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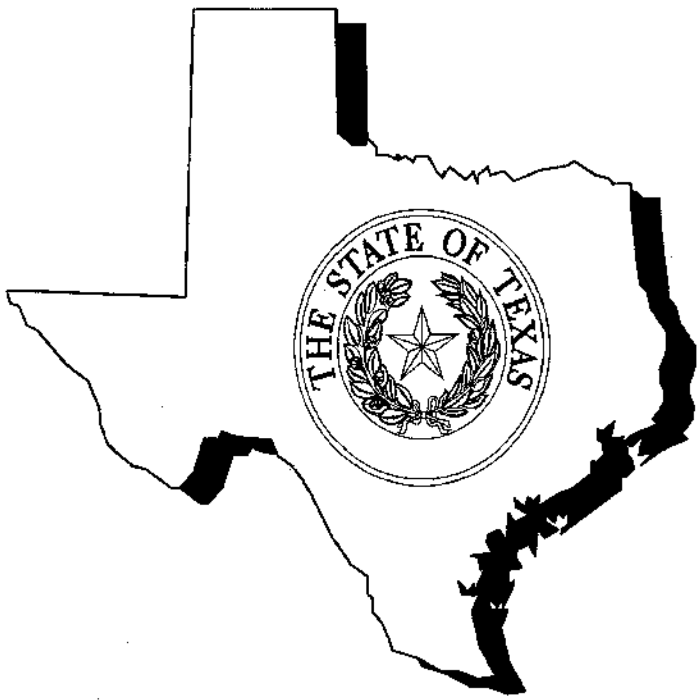
APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	§ § § § §	**BEFORE THE STATE OFFICE** **OF** **ADMINISTRATIVE HEARINGS**



DIRECT TESTIMONY OF

MICHAEL (MIKE) NOTH, P.E.

INFRASTRUCTURE DIVISION

PUBLIC UTILITY COMMISSION OF TEXAS

March 7, 2025

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ATTACHMENTS

I. STATEMENT OF QUALIFICATIONS

Q. Please state your name, occupation, and business address.

A. My name is Mike Noth. I am employed by the Public Utility Commission of Texas (PUC or Commission), as an Engineer VI within the Infrastructure Division. My business address is 1701 North Congress Avenue, Austin, Texas 78711-3326.

Q. Please briefly outline your educational and professional background.

A. I have a Bachelor of Science degree in Electrical Engineering. I have been employed at the PUC since November of 2024. Attachment MN-1 details my educational and professional background.

Q. Are you a registered professional engineer?

A. Yes. I am a registered Professional Engineer in Texas, license number 94052.

Q. Have you previously testified as an expert before the Commission?

A. Yes. I submitted testimony for Docket No. 57263.

II. PURPOSE AND SCOPE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present Commission Staff's recommendations concerning the application of Southwestern Public Service Company (SPS) for approval of its System Resiliency Plan (SRP) and the subsequent Resiliency Measures.

Q. What statute allows a utility to file a plan to enhance the resiliency of its transmission and distribution system?

A. Section 38.078 of the Public Utility Regulatory Act (PURA)[1] allows a utility to file a resiliency plan in a manner authorized by Commission rule.

Q. Do Commission rules establish requirements for transmission and distribution resiliency plans?

A. Yes. 16 Tex. Admin. Code (TAC) § 25.62 explains the purpose of the system resiliency plan, defines applicable terms, provides requirements for filing a system resiliency plan and for the Commission processing of a resiliency plan, identifies cost recovery methods, and establishes resiliency plan reporting requirements.

Q. What measures must be used by the utility to enhance the resiliency of its transmission and distribution system?

A. A resiliency plan is comprised of one or more measures designed to prevent, withstand, mitigate, or more promptly recover from the risks posed to the electric utility's transmission and distribution systems by resiliency events. Both the statute and Commission rule state that each measure must utilize one or more of the following methods:[2]

(A) hardening electric transmission and distribution facilities;
(B) modernizing electric transmission and distribution facilities;
(C) undergrounding certain electric distribution lines;
(D) lightning mitigation measures;
(E) flood mitigation measures;
(F) information technology;
(G) cybersecurity measures;

[1] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-66.016.

[2] PURA § 38.078(b) and 16 TAC § 25.62(c)(1).

(H) physical security measures;
(I) vegetation management; or
(J) wildfire mitigation and response.

Q. What issues identified by the Commission must be addressed in this docket?

A. In the Preliminary Order filed on January 2, 2025, the Commission identified the following issues that must be addressed:

Notice

1. Did the electric utility provide notice of its filed resiliency plan?

Application

2. Is the application sufficient?
3. Does the application include all required information?
4. Did the electric utility file proof that notice has been provided?
5. If the resiliency plan is sufficient, when was the resiliency plan deemed sufficient, and what is the deadline for the Commission to issue an order approving, modifying, or denying the resiliency plan?
6. Does the resiliency plan include an executive summary or comprehensive chart that explains the plan objectives, the resiliency events or related risks the plan is designed to address, the plan's proposed resiliency measures, the proposed metrics or criteria for evaluating the plan's effectiveness, the plan's cost and benefits, and how the overall plan is in the public interest?

Contents of the Resiliency Plan

7. What measures comprise the electric utility's resiliency plan to prevent, withstand, mitigate, or promptly recover from the risks posed by resiliency events to its transmission and distribution systems? In evaluating the measures, please address the following:
    a. Does each measure use one or more of the methods listed in PURA and the Commission rule?
    b. What risk or risks posed by resiliency events is each measure intended to prevent, withstand, mitigate, or more promptly recover from?
    c. How did the electric utility prioritize the identified resiliency event and, if applicable, the particular geographic area, system, or facilities where each measure will be implemented?
    d. How effective is each measure in preventing, withstanding, mitigating, or promptly recovering from the risks posed by the identified resiliency event? In addressing this question, identify any evidence that is quantitative, performance-based, or provided by an independent entity with relevant expertise which supports the effectiveness of each measure.
    e. What are the expected benefits of each resiliency measure, including, as applicable, reduced system restoration costs, reduction in the frequency or duration of outages for customers, and any improvement in the overall service reliability for customers, including the classes of customers served and any critical load designations?

f. Is any measure a coordinated effort with federal, state, or local government programs, or would the measure benefit from any federal, state, or local funding opportunities?

g. How does each measure compare, such as by cost or performance, to reasonable and readily identifiable alternatives?

h. Does any measure require a transmission system outage to implement?

i. Does any measure entail revising the functionality of AMS smart meters? If so, has any required deployment plan filing or notice been accomplished?

8. What types of resiliency events and associated resiliency-related risks is the resiliency plan designed to prevent, withstand, mitigate, or promptly recover from? For each resiliency event identified and described by the resiliency plan, please address the following:

a. Is the type of resiliency event defined with sufficient detail to allow the electric utility or Commission to determine whether an actual set of circumstances qualifies as a resiliency event of that type?

b. Does the resiliency event type include one or more magnitude thresholds, if appropriate, based on the risks posed to the electric utility's systems by that type of event?

c. What are the system characteristics that make the electric utility's transmission and distribution systems susceptible to the identified resiliency event type?

d. What is the electric utility's experience with, if applicable, and forecasted risk of the identified event type, including whether the forecasted risk is specific to a particular system or geographic area?

e. Do any studies conducted by the independent system operator or an independent entity with relevant expertise support the forecasted risk of the identified event type?

9. For each measure in the resiliency plan, what is the appropriate metric or criteria for evaluating the effectiveness of that measure in preventing, withstanding, mitigating, or promptly recovering from the risks associated with the resiliency event it is designed to address?

10. Does the resiliency plan include measures that are similar to other existing programs or measures, such as a storm hardening plan under 16 TAC § 25.95 or a vegetation management plan under 16 TAC § 25.96, or programs or measures otherwise required by law? If so, how are the measures in the resiliency plan distinct from these programs and measures and, if appropriate, how do the related items work in conjunction with one another?

11. How does the metric or criteria for evaluating the effectiveness of each measure in the resiliency plan differentiate between system improvement due to the measure in the resiliency plan and system improvement due to other existing programs or measures?

12. What systematic approach will be used to implement the resiliency plan during at least a three-year period? In addressing this question, please address details of the implementation, including estimated capital costs, estimated operations and maintenance expenses, an estimated timeline for completion, and, when practicable and appropriate, estimated net salvage value (value of the retired asset less depreciation and cost of removal) and remaining service lives of any assets expected to be retired or replaced by resiliency-related investments. Please also address relevant

cost drivers (e.g., line miles, frequency of inspections, frequency of trim cycles, etc.) that would affect the estimates.

13. What assumptions does the electric utility's resiliency plan make, including assumptions underlying evidence of the risks posed by the resiliency events, evidence of the effectiveness and expected benefits of each resiliency of each resiliency measure, and comparisons with the cost or performance of readily identifiable alternatives? Are those assumptions reasonable? In answering this question, please address the following.

a. What is the extent to which different reasonable assumptions would affect evidence of the risks posed by the resiliency events, evidence of the effectiveness and expected benefits of each resiliency measure, or comparisons of the cost or performance of a resiliency measure to that of readily identifiable alternatives?

Hurricane Mitigation

14. What specific measures are included in the electric utility's resiliency plan that address lessons learned from recent hurricanes? Please address whether these specific measures include more resilient distribution lines and poles, increased vegetation management, and hardening of transmission lines and facilities to help mitigate hurricane impacts.

15. Does the electric utility's resiliency plan include specific measures to increase the wind rating of distribution lines and poles?

16. Does the electric utility's resiliency plan include specific measures for vegetation management that will help mitigate hurricane impacts?

17. Does the electric utility' s resiliency plan include specific measures to increase the wind rating of transmission lines and facilities?

Wildfire Mitigation

18. What are the resiliency measures related to wildfire mitigation in the electric utility's resiliency plan?
19. Do the electric utility's proposed system hardening resiliency measures mitigate wildfire risk?
20. Has the electric utility included in its resiliency plan an asset inspection resiliency measure related to wildfire mitigation?
21. Has the electric utility included in its resiliency plan a vegetation management resiliency measure related to wildfire mitigation?
22. Has the electric utility included in its resiliency plan an undergrounding resiliency measure related to wildfire mitigation?
23. Has the electric utility included in its resiliency plan wildfire monitoring and advanced analytics resiliency measures related to wildfire mitigation?

Commission Review of the Resiliency Plan

24. Should the Commission approve, deny, or modify the resiliency plan? In answering this question, address whether approving the plan is in the public interest by considering the following factors:
    a. the extent to which the plan is expected to enhance system resiliency, including:
        i. the verifiability and severity of the resiliency risks posed by the resiliency events the resiliency plan is designed to address;

ii. the extent to which the plan will enhance resiliency of the electric utility's system, mitigate system restoration costs, reduce the frequency or duration of outages, or improve overall service reliability for customers during and following a resiliency event;

iii. the extent to which the resiliency plan prioritizes areas of lower performance; and

iv. the extent to which the resiliency plan prioritizes critical load as defined in 16 TAC § 25.52.

b. the estimated time and costs of implementing the measures proposed in the resiliency plan;

c. whether there are more efficient, cost-effective, or otherwise superior means of preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the resiliency events addressed by the resiliency plan; or

d. other relevant factors.

25. Does Commission Staff request that the electric utility provide any additional information and updates on the status of the resiliency plan submitted?

<u>Cost Recovery</u>

26. Does the utility request approval of a resiliency cost recovery rider? If so, does the utility's proposed cost recovery comply with Commission rule?

Q. Which issues in this proceeding have you addressed in your testimony?

A. I have addressed issues from the Preliminary Order and the requirements of 16 TAC § 25.62.

Q. If you do not address an issue or position in your testimony, should that be interpreted as Staff supporting any other party's position on that issue?

A. No. The fact that I do not address an issue in my testimony should not be considered as agreeing, endorsing, or consenting to any position taken by any other party in this proceeding.

Q. What is the scope of your testimony?

A. The scope of my testimony is to provide Commission Staff's recommendation specifically focusing on Measure 2 - Distribution System Protection Modernization, which includes two programs: Mainline Automated Reclosing Deployment, and Lateral Reclosing Deployment. Please refer to the testimonies of Staff witnesses Eduardo Acosta, David Bautista, Ruth Stark, and Chuck Bondurant for discussion on the remaining measures.

Q. What have you relied upon or considered to reach your conclusions and make your recommendations?

A. I have relied upon my review and analysis of the data contained in SPS's application and the application's accompanying attachments. I have also relied upon my review of the direct testimonies filed in this proceeding by or on behalf of SPS and responses to requests for information.

III. RECOMMENDATIONS

Q. What recommendations do you have regarding the application of SPS for approval of its Transmission and Distribution System Resiliency Plan?

A. I recommend the Commission approve Measure 2 - Distribution System Protection

Modernization which includes the Mainline Automated Reclosing Deployment and the Lateral Reclosing Deployment programs. The basis for my recommendation is discussed in more detail throughout the remainder of my testimony.

IV. SYSTEM RESILIENCY PLAN OVERVIEW

Q. Please describe SPS's proposed resiliency plan.

A. On December 30, 2024, SPS submitted its proposed resiliency plan for approval.[3] The plan has a total of five resiliency measures identified by SPS that will improve the system's ability to prevent, withstand, mitigate, and/or more promptly recover from the resiliency events experienced in their service territory.[4] The measures are Measure 1- Distribution Overhead Hardening, Measure 2- Distribution System Protection Modernization, Measure 3- Communication Modernization, Measure 4- Operational Flexibility, and Measure 5- Wildfire Mitigation.[5] The estimated total cost for implementing the proposed resiliency plan over a three-year period (2025-2028) is $538.3 million.[6]

Q. Please provide a brief description for each of the resiliency measures you are addressing in your testimony.

A. I address one proposed measure, Distribution System Protection Modernization. This measure includes two programs which are shown in the table below with a brief description.

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[3] *See* SPS's Application for Approval of its Transmission and Distribution System Resiliency Plan (Dec 30, 2024)

[4] Application at 3

[5] *Id.*

[6] *Id.* at 3.

DISTRIBUTION SYSTEM PROTECTION MODERNIZATION	DESCRIPTION
Mainline Automated Reclosing Program	This project consists of installing system protection of the distribution mainline incorporating remotely controlled circuit segmentation via reclosers for additional resiliency and faster recovery times.
Lateral Reclosing Deployment Program	This project consists of redesigning and rebuilding remotely controlled lateral distribution circuit segments via reclosers to revised engineering standards.

Q. Could you briefly summarize the purpose of SPS's resiliency plan?

A. Yes. SPS provides electric service in the High Plains and Low Rolling Plains climate divisions in the Texas Panhandle region.[7] The weather in SPS's service area in Texas can be violent and variable.[8] SPS's service area can experience weather events ranging from icing and blizzards to extreme heat and drought, flooding, high winds, and tornadoes.[9] High winds and winter weather have the greatest impact on the SPS System and customers.[10] High winds account for nearly 70% of all outages from 2010 through 2023, and over 45% of Customer Minutes Interrupted ("CMI") over that same period.[11] Winter weather accounts for 8.5% of outages during that period, but its per-outage impact is much higher, accounting for over 50% of CMI during that time frame.[12] The proposed SRP plan is designed to prevent, withstand, mitigate, and allows SPS's distribution system to more

[7] *Id.* Attachment A at 27.

[8] Application at 8.

[9] *Id.*

[10] *Id.*

[11] *Id.*

[12] *Id.* at 8.

promptly recover from the most predominant resiliency events.

Q. Has an independent organization performed an analysis and review of SPS's resiliency plan?

A. Yes. 1898 & Co. of Burns and McDonell was hired to conduct and evaluate SPS's SRP. 1898 & Co. was selected based on its significant operational experience and considerable knowledge of vegetation control, asset management, and wildfire mitigation, which is the forefront of SPS's SRP. In order to determine the most beneficial and cost-effective measure to address SPS's vulnerabilities, SPS relied on the evidence-based, cost-benefit analysis performed by 1898 & Co. 1898 & Co. determined the relative values of the projects for each of the proposed measures and the corresponding prioritization and optimization of implementation.[13]

Q. Did SPS coordinate with federal, state, or local government programs?

A. No. The proposed measure in this docket contains two separate programs, Mainline Automated Reclosing Deployment and Lateral Reclosing Deployment, which are not dependent upon or coordinated with federal, state, or other government programs.[14] However, SPS plans to evaluate opportunities to secure state grant funding through the Texas Energy Fund (TEF) for portions of the cost of resiliency investment.[15]

V. RESILIENCY MEASURE ANALYSIS

Q. How does the Commission's rule define a resiliency event?

[13] Application at 3.

[14] *Id.*, Attachment A at 53

[15] Direct Testimony of Brooke A. Trammell on behalf of Southwestern Public Service Company at 26 (Dec. 30, 2024).

A. According to 16 TAC § 25.62(b)(3), a resiliency event is defined as an event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems.[16] A resiliency event is not primarily associated with resource adequacy or an electric utility's ability to deliver power to load under normal operating conditions.[17]

Q. Has SPS's service territory experienced resiliency events as defined by 16 TAC § 25.62(b)(3)?

A. Yes. SPS relied on data collected from the National Oceanic and Atmospheric Administration (NOAA) database for counties within the service territory. The data indicates that there were 3,443 weather events from 1998 to 2023.[18] Of this data, the vast majority of events in the SPS service territory were tornados, straight-line wind damage, severe winter weather, and flash floods.[19] 1898 & Co. also noted there has been a significant increase in wildfire risk over the last 50 years.[20]

Q. Please explain how you have provided your analysis for the measure you are addressing.

A. My analysis examined the one distribution measure, the Distribution System Protection Modernization. This measure contains two programs: the Mainline Automated Reclosing

[16] 16 TAC §25.62(b)(3).

[17] *Id.*

[18] Application, 1898 Attachment A at 57.

[19] *Id.*, at 58.

[20] Application, Attachment A at 48.

Deployment and the Lateral Reclosing Deployment. In my analysis, I provide a brief description and cost for each measure and discuss the anticipated benefits the measures are intended to address, and alternatives considered. Both programs require the use of basic distribution materials such as reclosers, mid-point (tie) reclosers, non-expulsion-type fuses, and other accessories. [21]

A. DISTRIBUTION SYSTEM PROTECTION MODERNIZATION

Q. For the Distribution System Protection Modernization measure, please explain how each program is designed to improve distribution system resiliency and provide the estimated costs.

A. **Mainline Automated Reclosing Deployment:** For the Mainline Automated Reclosing Deployment program, 1898 & Co. evaluated 459 circuits.[22] The cost is approximately $79.7 million and has quantified benefits in excess of cost (BCR = 4.2).[23]

Lateral Reclosing Deployment: For the Lateral Reclosing Deployment program, the second program in the Distribution System Protection Modernization measure, 1898 & Co. evaluated 10,800 protection zones.[24] The cost is approximately $2.0 million and has quantified benefits in excess of cost (BCR = 1.8).[25]

Segmenting the distribution circuits using the strategies of these two programs can isolate

[21] Application, Attachment A at 56-60.

[22] Application, 1898 Attachment A at 135.

[23] Application at 4.

[24] Direct Testimony of Jason D. De Stigter on behalf of Southwestern Public Service Company at 26 (Dec. 30, 2024).

[25] Application at 4.

faults quickly and succinctly allowing healthy portions of the distribution circuits to be left energized or become reenergized from the unhealthy portion of that circuit. This will decrease the CMI impact, $CMI, and help the SPS Control Room determine quickly where the fault occurred before rolling a field crew.[26]

Q. For the Distribution System Protection Modernization measure, please identify the type of events the measure is intended to address and provide the anticipated benefits.

A. In the direct testimony of Mr. Adrian Rodriguez, he states the SPS territory is subject to unpredictable, intense, and, often times, compounding weather events, ranging from icing and blizzards to extreme heat and drought, flooding, high winds, and tornadoes.[27] These weather conditions, especially drought and high winds, also increase the likelihood and destructiveness of wildfires in the region.[28]

Mainline Automated Reclosing Deployment: For the Mainline Automated Reclosing Deployment program, 1898 & Co. evaluated 459 circuits. Their evaluation shows an expected decrease in CMI of approximately 37%.[29]

Lateral Reclosing Deployment: For the Lateral Reclosing Deployment program, the second program in the Distribution System Protection Modernization measure, 1898 & Co. evaluated 10,800 protection zones. Their evaluation shows an expected decrease in CMI

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[26] Application, Attachment A 57-59.

[27] Direct Testimony of Adrian Rodriguez on behalf of Southwestern Public Service Company at 9 (Dec. 30, 2024)

[28] *Id.* at 9.

[29] Application, at 4.

of approximately 21%.[30]

Q. Did SPS consider alternatives to the Distribution System Protection Modernization measure?

A. Yes. SPS and 1898 & Co. considered various alternatives. The alternatives were evaluated, and the appropriate alternatives were selected and applied to each feeder. [31]

Q. What is your recommendation regarding the Distribution System Protection Modernization measure?

A. I recommend both Mainline Automated Reclosing Deployment and Lateral Reclosing Deployment programs of the Distribution System Protection Modernization measure be approved. These programs in accompaniment with the other measures mentioned in the SPS SPR are designed to improve the resiliency of the overhead distribution system. Applying modern technology and proven devices will improve the resiliency of the SPS overhead distribution system to resiliency events. As mentioned previously, SPS also adopted the use of new design and construction standards which go above the minimum recommendations of the NESC thereby providing additional resiliency improvements to the modern technology and proven devices they wish to install into their distribution system. This plan is outlined over a three-year period (2025-2028) and will reduce the outage frequency and restoration time, thereby reducing CMI caused by major storm events.

VI. CONCLUSIONS

[30] Application at 4.

[31] Application, 1898 Attachment A at 139-140.

Q. Of all the proposed measures you addressed, which do you recommend for approval and why?

A. I recommend both the Mainline Automated Reclosing Deployment Program and Lateral Reclosing Deployment Program, which fall under the Distribution System Protection Modernization measure be approved for the following reasons:

(1) Both programs are designed to enhance system resiliency;

(2) 1898 & Co. utilized a resilience-based prioritization process to identify, prioritize, and perform benefit-cost modeling to support SPS's measures;

(3) Both programs have an implementation timeline of three years;

(4) Both the Mainline Automated Reclosing Deployment Program and Lateral Reclosing Deployment Program are projected to decrease storm impacts after major weather events and decrease CMI impacts 37% and 21% respectively. [32]

(5) The Mainline Automated Reclosing Deployment Program and Lateral Reclosing Deployment Program are projected to yield BCRs of 4.2 and 1.8 respectively by decreasing the occurrence and reducing the recovery time of the negative results from unwanted resiliency events.[33]

Q. Are there any other recommendations or concerns regarding any of measures discussed for approval?

A. Yes. The Resiliency Plan complements existing Commission Rules, Southwest Power

[32] Application, at 4.

[33] *Id.*, at 4.

Pool (SPP) Protocols, SPP Planning Guide, SPP Operating Guide, and NERC Reliability Requirements. Should all or partial recommendations of this Resiliency Plan be approved, I recommend the Commission order SPS to abide by all applicable Commission Rules, SPP protocols, SPP Planning Guide, SPP Operating Guide and NERC Reliability standards.

Q. Does this conclude your testimony?

A. Yes

Attachment MN-1
Qualifications of Mike Noth

Academic Experience

Bachelor of Science in Engineering: The University of Texas - Arlington, Arlington, Texas

Major: Electrical Engineering

Professional Experience

Professional Engineer

Oregon PE # 58604PE (expired)

Texas PE # 54092 (active - expires March 2025)

Engineer VI Public Utility Commission of Texas (PUC)	November 2024 - Present
Power System Managing Engineer Austin Energy	August 2017 – November 2024
Director of Enterprise Engineering The Lower Colorado River Authority	March 2008 – August 2017
Electrical Manager S. Kanetzky Engineering, LLC	October 2006 – March 2008
Electrical Manager Samsung Austin Semiconductor	July 2001 – October 2006
Electrical Manager Hyundai Semiconductor America	March 1997 – July 2001
Engineering Technician Texas Instruments	August 1984 – February 1997

General Description:

Perform advanced engineering work on a broad range of infrastructure issues. Work involves applying engineering principles to evaluate engineering and technical issues to include identifying, analyzing, and providing recommendations regarding issues related to facility design, planning, construction, start-ups, operations, maintenance, and root cause analysis in the electric and semiconductor industries.

Essential Functions:

• Identify, analyze, and provide recommendations on issues relating to electric infrastructure planning, design, construction, operations, and maintenance.

• Perform root cause analysis on system failures using many different root cause methodologies.

• Prepare written testimony for filing in contested proceedings, including certificate of convenience and necessity, and rate proceedings.