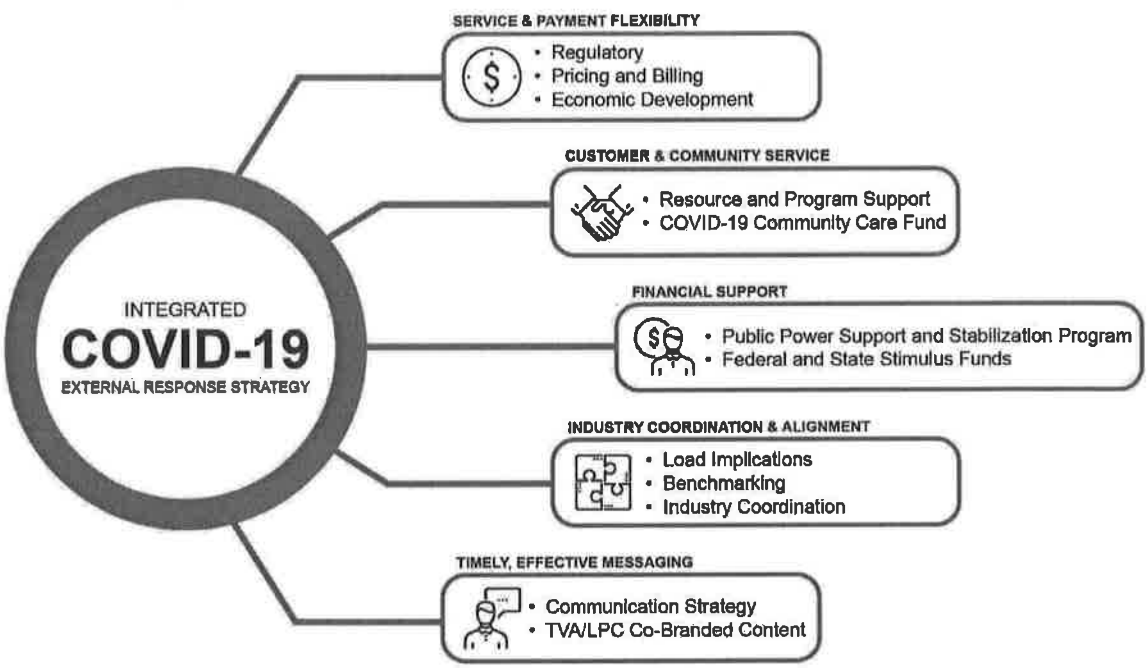
# Agenda

- OPENING
  Debbie Murray
- WELCOME
  Chris Hansen
- GREEN CONNECT
  Ethan Ogle
- DISPERSED POWER PRODUCTION
  Ethan Ogle
- GREEN SWITCH & FLEX
  Ethan Ogle
- GREEN INVEST
  Jamie Bach
- FLEXIBILITY OPTION
  Jamie Bach
- RENEWABLE INTEGRATION
  Aaron Melda
- Q&A

TVA

# WELCOME

CHRIS HANSEN


INTEGRATED
COVID-19
EXTERNAL RESPONSE STRATEGY
SERVICE & PAYMENT FLEXIBILITY
• Regulatory
• Pricing and Billing
• Economic Development
CUSTOMER & COMMUNITY SERVICE
• Resource and Program Support
• COVID-19 Community Care Fund
FINANCIAL SUPPORT
• Public Power Support and Stabilization Program
• Federal and State Stimulus Funds
INDUSTRY COORDINATION & ALIGNMENT
• Load Implications
• Benchmarking
• Industry Coordination
TIMELY, EFFECTIVE MESSAGING
• Communication Strategy
• TVA/LPC Co-Branded Content

TVA

AUGUST 2020

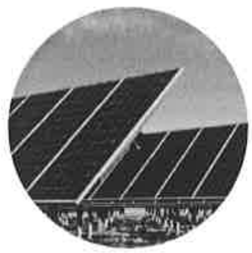
We have a variety of renewable programs that align to the vast interests of our customers.

TVA Green
renewables@tva.gov

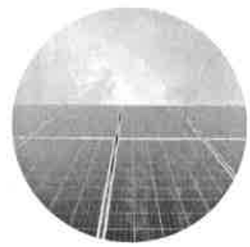
TVA Green

# Renewable Solutions

Green Connect



Dispersed Power Production



Green Switch

Green Flex

Green Invest

Flexibility Option

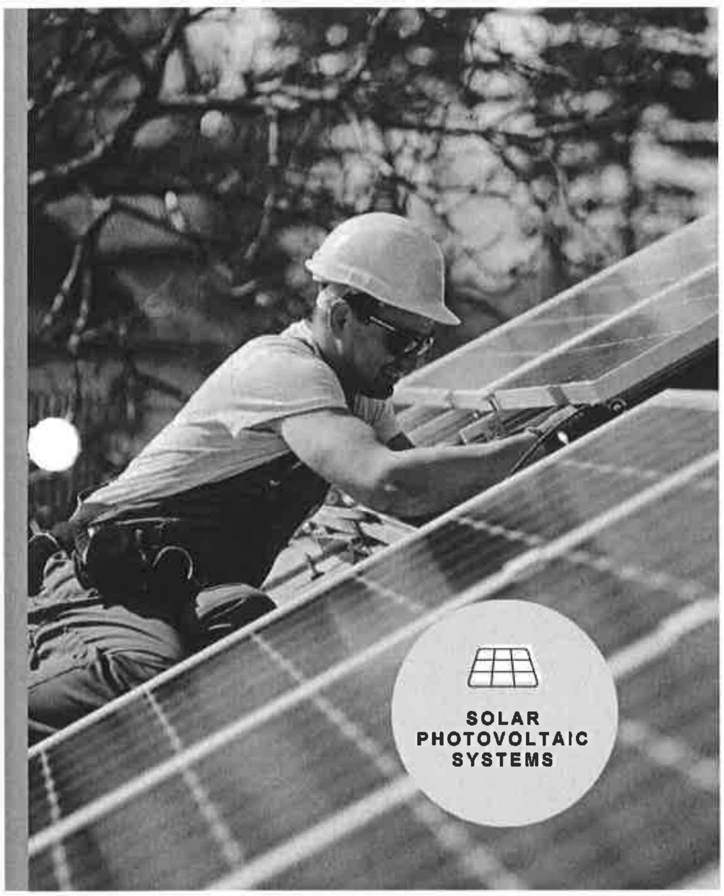
Green

**COMING JANUARY 2021**

# GREEN CONNECT

TVA GREEN

TVA Green




GREEN CONNECT

# Program benefits

**FOR INSTALLERS**

- Increased standardization
- Customer leads
- Green Connect contact center

**FOR CUSTOMERS**

- Access to quality solar installers
- Educational resources
- Installation verifications

TVA Green

GREEN CONNECT

# Customer portal

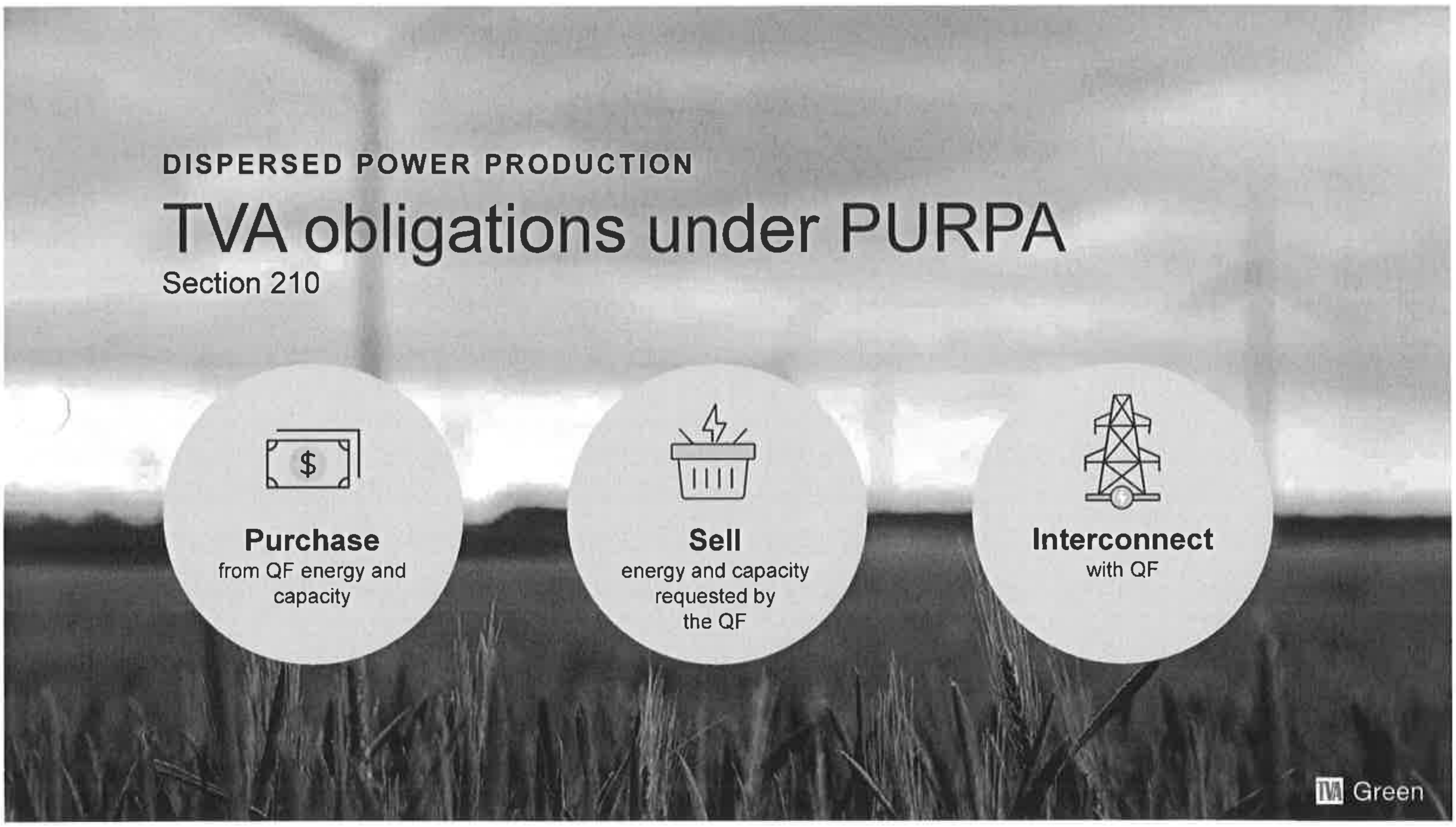

## GREEN CONNECT

# Installer portal

# DISPERSED POWER PRODUCTION

TVA GREEN

TVA Green

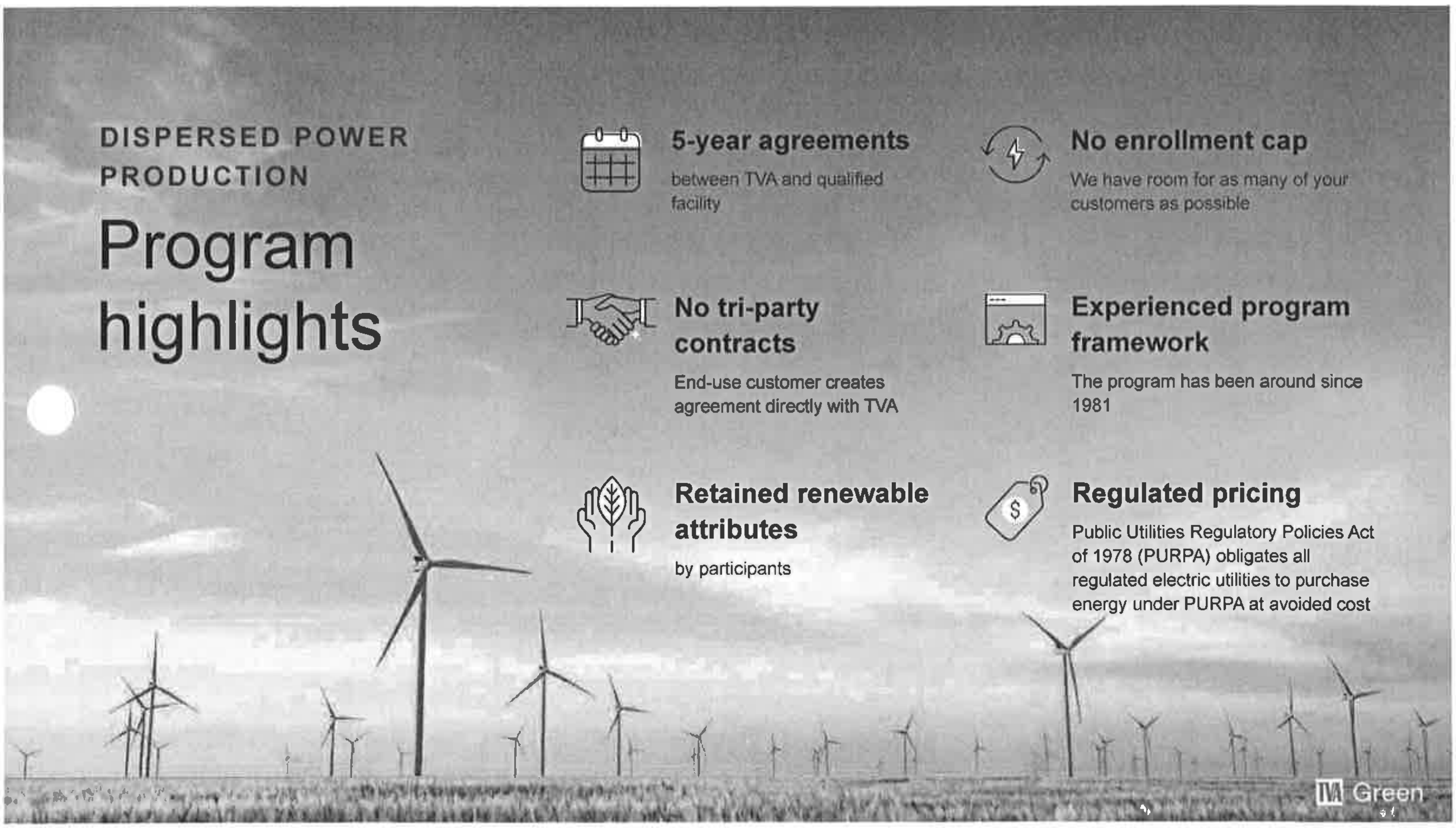

DISPERSED POWER PRODUCTION
TVA obligations under PURPA
Section 210
Purchase
from QF energy and capacity
Sell
energy and capacity requested by the QF
Interconnect
with QF
TVA Green

**DISPERSED POWER PRODUCTION**

A program that allows residential, business and industry customers to **sell power from qualified facilities** to TVA.

SOLAR WIND BIOMASS WASTE GEOTHERMAL

Green


DISPERSED POWER PRODUCTION
Program highlights
5-year agreements
between TVA and qualified facility
No enrollment cap
We have room for as many of your customers as possible
No tri-party contracts
End-use customer creates agreement directly with TVA
Experienced program framework
The program has been around since 1981
Retained renewable attributes
by participants
Regulated pricing
Public Utilities Regulatory Policies Act of 1978 (PURPA) obligates all regulated electric utilities to purchase energy under PURPA at avoided cost
Green

# GREEN SWITCH

TVA GREEN

**GREEN SWITCH**

## Helping residential, business and industrial customers support renewable energy generated **within the Valley.**

**70%**
SOLAR
*GPP Sites*

**20%**
WIND
*Invenergy-Owned Buffalo Mountain Wind Purchase Power Agreement*

**10%**
BIOMASS
*GPP Sites*

TVA Green

GREEN SWITCH COST

Customers purchase renewable energy to match their electricity usage. For as little as $2 per month, they reduce their environmental impact.

A GREEN-E ENERGY CERTIFIED PRODUCT

**$2**

*for a*

200 kWh BLOCK

*through the Green-e Energy certification program*

TVA Green


GREEN SWITCH
Program highlights
No long-term commitment
No contract with participants – they can enroll and un-enroll on a monthly basis
No upfront cost
Payments can be added to your customers monthly utility bill
No infrastructure needed
Your customers do not need any additional infrastructure to get started using renewable energy
For as little as
$2
a month
customers can reduce their environmental impact
TVA Green

# GREEN FLEX

TVA GREEN

TVA Green

## GREEN FLEX

A program that allows businesses and industries inside the Tennessee Valley to purchase **out-of-Valley wind** renewable energy certificates (RECs).

**100%**

WIND

*Sourced from Iowa, Illinois, or Kansas*

TVA Green

GREEN FLEX COST

Customers purchase RECs, the full MWh of renewable energy generated and delivered to the grid, which allow your customers to make renewable claims.

$1.50 per MWH

*through the Green-e Energy certification program*

Energy CERTIFIED — A GREEN-E ENERGY CERTIFIED PRODUCT

TVA Green


GREEN FLEX
Program highlights
1-year
agreement
January – December
Certified
through Green-e,
guaranteeing renewable generation coverage for all purchased RECs
Free
to sign up
and get started with no additional infrastructure needed
2,000
RECs
Annual minimum purchase
Purchase may not exceed
105%
of participant's annual electricity consumption
TVA Green

# GREEN INVEST

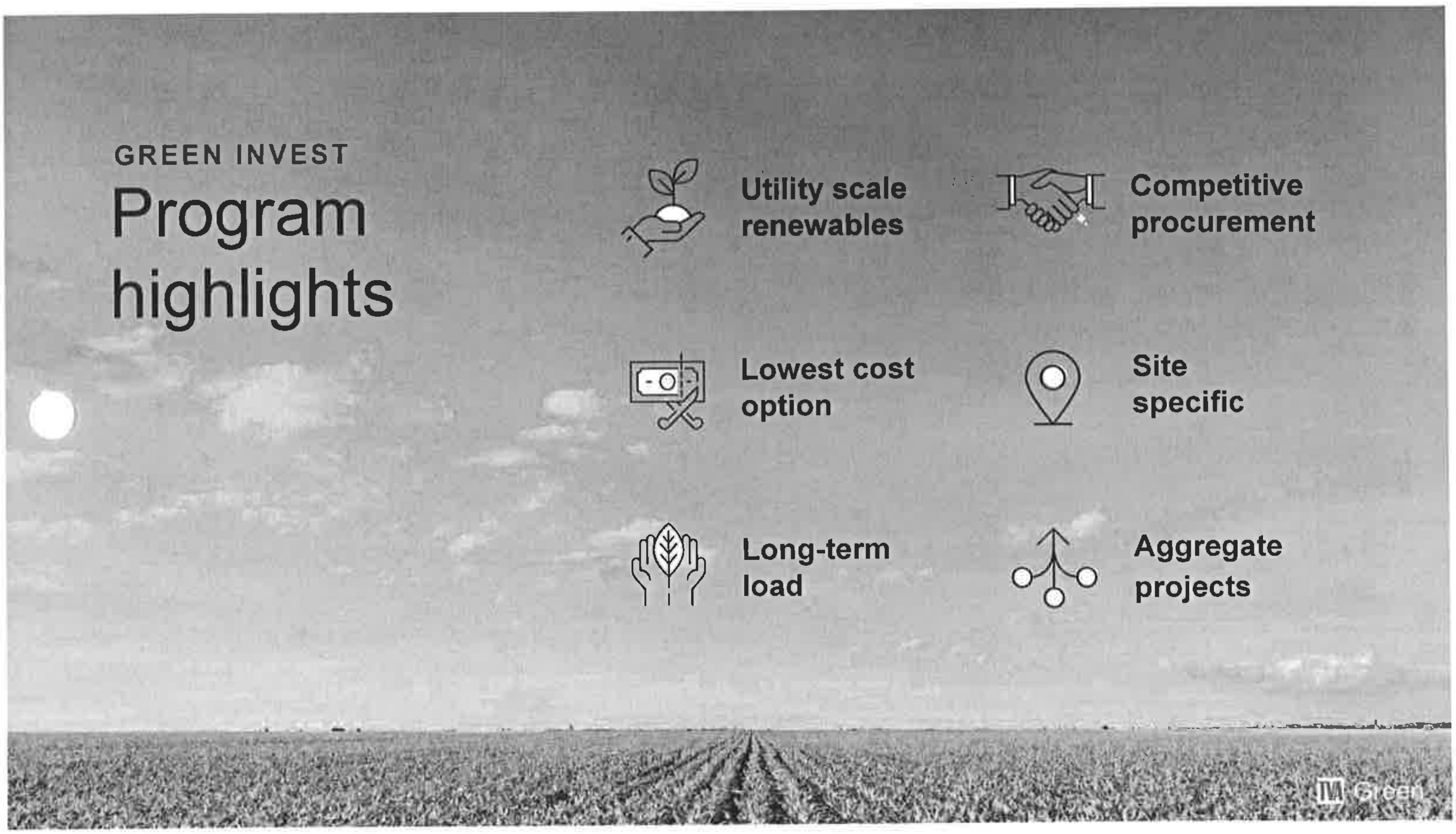
TVA GREEN

**GREEN INVEST**

## Help your end-use customers meet their sustainability goals through partnering with us to bring new, renewable energy to the Tennessee Valley.

**100%**
RENEWABLE

TVA Green


GREEN INVEST
Program highlights
Utility scale renewables
Competitive procurement
Lowest cost option
Site specific
Long-term load
Aggregate projects

# FLEXIBILITY OPTION


FLEX
Valley Partners now have the ability
to provide cleaner, greener power.
TVA VALLEY Partners

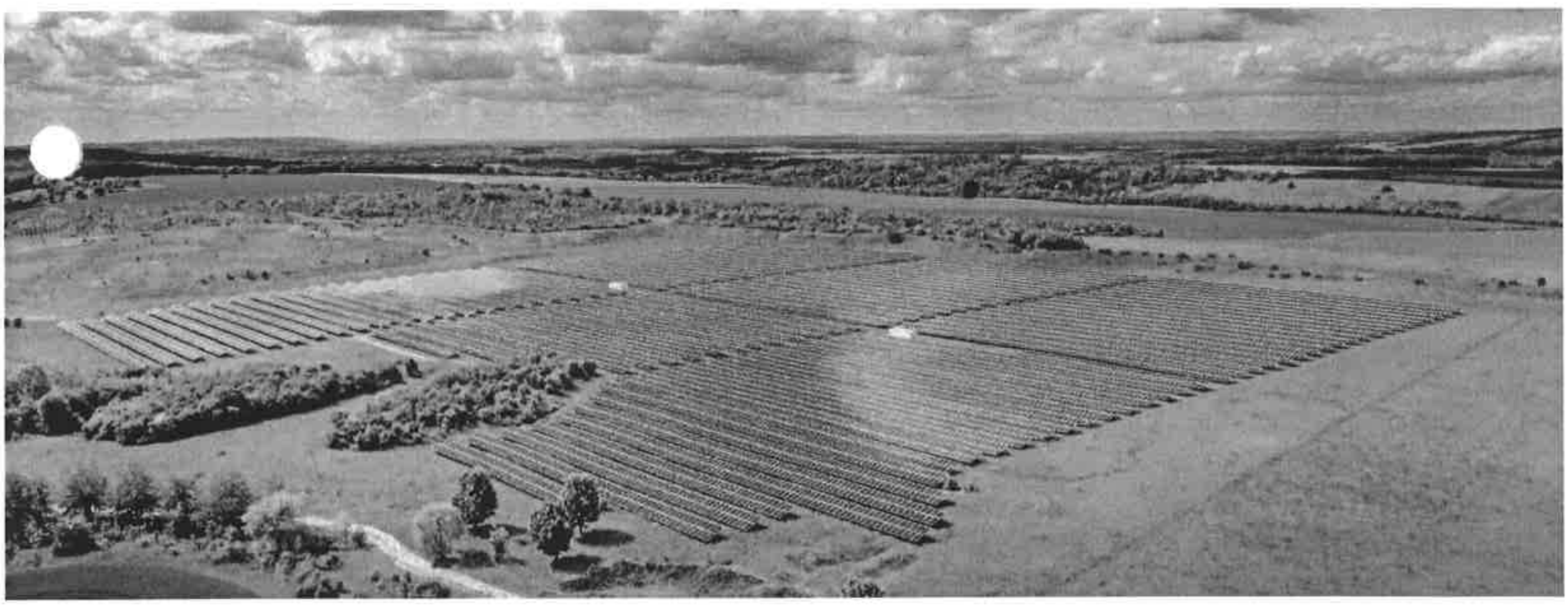

up to
5%
can be locally generated
MINIMUM 1MW
TVA VALLEY Partners


FLEXIBILTY OPTION
Partner benefits
Lowers wholesale bill from TVA
Long-term customer load commitments
Partners with local businesses
Mitigates behind-the-meter threats
Pursues a variety of ownership and operating options (e.g., PPA)
TVA VALLEY Partners

# RENEWABLE INTEGRATION

Aaron Melda

TVA continues to look for ways to efficiently integrate renewable energy into our portfolio, while providing low cost, reliable energy.



# SEEM

Southeast Energy Exchange Market

Exploring a centralized, automated intra-hour energy market with a goal of lowering customer costs and optimizing renewable energy, while maintaining reliable service

# Q&A

LAURA DUNCAN & DEBBIE MURRAY

# Thank you and be safe

TVA Green

QUESTIONS?

www.tvagreen.com

renewables@tva.gov

TVA

# EXHIBIT 9

# COMMUNITY DEVELOPMENT ENTERPRISES
# JACKSON SOLAR MICROGRID
## ROOSEVELT PARKWAY
## JACKSON, MADISON COUNTY, TENNESSEE

**SITE DEVELOPER**
COMMUNITY DEVELOPMENT ENTERPRISES
1104 WHITEHALL STREET
JACKSON TN 38301
PHONE 731-240-5001
CONTACT. DENNIS EMBERLING

**BUILDING & CODES**
CITY OF JACKSON
BUILDING & CODES DEPARTMENT
118 EAST MAIN STREET, SUITE 208
JACKSON, TN 38301
PHONE 731-425-8255
CONTACT GREG ROWLAND

**CIVIL ENGINEER**
L.I. SMITH AND ASSOCIATES
302 N. CALDWELL STREET
PARIS TN 38242
PHONE: 731-644-1014
CONTACT. PATRICK SMITH

**FIRE DEPARTMENT**
CITY OF JACKSON FIRE DEPARTMENT
720 SOUTH HIGHLAND AVENUE
JACKSON TN 38301
PHONE 731-425-8350
CONTACT CHIEF DARRYL SAMUELS

**LAND SURVEYOR**
L.I. SMITH AND ASSOCIATES
302 N. CALDWELL STREET
PARIS TN 38242
PHONE: 731-644-1014
CONTACT: PATRICK SMITH

**SANITARY SEWER DEPT.**
JACKSON ENERGY AUTHORITY
351 MARTIN LUTHER KING JR. DRIVE
JACKSON, TN 38301
PHONE: 731-422-7371

**TELEPHONE**
AT&T
208 SOUTH AKARD STREET
DALLAS TX 75202
PHONE: 800-288-2020

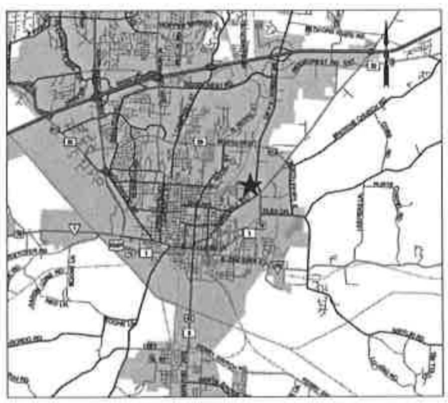
**WATER DEPT.**
JACKSON ENERGY AUTHORITY
351 MARTIN LUTHER KING JR. DRIVE
JACKSON TN 38301
PHONE 731-422-7371

**ELECTRIC**
...N ENERGY AUTHORITY
...LUTHER KING JR. DRIVE
...N 38301
...-422-7371

**NATURAL GAS**
JACKSON ENERGY AUTHORITY
351 MARTIN LUTHER KING JR DRIVE
JACKSON TN 38301
PHONE: 731-422-7371

NOTICE OF COVERAGE HAS BEEN ISSUED FOR A GENERAL CONSTRUCTION PERMIT AND ASSOCIATED GENERAL ARAP PERMIT THROUGH TDEC.

PERMITTED DISTURBANCE 32 ACRES
TDEC PERMIT NUMBERS:
TNR 123460
NR 2102.014



VICINITY MAP - NOT TO SCALE

**SITE DATA**

A. OWNERS OF RECORD. — HUNT PROPERTIES, 1031 GREYSTONE SQUARE, JACKSON, TN 38305 — MORRIS CROCKER, 15 SUTTON PLACE, JACKSON, TN 38305

DEVELOPER — COMMUNITY DEVELOPMENT ENTERPRISES, 1104 WHITEHALL STREET, JACKSON TN 38301

B. SOURCE OF TITLE — BOOK 733 PAGE 731 AND BOOK 257, PAGE 456; TAX MAP 65, PARCEL 103.00 AND 104.00

CITY OF JACKSON, MADISON COUNTY, TENNESSEE

SITE AREA = +/- 32 ACRES
TOTAL AREA = +/- 34.27 ACRES

C. THE SITE IS LOCATED IN UNSHADED FLOOD ZONE "X", AREAS DETERMINED TO BE OUTSIDE THE 0.2% ANNUAL CHANCE FLOODPLAIN AS DETERMINED BY THE NATIONAL FLOOD INSURANCE PROGRAM FLOOD INSURANCE RATE MAP NO. 47113C0164E, DATED AUGUST 03, 2009.

**PLANNING INFORMATION**

A. ZONING DESIGNATION — GENERAL RESIDENTIAL DISTRICT
FRONT SETBACK: 25 FEET
SIDE SETBACK: 8 FEET
REAR SETBACK: 10 FEET

B. INTENDED USE — SOLAR MICROGRID

C. PARKING — NONE REQUIRED FOR INTENDED USE
REQUIRED — 0 SPACES
PROPOSED — 0 SPACES

| SHEET NO. | SHEET NAME | SCALE |
|---|---|---|
| C-000 | COVER SHEET | |
| C-001 | NOTES | |
| C-100 | EXISTING | 1"=100' |
| C-101 | VEGETATIVE IMPACT EVAL. | 1"=100' |
| C-200 | LAYOUT | 1"=100' |
| C-201 | LANDSCAPING | 1"=100' |
| C-300 | GRADING | 1"=100' |
| C-400 | E.P.S.C. PHASE 1 | 1"=100' |
| C-401 | E.P.S.C. PHASE 2 | 1"=100' |
| C-402 | E.P.S.C. PHASE 3 | 1"=100' |
| C-403 | A.R.A.P. | 1"= 30' |
| C-404 | E.P.S.C. PHASE 4 | 1"=100' |
| C-800 | DETAILS | |
| C-801 | DETAILS | |
| C-802 | DETAILS | |
| C-803 | DETAILS | |
| C-804 | DETAILS | |

**Ownership and Quality of Construction**
CERTIFICATE OF QUALITY OF CONSTRUCTION
Date — Owner/Developer

**Sanitary Sewerage Systems**
CERTIFICATE OF APPROVAL OF SANITARY SEWERAGE SYSTEMS
Date — Jackson Energy Authority

**Engineering Certification**
CERTIFICATE OF ACCURACY OF DESIGN
Date — Registered Engineer, Tennessee Certificate No.

**Streets and Street Drainage**
CERTIFICATE OF APPROVAL OF STREETS AND STORM DRAINAGE
Date — City of Jackson Engineering Department

**Public Water Systems**
CERTIFICATE OF APPROVAL OF WATER SYSTEMS
Date — Jackson Energy Authority

**Construction Drawing Approval**
CERTIFICATE OF CONSTRUCTION DRAWING APPROVAL
Date — Jackson Municipal Regional Planning Commission

L.I. Smith and Associates, Inc.
LAND DEVELOPMENT | INFRASTRUCTURE DESIGN
— SURVEYING SERVICES —
302 North Caldwell Street, Paris, TN 38242 | 731-644-1014 | www.lismith.com
475 Metroplex Drive, Suite 212 Nashville, TN 37211 | 615-256-0290

SHEET: COVER — NUMBER: C-000
REVISIONS

CITY OF JACKSON ENGINEERING DEPARTMENT

GENERAL CONSTRUCTION NOTES

1. THE CONTRACTOR SHALL NOTIFY THE CITY OF JACKSON BEFORE COMMENCING CONSTRUCTION.

2. THE CONTRACTOR SHALL BE RESPONSIBLE FOR NOTIFYING ANY UTILITY COMPANY, WHICH MAINTAINS A UTILITY LINE WITHIN THE BOUNDARIES OF THE PROJECT BEFORE THE INITIATION OF ANY CONSTRUCTION ON THE PROJECT OR IN THE STREETS BORDERING THE PROJECT.

3. BEFORE ANY GRADING IS STARTED, THE DEVELOPER/CONTRACTOR MUST OBTAIN A DEVELOPMENT PERMIT FROM THE CITY OF JACKSON.

4. ALL CONSTRUCTION SHALL MEET THE CITY OF JACKSON STANDARD SPECIFICATIONS CONTAINED WITHIN THE SUBDIVISION AND LAND DEVELOPMENT REGULATIONS.

5. THE CONTRACTOR MUST HAVE WRITTEN APPROVAL FROM THE CITY OF JACKSON ENGINEER AND THE PROJECT ENGINEER BEFORE ANY CHANGE IN DESIGN IS MADE.

6. ALL CONSTRUCTION SHALL BE TESTED BY A LICENSED INDEPENDENT MATERIAL TESTING COMPANY TO ENSURE COMPLIANCE WITH COMPACTION REQUIREMENTS AND TO ENSURE THE MINIMUM THICKNESS OF BASE AND PAVEMENT. A COPY OF THE TEST RESULTS SHALL BE FORWARDED TO THE CITY OF JACKSON AND LABELED AS TEST REPORTS "SUBDIVISION NAME", JACKSON, TENNESSEE.

7. ALL SOIL FILL AREAS IN THE STREET SHALL BE COMPACTED TO 95% OF STANDARD PROCTOR DENSITY, TESTED PER ASTM D-698. THE TOP SIX INCHES OF ALL FILLS AND CUT AREAS IN THE STREET SHALL BE COMPACTED TO 100% OF STANDARD PROCTOR DENSITY PER ASTM D-698.

8. FILLS SHALL BE CONSTRUCTED IN LIFTS WITH A MAXIMUM LOOSE LIFT THICKNESS OF EIGHT (8) INCHES.

9. SUBGRADE COMPACTION TESTING MUST BE COMPLETED AFTER INSTALLATION OF ALL UTILITIES IN THE STREET AND IMMEDIATELY PRECEDING BASE MATERIAL APPLICATION. THE SUBGRADE COMPACTION TEST RESULTS MUST BE SUBMITTED TO AND APPROVED BY THE CITY ENGINEER'S OFFICE PRIOR TO THE APPLICATION OF THE BASE MATERIAL. BASE MATERIAL COMPACTION TESTING MUST BE COMPLETED IMMEDIATELY PRECEDING THE APPLICATION OF THE BINDER COAT. THE BASE MATERIAL TEST RESULTS MUST BE SUBMITTED TO AND APPROVED BY THE CITY ENGINEER'S OFFICE PRIOR TO THE APPLICATION OF THE BINDER COAT. THE BINDER COAT COMPACTION AND THICKNESS TEST RESULTS MUST BE SUBMITTED TO AND APPROVED BY THE CITY ENGINEER'S OFFICE PRIOR TO THE APPROVAL OF THE FINAL PLAT. ALL STORM DRAIN AND OTHER UTILITIES LOCATED UNDER THE STREETS SHALL HAVE TRENCHES COMPACTED AT 95% STANDARD PROCTOR DENSITY PER ASTM D-698.

10. THE MINIMUM FREQUENCY OF SOIL TESTS SHALL BE ONE TEST PER [illegible] FEET OF STREET LENGTH WITH A MINIMUM OF THREE (3) TESTS PER PROJECT PHASE. TESTING SHALL BE PERFORMED AT THE ABOVE FREQUENCY ON EACH TEN (10) INCH LIFT OF FILLS AND ON THE FINAL SUBGRADE WHETHER IN CUT OR FILL.

11. PRIOR TO PLACING GRANULAR BASE ON THE STREET THE SUBGRADE SHALL BE PROOF ROLLED WITH A LOADED DUMP TRUCK WITH A GROSS WEIGHT OF APPROXIMATELY 30 TONS IN THE PRESENCE OF THE CITY

ENGINEER OR HIS DESIGNEE. NOTIFY THE CITY ENGINEER A MINIMUM OF TWO WORKING DAYS IN ADVANCE FOR SCHEDULING.

12. ROADWAY BASE SHALL BE COMPACTED TO A MINIMUM DENSITY OF 98% STANDARD PROCTOR DENSITY (ASTM D-698).

13. THE GRANULAR BASE SHALL BE TESTED FOR DENSITY AND THICKNESS EVERY [illegible] FEET OF STREET LENGTH WITH A MINIMUM OF THREE (3) TESTS PER PROJECT PHASE.

14. PRIOR TO PLACING ASPHALT ON THE STREET THE GRANULAR BASE SHALL BE PROOF ROLLED WITH A LOADED DUMP TRUCK WITH A GROSS WEIGHT OF APPROXIMATELY 30 TONS IN THE PRESENCE OF THE CITY ENGINEER OR HIS DESIGNEE. NOTIFY THE CITY ENGINEER A MINIMUM OF TWO WORKING DAYS IN ADVANCE FOR SCHEDULING.

15. ALL ASPHALTIC COURSES SHALL BE COMPACTED TO A MINIMUM OF 92% OF MAXIMUM THEORETICAL DENSITY.

16. ASPHALT SHALL BE RANDOMLY TESTED FOR DENSITY AND THICKNESS EVERY 300 FEET OF STREET LENGTH WITH A MINIMUM OF THREE (3) TESTS PER PROJECT PHASE.

17. CONCRETE FOR CURB AND GUTTER AND SIDEWALK SHALL BE A MINIMUM 3000 PSI AT 28 DAYS AND SHALL BE TESTED FOR CONSISTENCY AND STRENGTH IN ACCORDANCE WITH AASHTO TEST METHODS T 119, T 22 AND T 23. THE TESTS SHALL BE PERFORMED EVERY 600 FEET OF STREET LENGTH WITH A MINIMUM OF ONE (1) TEST PER DAY.

18. TYPE, USE AND LOCATION OR ORNAMENTAL STREET SIGNS AND SIGNPOSTS MUST BE APPROVED BY THE CITY OF JACKSON ENGINEERING DEPARTMENT PRIOR TO SUBMISSION OF THE FINAL PLAT.

19. ADJUST MANHOLE LIDS TO MATCH GRADE OF CROSS-SLOPE IF OFFSET FROM CENTERLINE. ALL MANHOLE LIDS TO BE FLUSH WITH BASE LAYER OF PAVEMENT THEN ADJUSTED AS REQUIRED BY CONTRACTOR WITH FINAL PAVEMENT LAYER INSTALLATION.

20. ALL STREETS ADJACENT TO THE SITE SHALL BE KEPT CLEAN DURING CONSTRUCTION.

21. TRAFFIC CONTROL SHALL BE PROVIDED AS APPROPRIATE AND SHALL BE IN ACCORDANCE WITH THE CURRENT EDITION OF THE MANUAL ON UNIFORM TRAFFIC CONTROL DEVICES.

GRADING & DRAINAGE NOTES

1. CONTRACTOR SHALL VERIFY EXISTING ELEVATIONS PRIOR TO BEGINNING WORK.

2. CONTOUR LINES AND SPOT ELEVATIONS ARE THE RESULT OF A DETAILED ENGINEERING GRADING DESIGN AND REFLECT A PLANNED INTENT WITH REGARD TO DRAINAGE AND MOVEMENT OF MATERIALS. SHOULD THE CONTRACTOR HAVE ANY QUESTION OF THE INTENT OR ANY PROBLEMS WITH CONTINUITY OF GRADES, THE ENGINEER SHOULD BE CONTACTED IMMEDIATELY PRIOR TO BEGINNING WORK.

3. CONTRACTOR SHALL REFER TO AND ADHERE TO THE RECOMMENDATIONS IN THE GEOTECHNICAL ENGINEERING REPORT, IF AVAILABLE.

4. ALL TRENCHING, PIPE LAYING, AND BACKFILLING SHALL BE IN ACCORDANCE WITH FEDERAL OSHA REGULATIONS.

5. ANY RETAINING WALLS REQUIRED SHALL BE BY DESIGN/BUILD AND MUST BE DESIGNED AND SEALED BY AN ENGINEER LICENSED IN THE STATE OF TENNESSEE AND SUBMITTED FOR REVIEW AND APPROVAL PRIOR TO ISSUANCE OF A PERMIT. REFER TO THE VENDOR'S PLANS FOR RETAINING WALL AND RAILING DETAILS. GUARDS (42" HIGH) SHALL BE PROVIDED FOR ALL RETAINING WALLS WHERE DROPS ARE EQUAL TO OR EXCEED 30 INCHES IN HEIGHT, IN ACCORDANCE WITH APPLICABLE CODES.

EROSION CONTROL NOTES

1. THE CONTRACTOR SHALL PROVIDE AND MAINTAIN EROSION CONTROL DURING CONSTRUCTION AS REQUIRED BY THE CITY OF JACKSON RULES AND REGULATIONS FOR CONTROL OF EROSION AND STORMWATER AND THE LATEST EDITION OF THE TENNESSEE EROSION AND SEDIMENT CONTROL HANDBOOK TO PREVENT SITUATION DOWNSTREAM IN ANY DITCHES, PIPES, DRAINAGE STRUCTURES, STREETS, OR ADJACENT PROPERTIES.

2. ADDITIONAL EROSION CONTROL MEASURES MAY BE NECESSARY AS WORK PROGRESSES. THE CONTRACTOR SHALL BE RESPONSIBLE FOR MAINTAINING AND ADJUSTING THE EROSION CONTROL MEASURES AS NECESSARY THROUGHOUT THE LIFE OF CONSTRUCTION AND UNTIL FULL STABILIZATION OF THE AREA IS ACHIEVED.

3. ALL TEMPORARY EROSION CONTROL MEASURES MUST BE IN PLACE BEFORE BEGINNING EARTH-MOVING OPERATIONS. AREAS OF EXPOSED EARTH SHALL BE KEPT TO A MINIMUM. EMBANKMENTS AND EXCAVATED AREAS SHALL BE PROMPTLY STABILIZED TO MINIMIZE EROSION.

4. THE CONTRACTOR OR OWNER SHALL FILE ALL DOCUMENTS NECESSARY FOR RECEIVING A NPDES PERMIT WHEN REQUIRED FOR STORMWATER DISCHARGE (FILING THE N.O.I. INCLUDING PAYMENT OF PERMIT FEES), IMPLEMENT AN EFFECTIVE EROSION PLAN, DOCUMENT THE EFFECTIVENESS OF THE PLAN AND ADJUST THE PLAN AS NECESSARY TO COMPLY WITH THE CONDITIONS OF THE PERMIT. THIS PLAN SHALL BE REVISED AS NECESSARY AND SHALL BE MADE A PART OF THE STORMWATER POLLUTION PREVENTION PLAN. ALL PROPOSED REVISIONS SHALL BE IN CONSULTATION WITH THE DESIGN ENGINEER.

5. ALL EXCAVATION AND FILL ACTIVITIES MUST BE CONDUCTED IN THE DRY.

6. CHECK DAMS SHALL BE INSTALLED IN THE TOE OF ALL FILL SLOPES, IN DITCHES, AND OTHER AREAS AS NECESSARY TO PREVENT SILTS FROM ENTERING ADJACENT PROPERTIES. ALL BALED STRAW SHALL BE REPLACED AT 60-DAY MINIMUM INTERVALS, UNTIL FULL STABILIZATION IS ACHIEVED.

7. ANY STOCKPILED SOILS FOR FILL MATERIAL SHALL BE LOCATED AND TREATED IN A MANNER TO PREVENT SILT FROM LEAVING THE PROPERTY EITHER THROUGH STORM DRAINS OR OVER LAND.

8. CONTRACTOR SHALL MAINTAIN A RAIN GAGE ON SITE AT ALL TIMES AND RECORD RAINFALL DAILY. CONTRACTOR MUST INSPECT EROSION CONTROL TWICE PER CALENDAR WEEK. INSPECTIONS MUST TAKE PLACE AT LEAST 72 HOURS APART.

9. ALL AREAS SHALL BE SEEDED AND MULCHED AT MINIMUM. STABILIZING MATERIALS SHALL BE APPLIED AS SOON AS POSSIBLE UPON COMPLETION OF FINAL GRADING AND IN NO CASE GREATER THAN 15 DAYS.

10. AFTER FULL STABILIZATION OF ALL DISTURBED AREAS THE CONTRACTOR SHALL REMOVE ALL TEMPORARY EROSION CONTROL ITEMS. AFTER FULL STABILIZATION THE CONTRACTOR SHALL FILE A "NOTICE OF TERMINATION" WITH THE STATE OF TENNESSEE.

11. WHERE EARTH-DISTURBING ACTIVITY HAS BEEN TEMPORARILY CEASED, TEMPORARY STABILIZATION WILL BE APPLIED WITHIN (7) SEVEN DAYS IF THE ACTIVITY WILL NOT RESUME WITHIN (15) FIFTEEN DAYS.

12. THE DEVELOPER OR ANY DESIGNEE PERFORMING CONSTRUCTION ACTIVITIES ON HIS BEHALF IS RESPONSIBLE FOR COMPLYING WITH APPLICABLE STATE AND FEDERAL REGULATIONS WITH REGARD TO SEDIMENT/EROSION CONTROL.

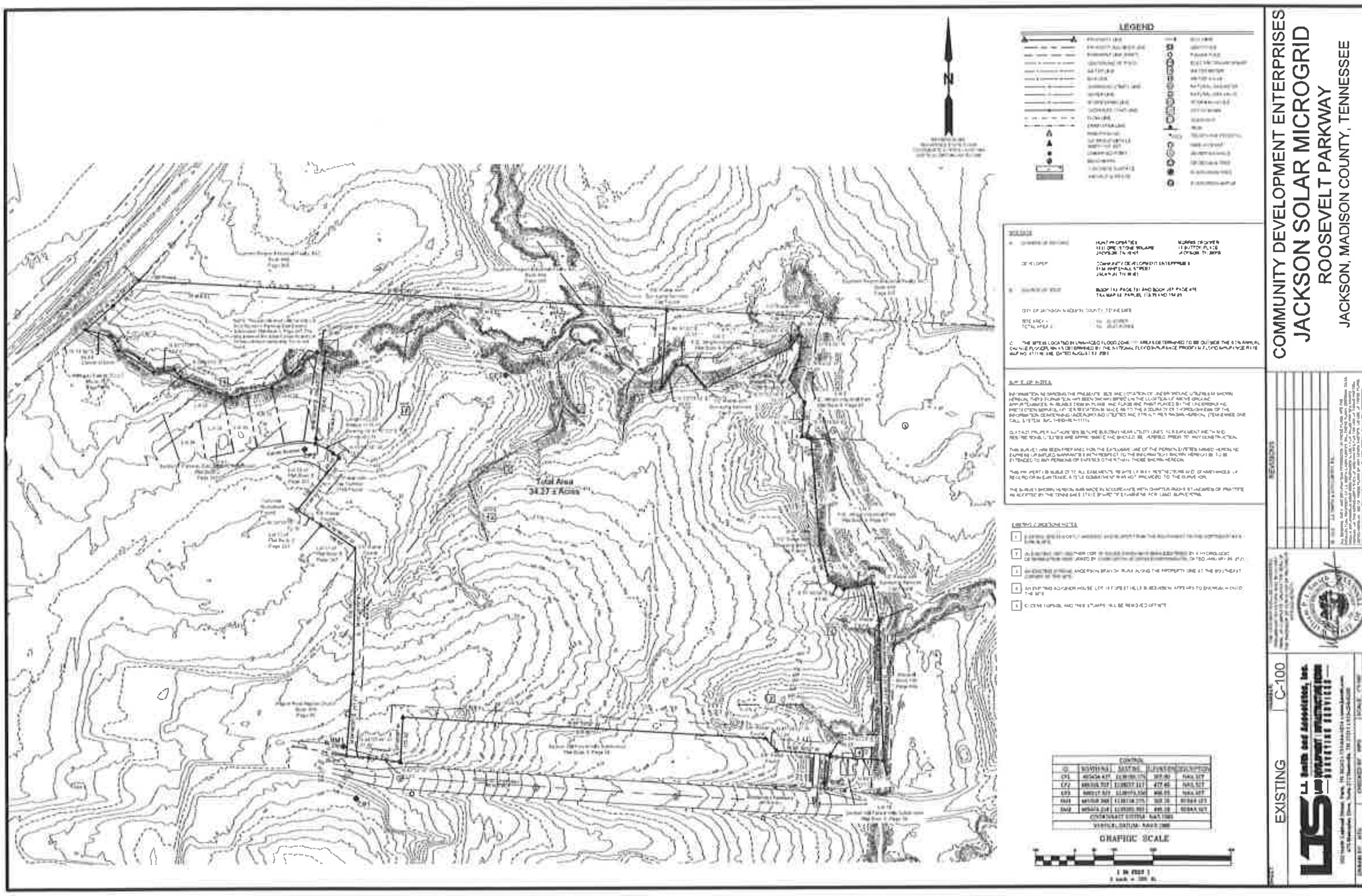
COMMUNITY DEVELOPMENT ENTERPRISES
JACKSON SOLAR MICROGRID
ROOSEVELT PARKWAY
JACKSON, MADISON COUNTY, TENNESSEE

REVISIONS

NOTES

C-001

LJ Smith and Associates, Inc.

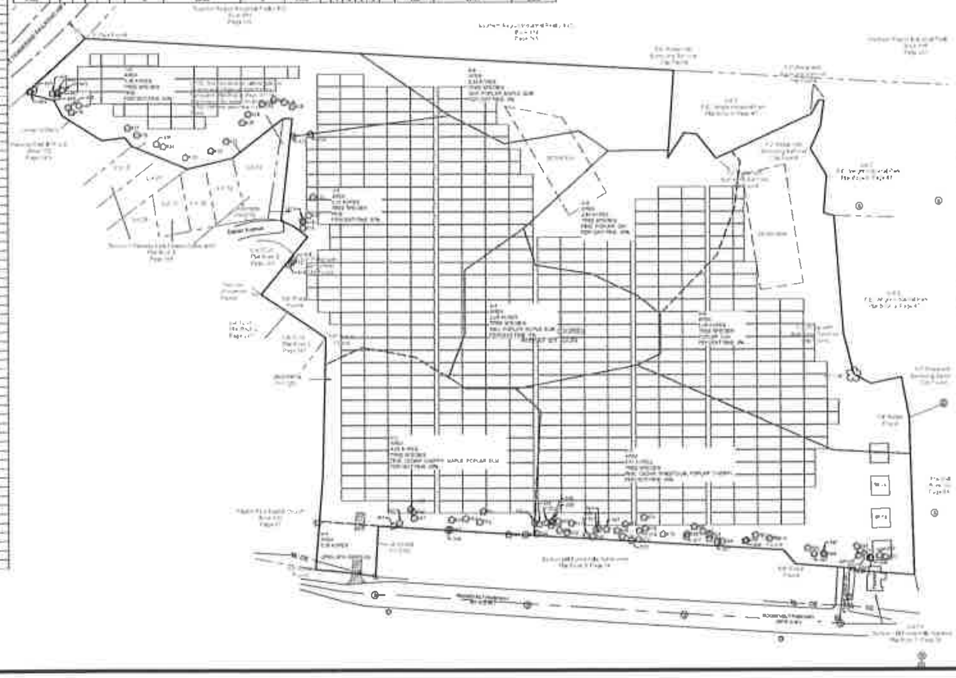

LEGEND
N
Total Area
COMMUNITY DEVELOPMENT ENTERPRISES
JACKSON SOLAR MICROGRID
ROOSEVELT PARKWAY
JACKSON, MADISON COUNTY, TENNESSEE
REVISIONS
EXISTING
C-100
CONTROL
GRAPHIC SCALE

# COMMUNITY DEVELOPMENT ENTERPRISES
# JACKSON SOLAR MICROGRID
## ROOSEVELT PARKWAY
## JACKSON, MADISON COUNTY, TENNESSEE

VEGETATIVE IMPACT EVALUATION

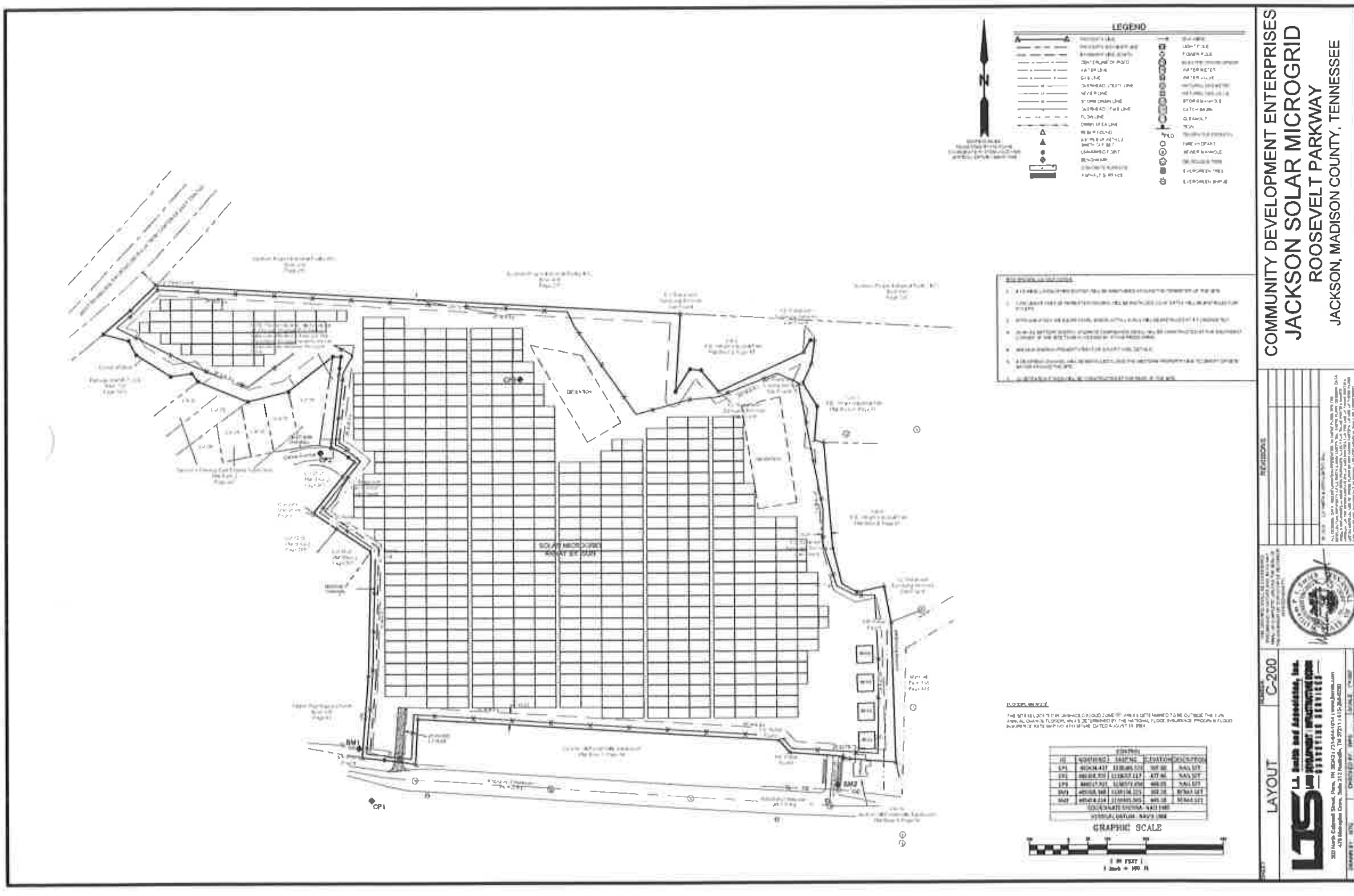
C-101

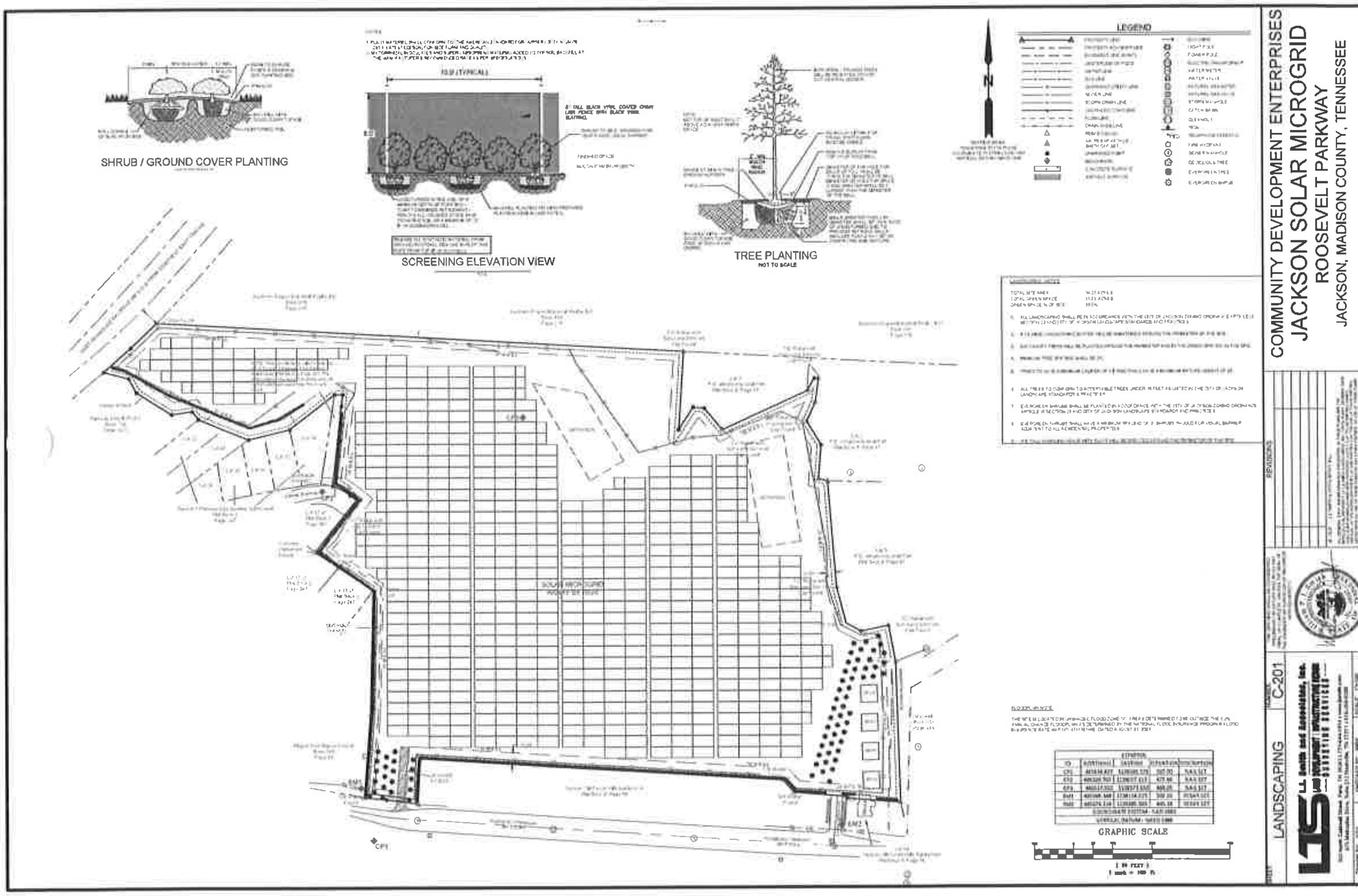
LEGEND



GRAPHIC SCALE

( IN FEET )


LEGEND
N
SOLAR MICROGRID
DETENTION
CP1
CP3
BM1
BM2
GRAPHIC SCALE
COMMUNITY DEVELOPMENT ENTERPRISES
JACKSON SOLAR MICROGRID
ROOSEVELT PARKWAY
JACKSON, MADISON COUNTY, TENNESSEE
LAYOUT
C-200



SHRUB / GROUND COVER PLANTING
SCREENING ELEVATION VIEW
TREE PLANTING
NOT TO SCALE
LEGEND
GRAPHIC SCALE
COMMUNITY DEVELOPMENT ENTERPRISES
JACKSON SOLAR MICROGRID
ROOSEVELT PARKWAY
JACKSON, MADISON COUNTY, TENNESSEE
LANDSCAPING
C-201

| PROPOSED PIPE TABLE | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| FROM | | TO | | PIPE | | | | | | | |
| STRUCTURE | INV ELEVATION | STRUCTURE | INV ELEVATION | MATERIAL | DIAMETER | LENGTH | SLOPE | DRAIN AREA (AC) | FULL PIPE VELOCITY (FPS) | PIPE FLOW CAPACITY (CFS) | 10 YR DESIGN FLOW (CFS) |
| 1 | [illegible] | 2 | [illegible] | RCP | 24" | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| 2 | [illegible] | 3 | [illegible] | RCP | 24" | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| 4 | [illegible] | 5 | [illegible] | RCP | 24" | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| 5 | [illegible] | 6 | [illegible] | RCP | 24" | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| 7 | [illegible] | 8 | [illegible] | RCP | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |

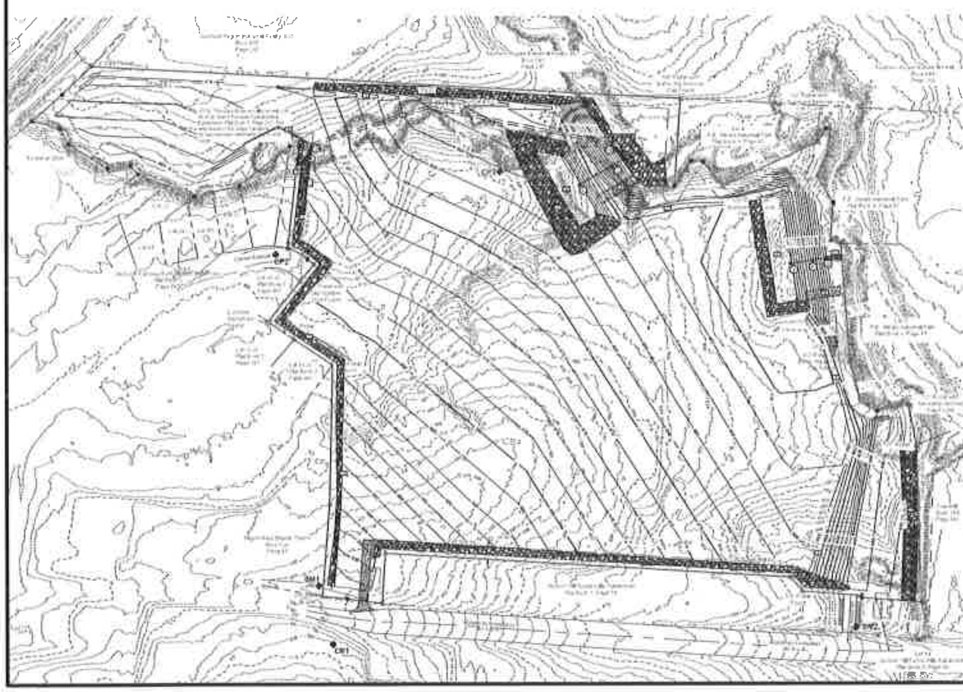
| PROPOSED BOX CULVERT | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FROM | | TO | | SINGLE BARREL CULVERT | | | | | | | | | |
| STRUCTURE | INV. ELEVATION | STRUCTURE | INV. ELEVATION | SPAN HEIGHT | SPAN WIDTH | LENGTH | SLOPE | DRAIN AREA (AC) | [illegible] | FULL PIPE VELOCITY (FPS) | PIPE FLOW CAPACITY (CFS) | 10 YR DESIGN FLOW (CFS) | 100 YR DESIGN FLOW (CFS) |
| 9 | [illegible] | 10 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |

| PROPOSED STRUCTURE TABLE | | | | | | | |
|---|---|---|---|---|---|---|---|
| STRUCTURE | TYPE | RIM | INV. IN | INV. OUT | DEPTH | [illegible] | [illegible] |
| 1 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| 2 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| 3 | [illegible] | [illegible] | | [illegible] | [illegible] | [illegible] | [illegible] |
| 4 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| 5 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| 6 | [illegible] | [illegible] | | [illegible] | [illegible] | [illegible] | [illegible] |
| 7 | [illegible] | [illegible] | | [illegible] | [illegible] | [illegible] | [illegible] |
| 8 | [illegible] | | | [illegible] | | [illegible] | [illegible] |
| 9 | [illegible] | | [illegible] | | | | |
| 10 | [illegible] | | | [illegible] | | | |

GRADING LEGEND

1. 2' TALL CONTAINMENT BERM (REF. C-300)
2. DIVERSION CHANNEL/BERM (REF. C-300)
3. MSE RETAINING WALL
4. DETENTION POND 1
5. DETENTION POND 2
6. RIP RAP CHANNEL LINING
7. CLASS A-1 RIP RAP 2' MIN ON GEOTEXTILE FABRIC
8. 20' WIDE CONCRETE SPILLWAY
9. SLOPE STABILIZATION CLASS A-1 RIP RAP 2' MIN ON GEOTEXTILE FABRIC
10. [illegible]
11. [illegible] REINFORCED CONCRETE BOX CULVERT
12. STORMWATER STRUCTURE

LEGEND




SITE GRADING NOTES

1. EXISTING WET WEATHER CONVEYANCE (WWC) WILL BE REPLACED WITH [illegible] REINFORCED CONCRETE BOX CULVERT
2. EXISTING WWC WILL BE FILLED IN. EXISTING CHANNEL WALLS WILL BE BENCHED BACK AT EACH [illegible] LIFT TO ENSURE PROPER COMPACTION AND COHESION TO EXISTING SOILS
3. ALL FILL MATERIAL SHALL BE PLACED IN [illegible] LIFTS AND COMPACTED TO A [illegible] STANDARD PROCTOR (ASTM D698)
4. [illegible]
5. A DIVERSION CHANNEL/BERM WILL BE CONSTRUCTED ALONG THE WEST SIDE OF THE SITE. THE DIVERSION CHANNEL WILL DIRECT OFFSITE WATER AROUND THE SITE TO A DROP INLET THAT WILL DISCHARGE INTO THE HEADWALL OF THE NEW BOX CULVERT. DIVERSION CHANNEL WILL BE STABILIZED WITH CLASS A-1 RIP RAP AT A MIN. DEPTH OF 2' OVER GEOTEXTILE FABRIC
6. A 2' TALL CONTAINMENT BERM WILL BE CONSTRUCTED ALONG THE LOWER END OF THE SITE. CONTAINMENT BERM WILL DIVERT STORMWATER RUNOFF FROM THE SITE INTO ONE OF TWO DETENTION PONDS
7. FILL SLOPES ALONG THE NORTH PROPERTY LINE WILL BE STABILIZED WITH CLASS A-1 RIP RAP AT A MIN DEPTH OF 2' OVER GEOTEXTILE FABRIC
8. POND SLOPES OF BOTH DETENTION PONDS WILL BE STABILIZED WITH CLASS A-1 RIP RAP AT A MIN DEPTH OF 2' OVER GEOTEXTILE FABRIC
9. EXISTING CHANNEL WILL BE LINED FOR [illegible] BELOW THE OUTLET HEADWALL OF THE NEW BOX CULVERT WITH CLASS A-1 RIP RAP AT A MIN DEPTH OF 2' OVER GEOTEXTILE FABRIC
10. [illegible]

| CONTROL | | | | |
|---|---|---|---|---|
| ID | NORTHING | EASTING | ELEVATION | DESCRIPTION |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| COORDINATE SYSTEM: [illegible] | | | | |
| VERTICAL DATUM: NAVD 1988 | | | | |

GRAPHIC SCALE

( IN FEET )
1 inch = 100 ft.

COMMUNITY DEVELOPMENT ENTERPRISES
JACKSON SOLAR MICROGRID
ROOSEVELT PARKWAY
JACKSON, MADISON COUNTY, TENNESSEE

REVISIONS

LJS L.J. Smith and Associates, Inc.

GRADING

C-300

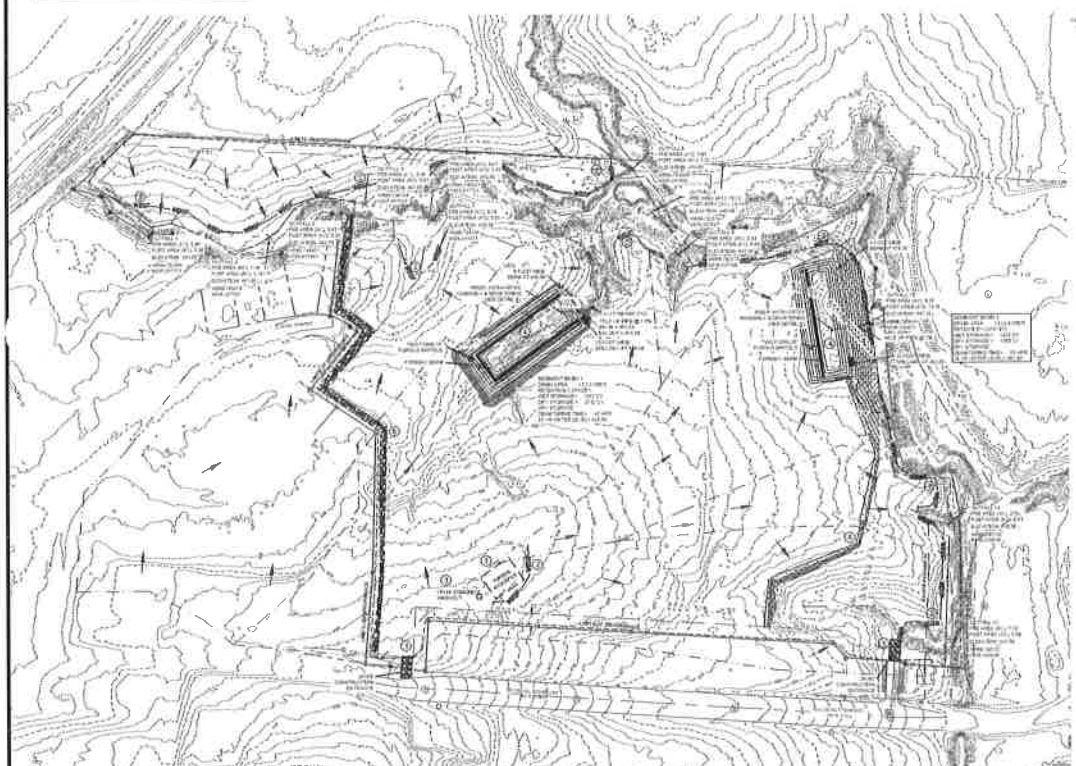
**EROSION CONTROL LEGEND**

| Outfall # | Latitude (N) | Longitude (W) | Approx. Elev. (Feet) | Pre Area (Acres) | Post Area (Acres) | Receiving Waters |
|---|---|---|---|---|---|---|
| OUTFALL 1 | 35.637313 | 88.796385 | 463 | 0.86 | 0.99 | ANDERSON BRANCH |
| OUTFALL 2 | 35.637551 | 88.795472 | 461 | 1.14 | 1.14 | ANDERSON BRANCH |
| OUTFALL 3 | 35.633755 | 88.794744 | 457 | 6.84 | 0.47 | ANDERSON BRANCH |
| OUTFALL 4 | 35.631783 | 88.794225 | 459 | 0.67 | 0.00 | ANDERSON BRANCH |
| OUTFALL 5 | 35.637975 | 88.792655 | 438 | 0.61 | 1.78 | ANDERSON BRANCH |
| OUTFALL 6 | 35.637470 | 88.794772 | 445 | 0.45 | 0.34 | ANDERSON BRANCH |
| OUTFALL 7 | 35.637471 | 88.794226 | 459 | 8.73 | 6.05 | ANDERSON BRANCH |
| OUTFALL 8 | 35.637491 | 88.795555 | 442 | 10.12 | 12.49 | ANDERSON BRANCH |
| OUTFALL 9 | 35.637283 | 88.792313 | 442 | 0.63 | 0.30 | ANDERSON BRANCH |
| OUTFALL 10 | 35.636867 | 88.792871 | 442 | 8.57 | 12.55 | ANDERSON BRANCH |
| OUTFALL 11 | 35.636604 | 88.795195 | 436 | 3.08 | 8.43 | ANDERSON BRANCH |
| OUTFALL 12 | 35.634886 | 88.796137 | 427 | 7.13 | 5.98 | ANDERSON BRANCH |

NOTICE OF COVERAGE HAS BEEN ISSUED FOR A GENERAL CONSTRUCTION PERMIT AND ASSOCIATED GENERAL ARAP PERMIT THROUGH TDEC.

PERMITTED DISTURBANCE: 33 ACRES
TDEC PERMIT NUMBERS
TNR 123488
NR 2102.014

**LEGEND**



GRAPHIC SCALE

( IN FEET )
1 inch = 100 ft.

COMMUNITY DEVELOPMENT ENTERPRISES
JACKSON SOLAR MICROGRID
ROOSEVELT PARKWAY
JACKSON, MADISON COUNTY, TENNESSEE

E.P.S.C PHASE 1

C-400

## EROSION CONTROL LEGEND

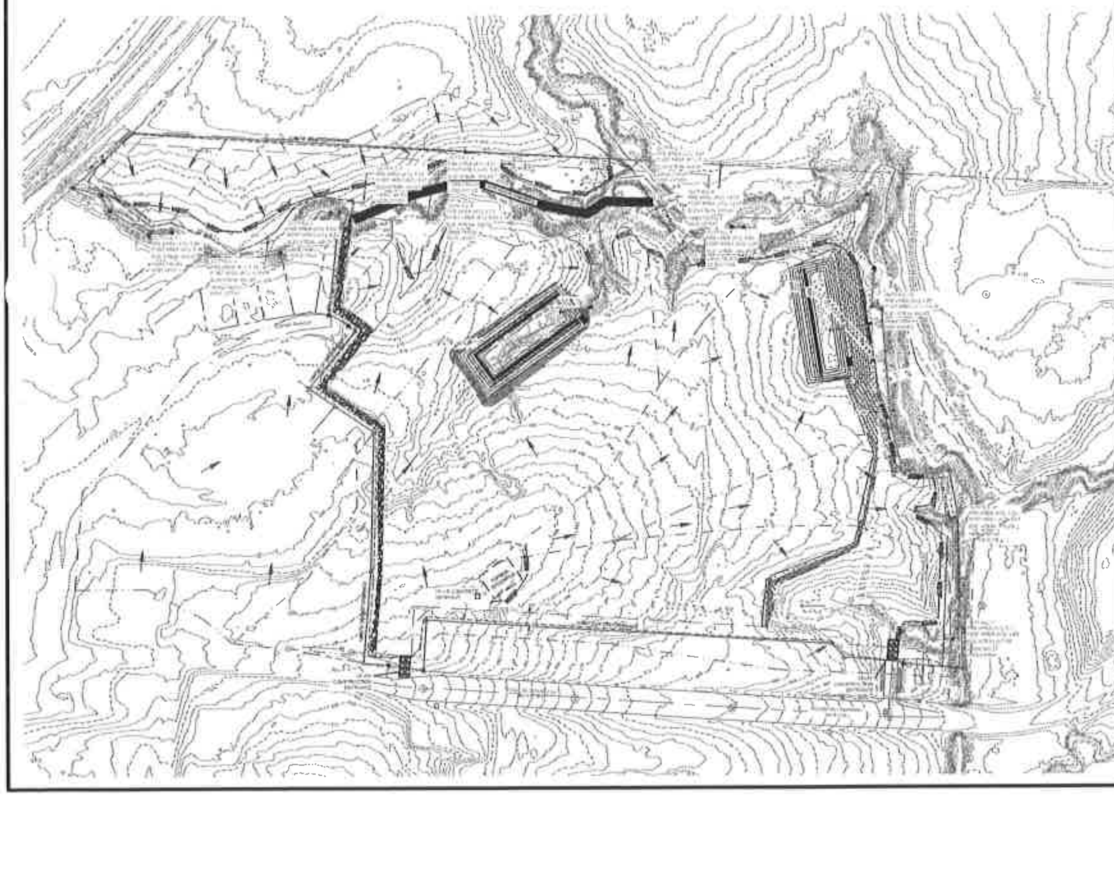
LIMITS OF CONSTRUCTION

| OUTFALL # | LATITUDE (N) | LONGITUDE (W) | APPROX. ELEV (FEET) | PRE AREA (ACRES) | POST AREA (ACRES) | RECEIVING WATERS |
|---|---|---|---|---|---|---|
| OUTFALL 1 | 35.637375 | 88.796068 | 463 | 0.06 | 0.06 | ANDERSON BRANCH |
| OUTFALL 2 | 35.637351 | 88.795473 | 461 | 1.14 | 1.14 | ANDERSON BRANCH |
| OUTFALL 3 | 35.633780 | 88.794744 | 457 | 0.94 | 0.47 | ANDERSON BRANCH |
| OUTFALL 4 | 35.637792 | 88.794229 | 464 | 0.67 | 0.50 | ANDERSON BRANCH |
| OUTFALL 5 | 35.637675 | 88.793950 | 456 | 0.81 | 1.26 | ANDERSON BRANCH |
| OUTFALL 6 | 35.637470 | 88.794722 | 449 | 0.40 | 0.34 | ANDERSON BRANCH |
| OUTFALL 7 | 35.637471 | 88.794208 | 460 | 0.73 | 0.00 | ANDERSON BRANCH |
| OUTFALL 8 | 35.637407 | 88.792950 | 442 | 10.12 | 12.46 | ANDERSON BRANCH |
| OUTFALL 9 | 35.637289 | 88.792312 | 442 | 0.93 | 0.00 | ANDERSON BRANCH |
| OUTFALL 10 | 35.636867 | 88.790071 | 442 | 6.07 | 13.86 | ANDERSON BRANCH |
| OUTFALL 11 | 35.638658 | 88.790150 | 430 | 2.38 | 0.47 | ANDERSON BRANCH |
| OUTFALL 12 | 35.634865 | 88.790117 | 457 | 7.13 | 2.59 | ANDERSON BRANCH |

NOTICE OF COVERAGE HAS BEEN ISSUED FOR A GENERAL CONSTRUCTION PERMIT AND ASSOCIATED GENERAL ARAP PERMIT THROUGH TDEC.

PERMITTED DISTURBANCE: 32 ACRES
TDEC PERMIT NUMBERS:
TNR 123480
NR 2102.014

## LEGEND



GRAPHIC SCALE

( IN FEET )
1 inch = 100 ft.

COMMUNITY DEVELOPMENT ENTERPRISES
JACKSON SOLAR MICROGRID
ROOSEVELT PARKWAY
JACKSON, MADISON COUNTY, TENNESSEE

E.P.S.C PHASE 2

C-401

LJS L.J. Smith and Associates, Inc.

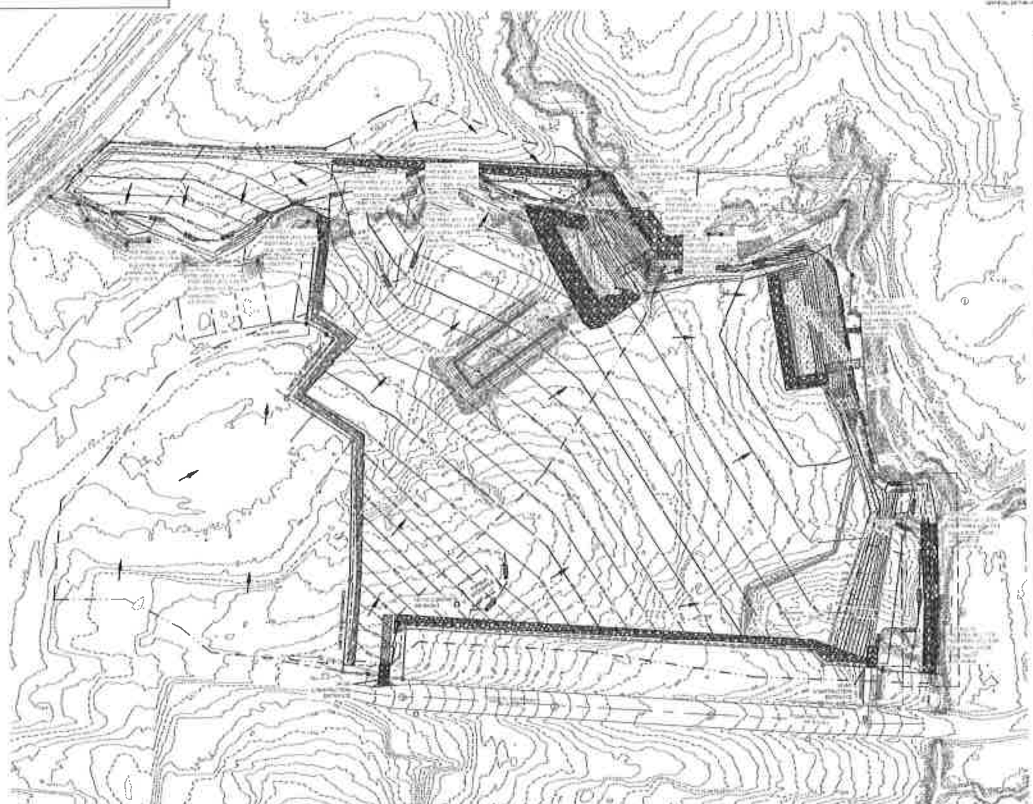
## EROSION CONTROL LEGEND

| OUTFALL # | LATITUDE (N) | LONGITUDE (W) | APPROX ELEV. (FEET) | PRE AREA (ACRES) | POST AREA (ACRES) | RECEIVING WATERS |
|---|---|---|---|---|---|---|
| OUTFALL 1 | 35.637323 | 88.796385 | 463 | 0.98 | 0.58 | ANDERSON BRANCH |
| OUTFALL 2 | 35.637323 | 88.795473 | 461 | 1.14 | 1.19 | ANDERSON BRANCH |
| OUTFALL 3 | 35.603755 | 88.754744 | 457 | 0.64 | 0.47 | ANDERSON BRANCH |
| OUTFALL 4 | 35.637763 | 88.794225 | 456 | 0.67 | 0.00 | ANDERSON BRANCH |
| OUTFALL 5 | 35.637475 | 88.793950 | 456 | 0.61 | 1.20 | ANDERSON BRANCH |
| OUTFALL 6 | 35.637475 | 88.794757 | 445 | 0.40 | 0.34 | ANDERSON BRANCH |
| OUTFALL 7 | 35.637471 | 88.794208 | [illegible] | 0.73 | 0.00 | ANDERSON BRANCH |
| OUTFALL 8 | 35.637461 | 88.793669 | 440 | 10.12 | 12.40 | ANDERSON BRANCH |
| OUTFALL 9 | 35.637285 | 88.793312 | 442 | 0.83 | 0.00 | ANDERSON BRANCH |
| OUTFALL 10 | 35.636067 | 88.790871 | 442 | 9.57 | 13.98 | ANDERSON BRANCH |
| OUTFALL 11 | 35.635609 | 88.790150 | 439 | 2.06 | 0.43 | ANDERSON BRANCH |
| OUTFALL 12 | 35.634869 | 88.790127 | 437 | 7.13 | 3.09 | ANDERSON BRANCH |

NOTICE OF COVERAGE HAS BEEN ISSUED FOR A GENERAL CONSTRUCTION PERMIT AND ASSOCIATED GENERAL ARAP PERMIT THROUGH TDEC.

PERMITTED DISTURBANCE: 32 ACRES
TDEC PERMIT NUMBERS
TNR 133400
NR 2102.014

## LEGEND



GRAPHIC SCALE

1 inch = 100 ft.

E.P.S.C PHASE 3

C-402

COMMUNITY DEVELOPMENT ENTERPRISES
JACKSON SOLAR MICROGRID
ROOSEVELT PARKWAY
JACKSON, MADISON COUNTY, TENNESSEE

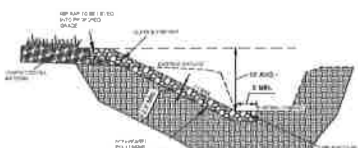
EROSION CONTROL LEGEND

| OUTFALL # | LATITUDE (N) | LONGITUDE (W) | APPROX. ELEV (FEET) | PRE AREA (ACRES) | POST AREA (ACRES) | RECEIVING WATERS |
|---|---|---|---|---|---|---|
| OUTFALL 1 | 35.927373 | 88.790589 | 463 | 0.08 | 0.08 | ANDERSON BRANCH |
| OUTFALL 2 | 35.927321 | 88.795473 | 461 | 1.14 | 1.14 | ANDERSON BRANCH |
| OUTFALL 3 | 35.923756 | 88.794144 | 457 | 0.54 | 0.47 | ANDERSON BRANCH |
| OUTFALL 4 | 35.927762 | 88.794076 | 458 | 0.67 | 0.32 | ANDERSON BRANCH |
| OUTFALL 5 | 35.927970 | 88.792950 | 458 | 0.81 | 1.26 | ANDERSON BRANCH |
| OUTFALL 6 | 35.927470 | 88.794723 | 440 | 5.45 | 0.54 | ANDERSON BRANCH |
| OUTFALL 7 | 35.927471 | 88.794308 | 452 | 8.79 | 0.34 | ANDERSON BRANCH |
| OUTFALL 8 | 35.927401 | 88.792986 | 440 | 13.13 | 12.49 | ANDERSON BRANCH |
| OUTFALL 9 | 35.927390 | 88.793312 | 442 | 0.03 | 0.36 | ANDERSON BRANCH |
| OUTFALL 10 | 35.926847 | 88.790071 | 442 | 8.57 | 13.85 | ANDERSON BRANCH |
| OUTFALL 11 | 35.926838 | 88.790183 | 430 | 2.05 | 0.43 | ANDERSON BRANCH |
| OUTFALL 12 | 35.924669 | 88.790137 | 427 | 7.13 | 2.58 | ANDERSON BRANCH |

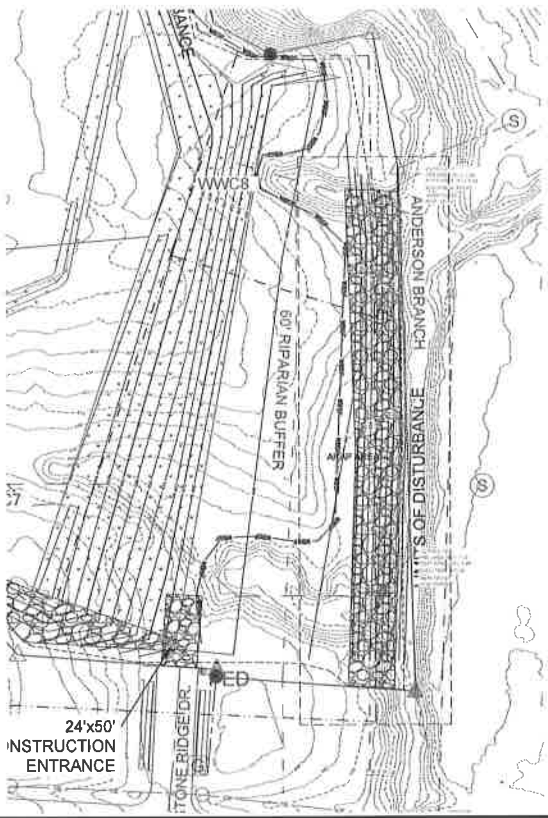
NOTICE OF COVERAGE HAS BEEN ISSUED FOR A GENERAL CONSTRUCTION PERMIT AND ASSOCIATED GENERAL ARAP PERMIT THROUGH TDEC.

PERMITTED DISTURBANCE: 32 ACRES
TDEC PERMIT NUMBERS:
TNR 123488
NR 2102.014

LEGEND



4.12 RIP RAP REVETMENT-BANK STABILZATION




GRAPHIC SCALE

COMMUNITY DEVELOPMENT ENTERPRISES
JACKSON SOLAR MICROGRID
ROOSEVELT PARKWAY
JACKSON, MADISON COUNTY, TENNESSEE

A.R.A.P.

C-403

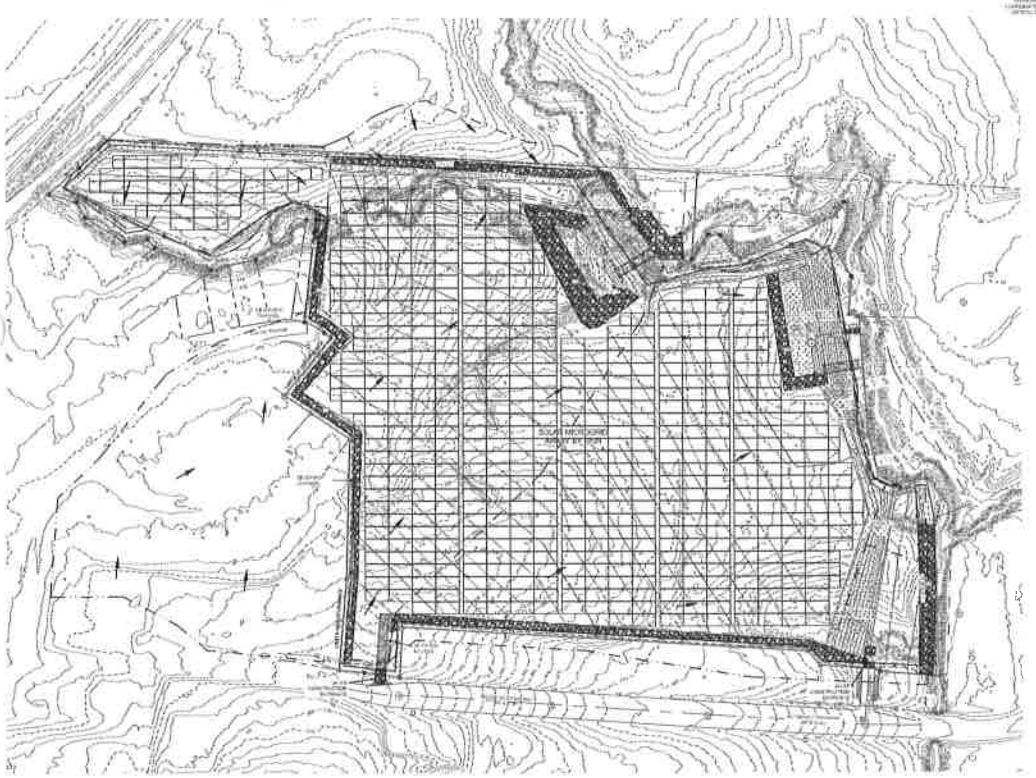
## EROSION CONTROL LEGEND

| OUTFALL # | LATITUDE (N) | LONGITUDE (W) | APPROX. ELEV. (FEET) | PRE AREA (ACRES) | POST AREA (ACRES) | RECEIVING WATERS |
|---|---|---|---|---|---|---|
| OUTFALL 1 | 35.637373 | 88.796366 | 463 | 0.98 | 0.98 | ANDERSON BRANCH |
| OUTFALL 2 | 35.637331 | 88.795473 | 461 | 1.14 | 1.14 | ANDERSON BRANCH |
| OUTFALL 3 | 35.633750 | 88.794794 | 467 | 0.64 | 0.47 | ANDERSON BRANCH |
| OUTFALL 4 | 35.637763 | 88.794225 | 455 | 0.67 | 0.03 | ANDERSON BRANCH |
| OUTFALL 5 | 35.637973 | 88.793800 | 456 | 0.91 | 1.28 | ANDERSON BRANCH |
| OUTFALL 6 | 35.637470 | 88.794722 | 445 | 0.40 | 8.34 | ANDERSON BRANCH |
| OUTFALL 7 | 35.637471 | 88.794208 | 458 | 0.77 | 0.00 | ANDERSON BRANCH |
| OUTFALL 8 | 35.637491 | 88.792968 | 446 | 10.12 | 12.36 | ANDERSON BRANCH |
| OUTFALL 9 | 35.637285 | 88.792312 | 442 | 0.52 | 0.00 | ANDERSON BRANCH |
| OUTFALL 10 | 35.635667 | 88.790871 | 443 | 4.07 | 13.58 | ANDERSON BRANCH |
| OUTFALL 11 | 35.635638 | 88.790180 | 490 | 2.06 | 0.43 | ANDERSON BRANCH |
| OUTFALL 12 | 35.634868 | 88.790127 | 427 | 7.13 | 2.58 | ANDERSON BRANCH |

NOTICE OF COVERAGE HAS BEEN ISSUED FOR A GENERAL CONSTRUCTION PERMIT AND ASSOCIATED GENERAL ARAP PERMIT THROUGH TDEC.

PERMITTED DISTURBANCE: 53 ACRES
TDEC PERMIT NUMBERS
TNR 133490
NR 2102.014

## LEGEND



GRAPHIC SCALE

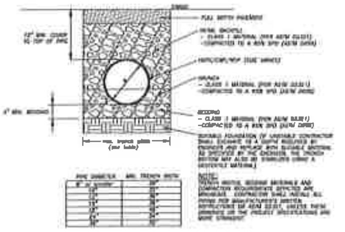
( IN FEET )
1 inch = 100 ft.

COMMUNITY DEVELOPMENT ENTERPRISES
JACKSON SOLAR MICROGRID
ROOSEVELT PARKWAY
JACKSON, MADISON COUNTY, TENNESSEE

REVISIONS

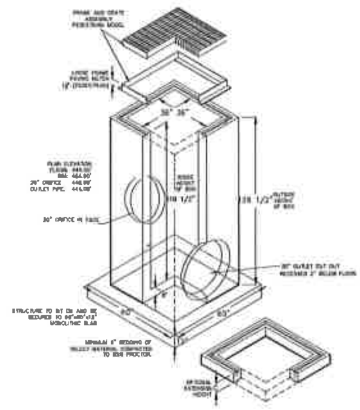
E.P.S.C PHASE 4

C-404



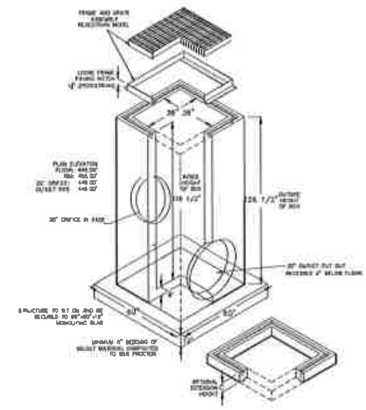
3.01 DRAINAGE PIPE TRENCH DETAIL

NO SCALE



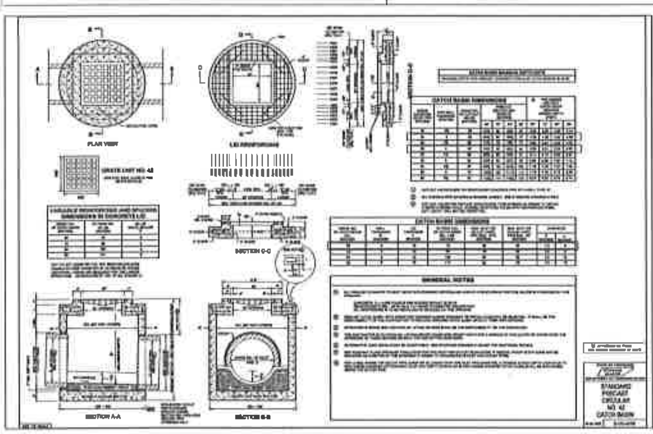
3.02 DETENTION POND 1 OUTLET STRUCTURE

NO SCALE



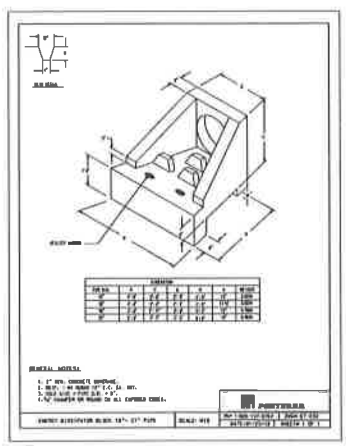
3.03 DETENTION POND 2 OUTLET STRUCTURE

NO SCALE



3.04 TYPE 42 DROP INLET

NO SCALE



3.05 HEADWALL WITH ENERGY DISSIPATOR

NO SCALE

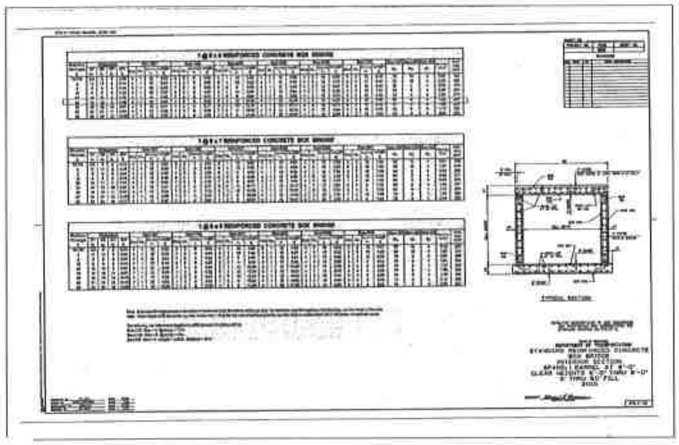
COMMUNITY DEVELOPMENT ENTERPRISES
JACKSON SOLAR MICROGRID
ROOSEVELT PARKWAY
JACKSON, MADISON COUNTY, TENNESSEE

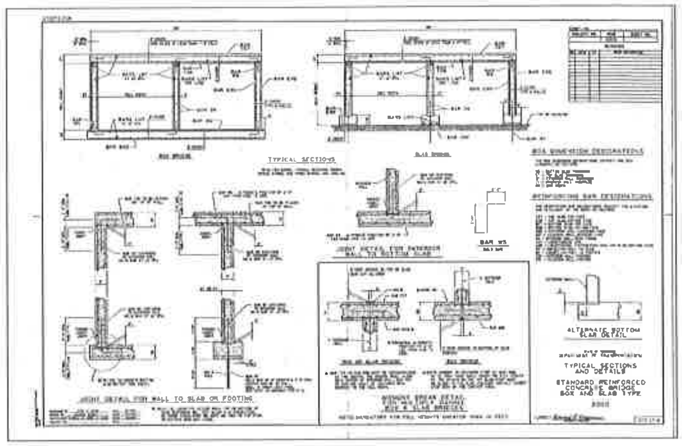
REVISIONS

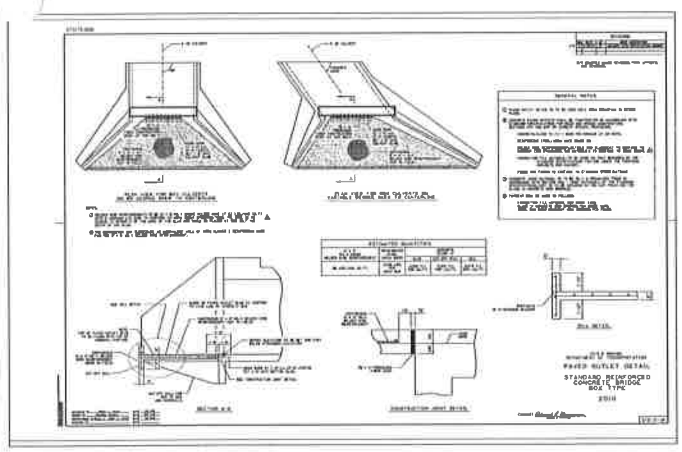
SITE DETAILS

C-900

LTS L.L. Smith and Associates, Inc.







EMERGENCY SPILLWAY

NO SCALE

COMMUNITY DEVELOPMENT ENTERPRISES

JACKSON SOLAR MICROGRID

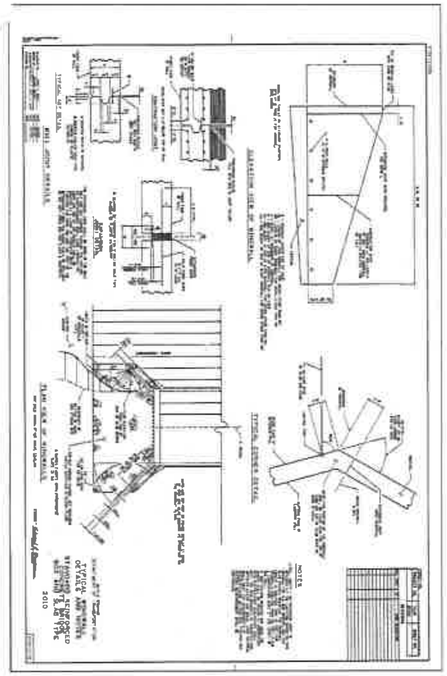
ROOSEVELT PARKWAY

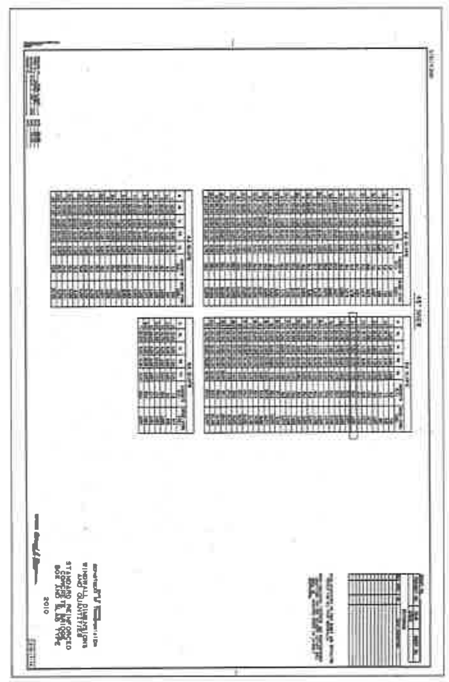
JACKSON, MADISON COUNTY, TENNESSEE

SITE DETAILS

C-901

L.I. Smith and Associates, Inc.





SHEET

SITE DETAILS

NUMBER

C-902

L.I. Smith and Associates, Inc.

LAND DEVELOPMENT | INFRASTRUCTURE DESIGN

— SURVEYING SERVICES —

DRAWN BY: MTG | CHECKED BY: WPE | SCALE

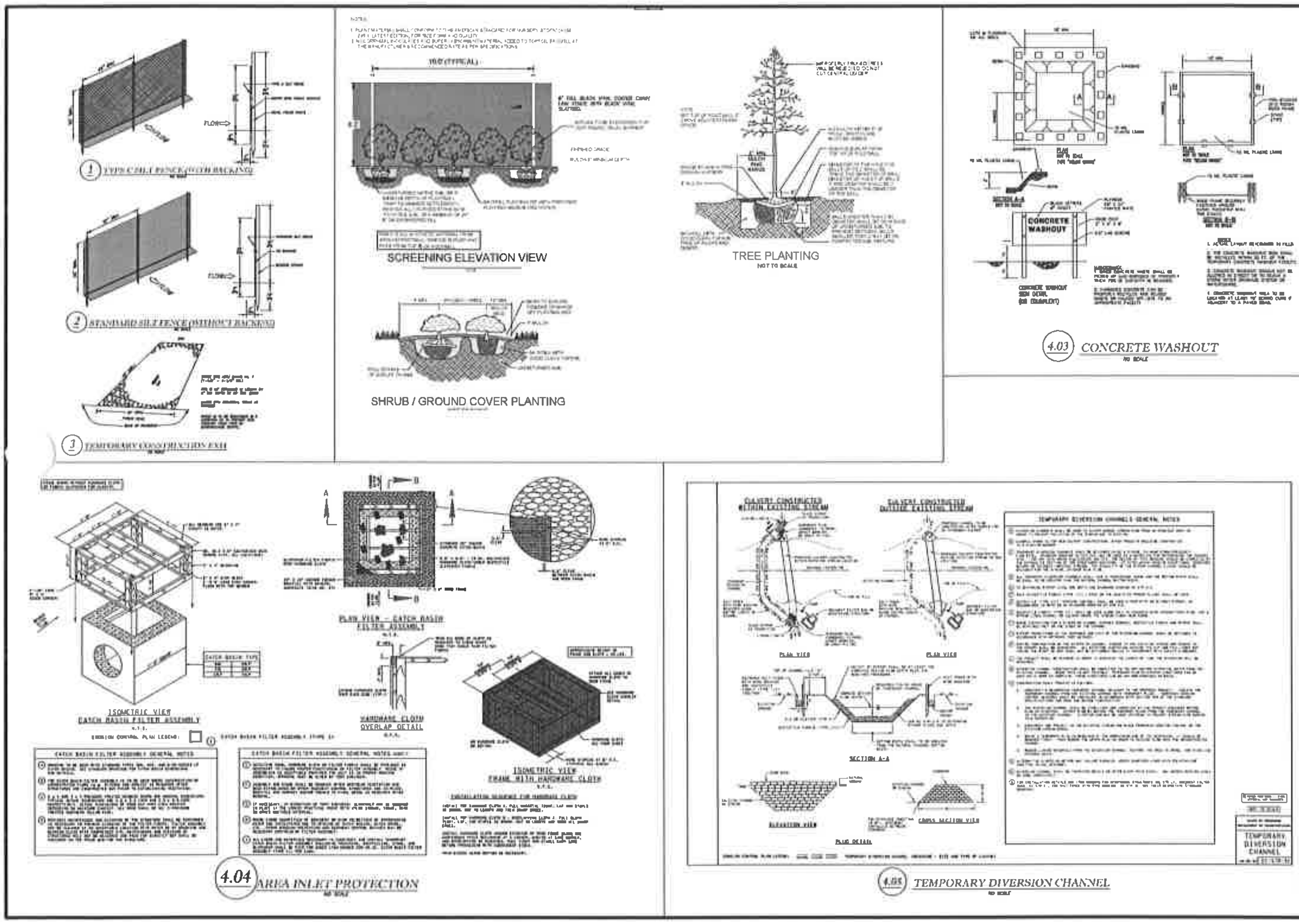
REVISIONS

COMMUNITY DEVELOPMENT ENTERPRISES

JACKSON SOLAR MICROGRID

ROOSEVELT PARKWAY

JACKSON, MADISON COUNTY, TENNESSEE




COMMUNITY DEVELOPMENT ENTERPRISES

JACKSON SOLAR MICROGRID

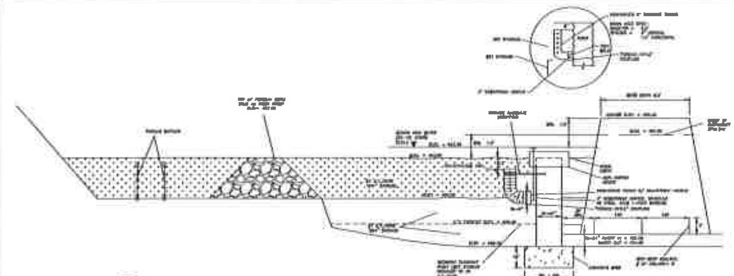
ROOSEVELT PARKWAY

JACKSON, MADISON COUNTY, TENNESSEE

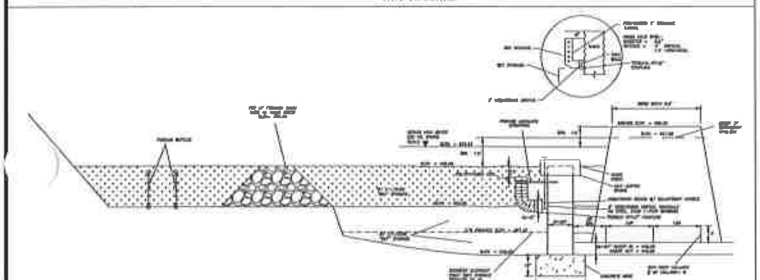
REVISIONS

SITE DETAILS

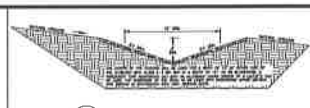
C-903



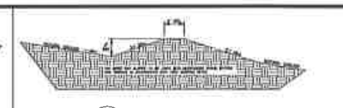
4.06 SEDIMENT BASIN 1 (OUTFALL 8) CROSS SECTION & DEWATERING APPARATUS WITH DRAWDOWN DEVICE
NOT TO SCALE



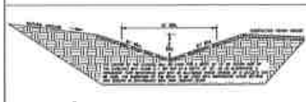
4.07 SEDIMENT BASIN 2 (OUTFALL 10) CROSS SECTION & DEWATERING APPARATUS WITH DRAWDOWN DEVICE
NOT TO SCALE



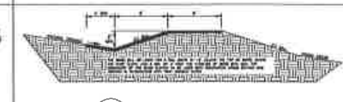
4.08 TEMPORARY DIVERSION DITCH



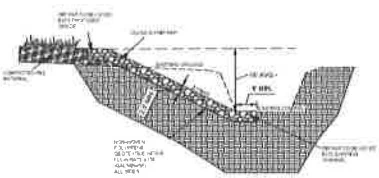
4.10 DIVERSION BERM



4.09 PERMANENT DIVERSION DITCH



4.11 CONTAINMENT BERM



4.12 RIP RAP REVETMENT-BANK STABILZATION

COMMUNITY DEVELOPMENT ENTERPRISES
JACKSON SOLAR MICROGRID
ROOSEVELT PARKWAY
JACKSON, MADISON COUNTY, TENNESSEE

REVISIONS

SITE DETAILS

C-904

# EXHIBIT 13

SynEnergy

# ***<u>Economic Impact of the</u>***

# ***<u>Jackson Solar Facility</u>***

*Economic Impact is the sum of the value of all goods & services produced in a region*

- Gross Regional Product (GRP) – the local equivalent to GDP
- Only includes goods & services produced in Madison County and Jackson, and does not include the value of goods and services imported from outside the County
    - For example, you buy a TV at the local Walmart
        - The service provided by the stockers, cashiers & managers are all counted as *<u>local</u>* production and their contribution to Economic Impact is measured by their compensation
        - And the wages that those employees spend *<u>locally</u>* are also counted towards Economic Impact
        - The TV itself, and the transportation to get it here, are imported goods & services and are not counted in GRP

- The construction of the Jackson Solar Facility will add ***$100 million*** to the county economy in 2021, and at peak employment will create an additional ***678 jobs***
    - $67 million will be invested in the construction of the system.
    - An additional $33 million in economic benefit will occur from secondary effects such as local purchase of tools and materials, equipment rentals, food and lodging – and additional employee wages for firms providing those goods and services.
- After the construction is complete, the power generation and shared supplemental energy will provide for ***8 permanent jobs*** and ***$6.8 million*** of value annually
- Reinvestment of customer energy savings into production capacity would result in creation of an additional **$5.4 million** economic impact and **14 permanent jobs**
- Assuming an annual growth rate of 4% in economic impact, the construction and operation of the Jackson Solar Facility would result in <u>**a total economic impact of $229M, as well as 678 temporary and 28 permanent jobs**</u>

## Tax revenues & expenditures

| | Construction (2021) | 10 yr Total |
|---|---|---|
| City Tax Revenue | $ 316,000 | $ 513,000 |
| County Tax Revenue | $ 775,000 | $ 1,251,000 |
| State Tax Revenue | $ 1,955,000 | $ 3,190,000 |
| Federal Tax Revenue | $ 7,732,000 | $11,473,000 |
| **Total taxes (Fed+S&L)** | **$10,778,000** | **$16,426,000** |

### Study Background Sheet

IMPLAN® is nationally recognized as the leading standard for economic impact analysis software

- Developed by the University of Minnesota in 1978 and refined through the years
- Customers include a wide range of federal agencies & departments and academia
  - Departments of Defense, Agriculture, Commerce, Coast Guard, Forestry
  - University of Minnesota, Purdue, Arizona State, Clemson
- Data sets sourced from
  - Bureau of Labor Statistics
  - Bureau of Economic Analysis
  - Census Bureau
  - Department of Agriculture
- Impacts on 528 different business sectors are measured

Data set for this study is specific to Madison County (2018 – latest available federal data)

- Accounts for commuting patterns
- Uses Madison County-specific industries and labor base
- Madison County resident spending patterns

The following types of outputs are included

- Direct Effect – construction and operations
- Indirect Effect – Local business-business by goods or services vendors supporting the construction and operations (wholesalers, retailers, architects, realtors, accountants, etc). Only Madison County produced goods & services count towards the economic impact
- Induced Effect – Result of increased local wages, whether from Direct or Indirect Effects

Modeling assumptions

- Tax rates are based on FY20 rates
- Employment is measured in terms of full-time equivalents (FTEs)