FERC IS HOLDING UTILITY TRANSMISSION PROJECTS TO A HIGHER STANDARD FOR COST AND INCENTIVE RECOVERY

Summary

The Federal Energy Regulatory Commission ("FERC" or "Commission"), when determining recovery of utility transmission infrastructure investment costs and incentives, is raising the evaluation criteria from management prudence and evolving to "best practices". FERC has also opened up the transmission market leaving utilities to compete with non-incumbent developers in what has traditionally been their own territory. Utilities are now faced with the challenge to take prompt action to increase their proficiency with the management of their transmission infrastructure capital projects in order to satisfy FERC and state regulatory commissions and to diminish the effect of competition.

To the benefit of all stakeholders, utilities embarking on transmission infrastructure projects should proactively take measures to improve their management and cost efficiency in order to increase the likelihood of cost recovery and protect their transmission territory. Utilities should strive to strike a balance between shareholder returns and the cost to rate payers. Creating this balance will be a most challenging task for utility management. These challenges can be successfully resolved if the utilities proactively invest in appropriate measures that center on: past rate case experience; formal assessment of current management practices against industry "best practices" exemplified by the Project Management Institute, Association for the Advancement of Cost Engineering, and American National Standards Institute; demonstrating during the project life-cycle the ability to anticipate and avoid problems; preparing quality cost estimates with appropriate levels of management reserve (design maturity) and contingency for risk and uncertainty; efficiently delivering quality solutions at a competitive price; and lastly, documentation of key decisions, alternatives considered, and actions taken. The consequences of not recognizing and proactively addressing the known challenges will likely leave a utility to suffer unintended consequences from increased Federal and State regulatory scrutiny.

1.0 INTRODUCTION

Much of the electric transmission infrastructure across the United States is antiquated and insufficient to meet forecast demands. Generally the transmission grid was built in the 1960's through the 1980's and needs focused attention. Recognizing the problem, the United States Congress and the FERC are proactively addressing the need for expanding investment in the transmission infrastructure in order to meet the expected 50% growth in consumer demand over the next two decades.[1] These regulatory efforts center on striving to provide financial incentives for utilities to invest in transmission infrastructure projects that will help improve the reliability of the bulk power transmission system and reduce the cost of

[1] FERC Order 679: Promoting Transmission Investment through Pricing Reform, issued July 20, 2006

delivered power to customers by reducing transmission congestion. Notwithstanding, there appears to be an unresolved conflict between FERC's ruling in FERC Order 679 and specifics of Section 219 of the Federal Power Act creating some uncertainty.[2]

FERC is offering utilities three forms of incentives to invest in transmission infrastructure projects, including: 1.) a base Return on Equity (ROE) centered on discounted cash flow (DCF); 2.) risk reduction incentives to address financial and regulatory risks not accounted for in the base ROE; and 3.) other ROE incentives.[3] FERC requirements for utilities to recover these incentives are evolving beyond management prudence and becoming more prescriptive and challenging. In order to recover incentive ROEs, FERC now expects utilities to proactively identify risks and challenges; minimize risks through means such as implementing project management and procurement "best practices"; consider alternatives in the planning process; and commit to a cost estimate.[4]

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The recent investment in transmission projects is large and has been rapidly growing. Edison Electric Institute ("EEI") members reported investing approximately $7.6 billion in 2005 at the advent of the Energy Policy Act of 2005 (the "ACT").[5] EEI members reported investments of approximately $10.7 billion in transmission projects in 2010 and $11.1 billion in 2011.[6] Participating EEI members are forecasting a planned investment through 2015 of $54.8 billion, peaking in 2013 at $15.2 billion.[7] Subsequent to Congress passing the Act, the annual EEI membership reporting investment in transmission infrastructure projects has grown 100% through 2013. These transmission projects address interstate transmission needs ($26.5 billion); integration of renewable resources ($38.7 billion); and large multi-partner projects ($29.1 billion).[8]

The current exponential growth of investment in the transmission industry mirrors the challenges of prior energy industry periods of

[2] In the Energy Policy Act of 2005 (the "Act"), Congress added Section 219 to the Federal Power Act. In the Act, FERC was charged by Congress to establish by rule, incentive-based, (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by **ensuring reliability and reducing the cost** of delivered power by reducing transmission congestion. [emphasis added] FERC has ruled in FERC Order 679 that any investment made in, or costs incurred for, transmission infrastructure after August 8, 2005 that **ensures reliability or lowers the cost** of delivered power by reducing transmission congestion will be eligible for incentive-based rate treatments under this Rule." [emphasis added]

[3] FERC Policy Statement RM11-26-000, Promoting Transmission Investment Through Pricing Reform, Issued November 15, 2012

[4] FERC Policy Statement RM11-26-000, Promoting Transmission Investment Through Pricing Reform, Issued November 15, 2012

[5] Transmission Projects: At A Glance, Edison Electric Institute, page xi, March 2012

[6] Transmission Projects: At A Glance, Edison Electric Institute, page v, March 2013

[7] Transmission Projects: At A Glance, Edison Electric Institute, page v, March 2013

[8] Transmission Projects: At A Glance, Edison Electric Institute, page iii, March 2013

high demand for projects/programs. Examples include the nuclear plant investment period of the 1970's through the 1980's, the gas-turbine plant build out of the 1990's through the early 2000's, and the environmental projects (FGD/SCR/Hg) expansionary period of the early to mid-2000's in fossil generation. Each of these prior mass expansionary periods experienced increasing costs, schedule and equipment delivery delays, and unique challenges due to multiple market forces. These circumstances exacerbated the supply chain of A/E firms, contractors, material and equipment suppliers, strained the cash flows of utilities, utilities management, and the regulatory authorities.

2.0 REGULATORY BACKGROUND

FERC is an independent regulatory agency within the United States Department of Energy ("DOE") that regulates among other things, the interstate transmission of electricity, natural gas, and oil. The Commission is composed of up to five (5) commissioners who are appointed by the President of the United States with the advice and consent of the Senate. Commissioners serve five-year terms, and have an equal vote on regulatory matters.

The Energy Policy Act of 2005, signed into law in August 2005, changed US energy policy by adding a new section 219 to the Federal Power Act.[9] The law required FERC to develop a rule for incentive-based (including performance-based) rate treatments for transmission of electric energy in interstate commerce by public utilities to the benefit of consumers by ensuring reliability and reducing cost of delivered power by reducing transmission congestion. The purpose of the law was to:

- **Promote reliable and economically efficient transmission and generation of electricity by promoting capital investment;**
- **Provide a Return on Equity** to attract new investment in transmission facilities;
- **Encourage deployment of transmission technologies** to increase capacity, efficiency, and operations of existing transmission facilities;
- **Allow for recovery of all <u>prudently incurred costs</u>** necessary to comply with mandatory reliability standards pursuant to section 215;
- **Allow for recovery of all <u>prudently incurred costs</u>** related to transmission infrastructure development pursuant to section 216; and
- **Provide incentives** for joining a Transmission Organization.

The Commission issued FERC Order No. 679 in July 2006 to implement the new section 219 to the Federal Power Act. FERC Order No. 679 established rules for incentive-based rate treatments for utility investment in electric transmission infrastructure for customer benefit. The Commission's intent is to encourage investment or otherwise remove impediments in needed new transmission projects to connect new generation sources, reduce congestion, improve reliability, or to lower the delivered cost of power.[10] The Commission is responsible for determining the level of Return on Equity (ROE) on a case-by-case basis. The Commission has no single formula for incentive recovery, placing responsibility on each applicant to demonstrate that there is a relationship between the incentives sought and the investment being made or costs incurred after August 2005 when the Energy Policy Act of 2005 was passed.

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[9] The Federal Power Act was initially enacted into law in 1920 as the Federal Water Power Act. The law was later renamed the Federal Power Act in 1935 when the Federal Power Commission (now the Federal Energy Regulatory Commission) was expanded to include interstate electricity transmission.

[10] See Footnote No. 2.

The Commission traditionally establishes a utility company's base ROE using a discounted cash flow (DCF) analysis applied to a selected proxy group made up of representative firms of comparable risk. In FERC Order 679, the Commission adopted further risk reducing measures to lower the financial and regulatory risk associated with a transmission investment not accounted for in the base ROE. These three (3) risk reducing measures focused on up-front regulatory certainty, rate stability, and improved cash flow consisting of the ability to:

1. Increase from 50% to 100% of prudently incurred transmission-related Construction Work in Progress (CWIP) in the rate base in states where it is statutorily allowed;
2. Expense prudently incurred "pre-commercial" costs (instead of capitalizing these costs and earning a return) as a way to provide up-front regulatory certainty; and
3. Recover 100% of prudently incurred costs of transmission facilities that are abandoned for reasons beyond the utility's control.

To provide additional inducements, the Commission also adopted, on a case-by-case basis, further incentive ROEs to utilities that invest in transmission projects that result in reduced congestion, improved reliability, or joining a Transmission Organization.

FERC has recently provided guidance, clarity, and further transparency regarding its evaluation of transmission incentives issued under Section 219 of the Federal Power Act and FERC Order No. 679. In November 2012 FERC issued Policy Statement No. RM11-26-000 in which FERC portrays what is "**expected"** [emphasis added] of applicants including:

1. Take all reasonable steps to identify and to mitigate the risks associated with a transmission project;
2. Request those incentives, designed to reduce the risk of a project, before seeking an incentive ROE based on a project's risks and challenges;
3. Applicants seeking an incentive ROE based on a project's risks and challenges to make the following four (4) showings as part of their application for that incentive: identification of risks and challenges; minimization of risks; consideration of alternatives; and commitment to cost estimates;
4. Demonstrate that the proposed project faces risks and challenges that are not either already accounted for in the applicant's base ROE or addressed through risk-reducing incentives;
5. Demonstrate that the applicant is taking appropriate steps and using appropriate mechanisms to minimize its risks during project development;
6. Demonstrate that alternatives to the project have been, or will be, considered in either a relevant transmission planning process or other appropriate forum; and
7. Commit to limiting the application of an incentive ROE based on a project's risks and challenges to a cost estimate.

FERC reaffirmed that it will authorize a "Base" ROE utilizing a range of reasonableness from a discounted cash flow (DCF) to account for many of a transmission project's risks. In addition, FERC affirmed that it will authorize "Risk-Reducing" incentives for risks in a transmission project investment not accounted for in the Base ROE by providing regulatory certainty, rate stability, and improved cash flow by allowing a utility:

- Recovery of 100% of <u>prudently incurred CWIP;</u>
- Recovery of 100% of <u>prudently incurred "pre-commercial" costs</u> as an expense or as a regulatory asset; and
- Recovery of 100% of <u>prudently incurred costs of abandon transmission facilities</u> that are abandoned for reasons beyond the applicant's control.

In addition to the Base ROE and Risk Reducing incentives, FERC affirmed that it would authorize additional "Incentive" ROEs based on a project's unique risks and challenges. Applicants would be allowed flexibility to demonstrate need for Incentive ROEs.

In its Policy Statement, FERC offered as an example of risk mitigation actions, the application of "risk-reducing incentives… or mitigating costs by implementing best practices in their project management and procurement procedures". In addition, applicants are expected, as a possible prescribed outcome, to commit to limiting the incentive ROE based on a project's risks and uncertainties to a cost estimate relied upon at the time of a Regional Transmission Organization project approval, due to "concerns" about the effects of allowing transmission incentives to be applied to costs above and beyond the estimated costs.

In its policy statement, FERC provided four (4) examples of projects that may warrant incentive ROE based on a project's risk and challenges not otherwise accounted for, including projects that:

1. Relieve chronic or severe grid congestion that has had demonstrated cost impacts to consumers;
2. Unlock location constrained generation resources that previously had limited or no access to the wholesale electricity markets;
3. Apply new technologies to facilitate more efficient and reliable usage and operation of existing or new facilities; and
4. Provide demonstrated consumer benefits by making the transmission grid more efficient, reliable, and cost effective.

3.0 COST AND INCENTIVE RECOVERY

3.1 Management Prudence

One of the greatest challenges a utility faces is recovery of its costs and incentives for investment in major capital projects. Utilities have historically had to meet some standard of management prudence in order to recover its incurred costs from its ratepayers.

The majority of jurisdictions conducting prudence reviews have adopted a common definition of prudence — a test of reasonableness of the decision under all of the circumstances known at the time.[11] One example is Missouri, where the Missouri Public Service Commission has defined prudence as:

> *[The] company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company… In accepting a reasonable care standard, the Commission does not adopt a standard of perfection. Perfection relies on hindsight. Under the reasonableness standard relevant factors to consider are the manner and timeliness in which problems were recognized and addressed. Perfection would require a trouble-free project.*[12]

At or near the completion of large capital intensive projects, utilities have generally had to undergo a resource intensive regulatory initiated prudence review. These prudence reviews are generally aimed at retrospectively analyzing the decision making process and the activities that occurred during the project life-cycle. Major construction project prudence reviews predictably focus on key decisions such as A/E and key vendor selection, contracting strategy, major technical/design features, construction approach, and schedule delays/cost overruns from initial estimates.

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[11] New Day for Prudence, Nielson, Galloway, and Whitney, Fortnightly Magazine, December 2009

[12] Union Electric, 27 Mo. PSC (N.S.) 183, 194 (quoting Consolidated Edison Co. of New York, 45 P.U.R.4th 331 (1982) (internal quotations omitted)

Prudence reviews became high stakes proceedings for large utility investments in major construction projects beginning in the late 1970's and continuing through the 1990's. Beginning in the 1970's, there began an informal paradigm shift, from an historical practice of accepting incurred time and materials, to moving to a lump sum price based on early estimates, with limited rules regarding cost recovery challenges by State commissions. As a result, prudence-related rate recovery disallowances soared. U.S. utilities and their respective shareholders lost billions of dollars when commissions made determinations of imprudent spending and project management. Utilities were caught in the midst of regulatory changes that demanded plant design changes, and ever-increasing costs for which reasonableness could not be accurately documented.[13] According to a 2005 Lyon and Mayo study published in the Rand Journal of Economics, between 1981 and 1991 there were more than $19 billion of prudence-related rate recovery disallowances associated with 36 new power plant construction projects. More than 95 percent of these disallowances related to nuclear power plant construction schedule delays and cost overruns. A 1986 DOE review of twelve (12) nuclear projects found that the average prudence disallowance for these plants was nearly 16 percent of the cost of construction.[14]

3.2 *Additional Higher Standards for Incentive ROEs*

If utilities expect to fully recover cost and receive additional investment incentives granted by FERC, they will be held to a standard higher than "management prudence". FERC is proposing to hold utilities to the standard of "best practices" in project management and procurement. In addition, utilities may be expected to commit to limiting the Incentive ROE based on a project's risks and uncertainties to a project cost estimate relied upon at the time of project approval.

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Project management activities on transmission projects should begin with the utility's strategic decision to proceed with a transmission project and end with the transitioning of the completed project to others responsible for its operation and maintenance. These long life-cycle projects are comprised of multifaceted tasks, integrated teams, complex decisions, numerous stakeholders, regulatory scrutiny, large sums of money and resources, uncertainty, risks and change.

This environment places further challenges and burdens of proof on the utility requesting any additional investment incentives. Utilities will most likely have to demonstrate proficiency in all aspects of project management functions that define the overall direction and coordination of project implementation tasks/functional areas through the life-cycle, including scope, cost estimating, planning and scheduling, risk management, contract management, procurement, accounting, resource management, change management and quality.

3.3 *Project Management and Procurement "Best Practices"*

The standard of excellence in project management and procurement is collectively captured and promoted by several well recognized industry leading organizations

[13] New Day for Prudence, Nielson, Galloway, and Whitney, Fortnightly Magazine, December 2009

[14] "Prudence Revisited", Electric Light & Power, June 01, 2007

including the Project Management Institute ("PMI"), the Association for the Advancement of Cost Engineering ("AACE"), and the American National Standards Institute ("ANSI").

3.3.1 Project Management Institute ("PMI")

The most wide-ranging standard for project management practices is PMI. PMI is a worldwide advocate for project management and is globally recognized for its project management standards, certification process, training and education, research, and governance.[15] PMI's global standards provide guidelines, rules and characteristics for project, program, and portfolio management. PMI views project management to be a "profession". PMI publishes and maintains the Project Management Body of Knowledge ("PMBOK") as a sum of knowledge within the profession of project management.[16] The PMBOK reflects the collaboration and knowledge of project management leaders who deliver results and serves as a reference for what is generally accepted as "good practices" that are applicable to a broad range of industries and most projects. The PMBOK defines forty four (44) project management processes organized into nine (9) project management areas:

1. Integration Management
2. Scope Management
3. Time Management
4. Cost Management
5. Quality Management
6. Human Resource Management
7. Communications Management
8. Risk Management, and
9. Procurement Management

3.3.2 AACE International ("AACE")

Applying a concentrated focus on project control, a subset of project management, AACE provides recommended best practices for project cost estimating, cost engineering, planning and scheduling, project control, and risk management. AACE, founded in 1956 is dedicated to furthering the concepts of total cost management and cost engineering.[17]

AACE defines total cost management to be the effective application of professional and technical expertise to plan and control resources, costs, profitability, and risk. AACE promotes best practices for cost management professionals through publication of the *Total Cost Management®* ("TCM") Framework.[18] The TCM Framework, applicable to all industries, explains each practice area of the cost engineering field in the context of its relationship to other practice areas. AACE considers the TCM Framework to be a cornerstone technical document that joins the current body of knowledge literature for related fields such as project management, operations management, and management accounting.

3.3.3 ANSI/EIA Standard 748: Earned Value Management Systems ("EVMS")

The American National Standards Institute ("ANSI") and the Electronic Industries Alliance ("EIA") jointly provides very focused project management "best practices" for integrated project management and project performance measurement using "earned value" ("EV") principles. Earned value management ("EVM") is the accepted industry project management methodology that relies on EV principles and uses the concept of "completed work" as the primary tool to evaluate and control cost, schedule, and technical performance. The benefits of EVM can only be realized through comprehensive planning and the establishment, and disciplined maintenance of the project baseline documentation (scope, schedule,

[15] www.pmi.org

[16] A Guide to the Project Management Body of Knowledge (PMBOK Guide)- Fifth Edition, 2013

[17] www.aace.org

[18] Total Cost Management Framework, First Ed, revised, 2012

budget, and risk). ANSI and the EIA published Standard 748 on Earned Value Management Systems ("EVMS").[19] ANSI/EIA Standard 748 is intended to serve as a guide for the establishment of an integrated management system with coordination of work scope, schedule, and cost objectives, and the application of EV methods for program or enterprise planning and control. EVMS covers a company's integrated set of policies, procedures, and practices to support program and project management as a decision enhancing tool, and a critical component of risk management.

ANSI/EIA 748 has organized EVMS standards into five (5) summary guidelines and thirty two (32) criteria that are essential for use in establishing and applying an integrated EVMS. The five (5) summary guidelines are:

1. Organization
2. Planning, Scheduling, and Budgeting
3. Accounting Considerations
4. Analysis and Management Reports, and
5. Revisions and Data Maintenance.

These five (5) summary guidelines and thirty two (32) criteria provide flexibility and scalability so EVMS principals can be applied to any program regardless of size and complexity, to realize the benefits of earned value management. The National Defense Industrial Association (NDIA) Program Management Systems Committee ("PMSC") published in 2005 the NDIA PMSC ANSI/EIA-748-A Standard for Earned Value Management Systems Intent Guide which provides additional useful insight into each of the thirty two (32) criteria of ANSI/EIA-748.[20]

[19] "Earned Value Management Systems", EIA Standard, ANSI/EIA-748.

[20] National Defense Industrial Association (NDIA) Program Management Systems Committee (PMSC) ANSI/EIA-748-A Standard for Earned Value Management Systems Intent Guide, January 2005

The United States Office of Management and Budget ("OMB") recognized EVM as an important project management tool to mitigate risks on major acquisition capital projects. [21] In the late 1990's OMB began to mandate that federal agencies use EVM on major acquisition capital projects where cost, schedule, and performance goals are identified and measured using an earned value management system. On very large dollar capital projects, most federal agencies now require certification of its contractors earned value management system to the standards set forth in ANSI/EIA 748.

3.3.4 Implementing "Best Practices" in Transmission Projects

Successful executions of large complex projects apply a blend of project management "best practices" exemplified by PMI, AACE, and ANSI 748 in conjunction with other management techniques.

For success, project management "best practice" must embrace essential EVM elements including:

- At the beginning of the project life-cycle, establish a concise project management plan that includes development of and rigorously adhering to an integrated baseline for scope, estimate, schedule, and risk using a deliverable based work breakdown structure aligned with the organizational breakdown structure;
- Comprehensive integrated baseline change management and alignment (scope, cost, schedule, and risk) programs;
- Measure accomplishments and capture any actual and incurred costs consistent

[21] Capital Programming Guide, Supplement to Office of Management and Budget Circular A-11: Planning, Budgeting, and Acquisition of Capital Assets, July 2102

with the integrated baseline documents for periodic (at least monthly) variance analysis and reporting at both detailed and summary levels; and

- Commitment to EVM across the entire project (key vendors, suppliers, contractors, and subcontractors) and the sponsoring company organization.

Multiple successful transmission implementation entities are starting to embrace project management best practices using EVM and EVMS principles on their transmission projects.

A compelling example of the importance of EVM is the Montana Alberta Tie Line ("MATL") transmission line project by the Western Area Power Administration ("WAPA" or "Western").[22] This project was recently reviewed by the US Department of Energy ("DOE") Inspector General ("DOE IG"). The DOE IG found that "because of a variety of problems, the project is estimated to be 2 years behind schedule and $70 million over budget; essentially out of funds; and, currently at a standstill, with no progress being made."[23] In its findings, the DOE IG reports "We believe that the project would have benefited had Western required that an earned value management system be implemented by MATL at the beginning of the project to firmly establish expectations." Western has now committed to following its own specific guidelines in conjunction with principles set forth in DOE Order 413.3B which calls for EVM compliance with ANSI/EIA 748.

[22] WAPA is a Federal Agency under the US Department of Energy that markets and transmits wholesale electrical power across a 15 state marketing area.

[23] Management Alert, Western Area Power Administration's Control and Administration of American Recovery and Reinvestment Act Borrowing Authority, U.S. Department of Energy Office of Inspector General, Office of Audits and Inspections, dated November 2011.

4.0 THE FUTURE AND RECOMENDATIONS

With the large investment dollars at stake, all transmission development entities should expect future increases in regulatory scrutiny and requirements for incentive and cost recovery. As FERC continues to execute its cost recovery and incentive policies and balance the benefits of transmission with the costs to rate payers, expect incentive recovery thresholds to continue to be raised as more project applications are submitted to FERC and state commissions for approval.

Utility transmission projects will be subjected to management prudence reviews by FERC, state and local regulatory authorities, as have been previously performed on a multitude of major capital projects during the last several decades. Additionally, many expect to see an increase in the frequency and complexity of rate cases necessary to recover the costs of these new investments.[24] FERC and state regulatory commissions will most likely require these management prudence reviews be conducted to insure that utilities can demonstrate that they are only seeking recovery of prudently incurred costs and Incentive ROEs.

Utilities should take measures to insure maximizing their cost recovery from FERC, state, and local jurisdictions. If a utility expects to receive full recovery of its costs and associated incentives, it should start early in the transmission project life-cycle in order to prepare for the unavoidable heightened regulatory scrutiny and requirements. Proactive utilities will take timely steps to evaluate and move their project management and procurement processes and actions toward "best practices" and build the evidence file to capture and report how the journey benefits rate payers and other stakeholders.

[24] "Prudence Revisited", Electric Light & Power, June 01, 2007

However, utilities must strive to strike a balance between shareholder returns and the cost to rate payers. For these expensive and risk laden transmission projects, creating this balance will be a most challenging task for utility management.

Proactive utilities will take timely steps to evaluate and move their project management and procurement processes and actions toward "best practices" and build the evidence file to capture and report how the journey benefits rate payers and other stakeholders.

Utilities can meet these higher standards and be successful in cost recovery if they invest their time and effort in certain appropriate measures including but not limited to the following six (6) essential recommendations:

1. **Adopt a regulatory strategy and embrace the lessons learned from the utility rate case environment** dating back to the 1970's through the 1990's. Leverage utility management and subject matter experts who lived through this challenging period to understand and benefit from their experience.
2. **Recognize, formally evaluate, and document current capital project management and procurement practices against industry accepted "best practices".** Take appropriate steps to ensure that these practices are in line with industry accepted "best practices" based on EVM principles and focused on the needs of their individual circumstances and project requirements while minimizing cost overruns and schedule increases, thereby ultimately minimizing impacts to the rate payers. Where deficient, develop and document a process improvement program to achieve best practices. Reflect these practices in written integrated procedures, provide staff training, and perform periodic procedure and compliance audits.
3. **Demonstrate and document that during the entire project life-cycle reasonable steps have been taken to effectively manage the project by anticipating, planning for, and avoiding problems**, as well as minimizing the impacts of problems, if they occur. The project life-cycle begins with planning and continues through the discrete project elements of engineering, design, procurement, construction, startup testing, and transfers to operations. Success depends on effectively managing each element as well as managing the transition from one element to the next.
4. **Invest early in the appropriate level of project planning and conceptual engineering on each project to support the preparation of reliable and defensible technical scopes of work, cost estimates and basis of estimates, and schedules** that appropriately reflect the risk and uncertainty. Once approved, establish and maintain congruent scope, schedule and cost baselines, and capture, report and manage variances.
5. **Embrace a "Merchant Mentality" focused on efficiently delivering quality transmission infrastructure solutions at a competitive price.** Take appropriate steps to identify and analyze your competition and benchmark their performance as part of a formal continuous improvement strategy.
6. **Build an evidence file as the project unfolds** to capture contemporaneous documents regarding key decisions, any alternatives considered, and the basis for actions taken. Additional contemporaneous documentation should include current and projected market analysis regarding: AE firms and back-logs; construction firms availability; equipment and material constraints; labor availability; and benchmarking of competitor's efforts within the transmission development and execution market. Waiting until the end of the project to build the evidence file will deliver suboptimal results.

GATE 6 Solutions, Inc. ("**GATE 6")**, headquartered in the Atlanta, GA area**,** is a 27 year old project management and business management, and technical consulting practice. **GATE 6** and its team of seasoned professionals focus on achievement of project management excellence through efficiently harnessing the power of people, processes and technology. They are well respected for their broad based knowledge and demonstrated abilities to practically apply industry "best practices" in project management and procurement promulgated by the Project Management Institute, AACE, and ANSI/EIA 748. **GATE 6** has broad based project management experience and expertise in the utility industry throughout the capital project life-cycle encompassing conceptual planning, engineering and design, construction, operations & maintenance, decommissioning, and regulatory venues. In addition, **GATE 6** has direct experience in many of the utility rate making proceedings from the 1970's thru the present from various perspectives including the utilities, utility commissions, and co-owners. Additional information on GATE 6 can found at www.gate6solutions.com.

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(In addition, other subject matter experts from within and outside the utility industry were consulted in drafting this Whitepaper.)