JOINT NEW ENGLAND TRANSMISSION OWNER ASSET CONDITION PROCESS GUIDE

Version 1

October 23, 2024

Developed by:

Avangrid Networks

Central Maine Power Company

Maine Electric Power Company

The United Illuminating Company

Eversource Energy

The Connecticut Light and Power Company

NSTAR Electric Company

Public Service Company of New Hampshire

National Grid

New England Power Company

Rhode Island Energy

Narragansett Electric Company

Versant Power

Versant Power

Maine Electric Power Company

VT Transco

Vermont Electric Power Company

Contents

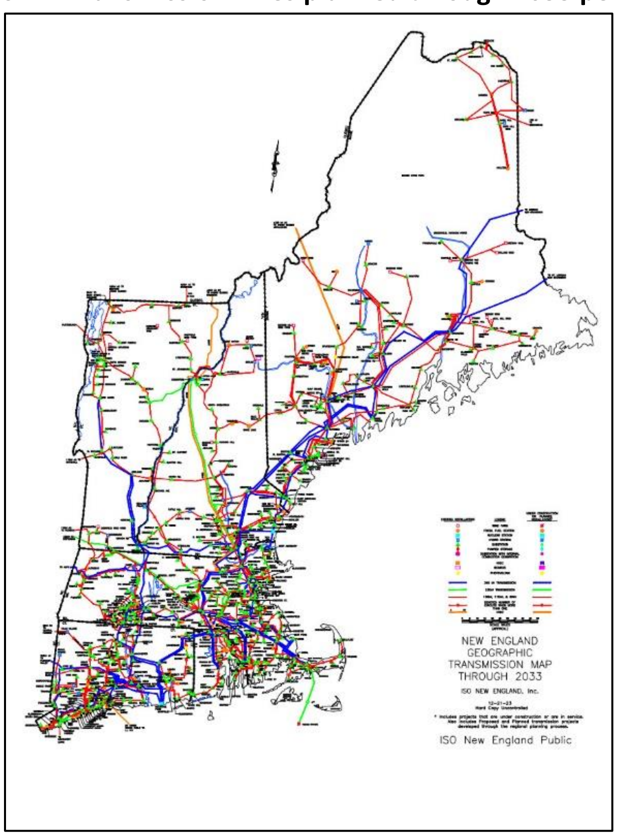
Executive Summary: Introduction and Purpose of the Guide

Background

The electric transmission grid in the six New England states (Connecticut, Massachusetts, Maine, New Hampshire, Rhode Island, and Vermont) is comprised of more than 9,000 miles of high-voltage transmission lines (69-kilovolts [kV] and above), with 13 transmission interconnections to the electric grids in New York State and eastern Canada. This regional transmission system consists of a network of predominantly overhead lines, but also includes underground cables as well as many substations and switching stations[1]. The transmission lines vary in voltage, including alternating current (AC) 69-kV, 115-kV, 138-kV, 230-kV, and 345-kV. Figure ES-1 provides a map of the New England transmission system planned through 2033.

Transmission line assets include conductors (wires, cables), shield wires, optical ground wire (OPGW), and infrastructure (structures, crossarms, insulators, switches, foundations for overhead lines; conduit, pipes, manholes, and vaults for underground lines). At substations, transmission assets include a range of equipment, depending on the type of station, and can include transformers, reactors, circuit breakers, bus work, relays, capacitors, switches, termination structures, control enclosures, protection and control equipment, power supply systems, physical and cyber security assets, duct bank and cable trench, etc.

Figure ES-1 – Transmission Lines planned through 2033 per ISO-NE



[1] In this document, the term “substations” is used to refer to both substations and switching stations.

Six transmission companies (collectively, the Transmission Owners)[2] own, operate, and maintain the majority of the Pool Transmission Facilities (PTF) in the New England region. This Guide was developed by the Transmission Owners to provide stakeholders with greater insights into the Transmission Owners' decision-making processes for asset condition projects, and the linkages between these decision-making processes and regional stakeholder engagement processes that occur through the ISO New England (ISO-NE) Planning Advisory Committee (PAC) and the New England Power Pool (NEPOOL) Reliability Committee (RC). This Guide is not intended to describe the processes used by the many smaller PTF owners across New England, which include municipal utilities and lighting plants, electric cooperatives, and smaller investor-owned utilities.

Each Transmission Owner regularly evaluates the condition of its electrical facilities, with the overarching objectives of ensuring the reliability of and minimizing risk to the transmission system, maximizing the life of transmission assets, minimizing costs, maintaining a safe operating environment, ensuring good environmental stewardship, while conforming to continually evolving regulatory requirements and standards. Allowing assets to deteriorate to the point of failure would pose unacceptable safety and reliability risks.

The Transmission Owners' transmission assets vary significantly in terms of characteristics such as age, voltage level, overhead structure configuration (e.g., wood pole, steel pole, steel lattice tower, laminated pole), conductor type, shield wire/OPGW, and underground cable category (e.g., high-pressure fluid filed [HPFF], high-pressure gas-filled [HPGF], solid dielectric cross-linked polyethylene [XLPE]). The environments in which the transmission assets are located also vary widely, ranging from the coastal zone to mountainous regions, with different areas exhibiting different ambient conditions (wind, salt air exposure, etc.) that can affect transmission asset life. As a result, whereas some transmission facilities that are more than 40-50 years old have no asset condition issues, others demonstrate a far shorter asset life, in some cases requiring replacement within less than 20 years after installation.

The Transmission Owners have an ongoing obligation to monitor their transmission assets and proactively implement required replacements or upgrades to maintain the reliability and integrity of the electric system. Such transmission asset condition projects may be warranted for a variety of reasons, specific to particular transmission lines or substations, such as, but not limited to:

- Replace infrastructure that has reached end of life due to exposure or damage.

- Upgrade infrastructure that consists of technology that has become unreliable or is no longer supported by manufacturers.

[2] The six New England Transmissions Owners are Avangrid Networks (Central Maine Power Company, Maine Electric Power Company, The United Illuminating Company), Eversource Energy (The Connecticut Light & Power Company, NSTAR Electric Company, Public Service Company of New Hampshire), National Grid (New England Power Company), Rhode Island Energy (Narragansett Electric Company), Versant Power (Versant Power, Maine Electric Power Company), and Vermont Transco (Vermont Electric Power).

- Upgrade infrastructure to meet current North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council Inc. (NPCC) requirements.

Within New England, all transmission projects undertaken by the Transmission Owners with an anticipated cost of $5 million or more are tracked on the ISO-NE Regional System Plan Project List, the ISO-NE Asset Condition List, or on the Transmission Owners Local System Plans. The Asset Condition List includes projects initiated by the Transmission Owners for a wide variety of reasons including, but not limited to, projects to address issues associated with aging, deteriorating, and/or unreliable assets. Other projects tracked on the Asset Condition List include upgrades to meet certain NERC and NPCC standards, as well as communication- and technology-related upgrades. Collectively, these projects are referred to as asset condition projects.

Purpose of the Guide

The Transmission Owners are responsible for continually monitoring and managing their transmission facilities and – as necessary – implementing electric transmission asset condition investments to replace degraded assets, to address performance issues, or to meet evolving standards and regulatory requirements. Each Transmission Owner has programs designed to track and monitor the condition of its transmission assets, to determine solutions to asset condition issues as they are identified, and to implement asset condition projects in order to cost-effectively support the continued reliability of the New England transmission system.

While each Transmission Owner devises unique asset condition strategies best suited to the demographics of its transmission facilities and the specific needs of its customers, all Transmission Owners broadly follow similar general practices for identifying and implementing asset condition projects. The purpose of this Joint New England Transmission Owner Asset Condition Process Guide (Guide) is to:

- Summarize the Transmission Owners' existing asset condition programs, including the processes typically used to monitor and evaluate the conditions of existing assets, determine when asset modifications/upgrades are necessary, and then to design, plan, permit, and construct such asset condition projects.

- Define the combined Transmission Owners' general practices for transmission asset condition projects, thereby providing transparency, for the benefit of the public as well as regulators, ISO-NE, other involved agencies, and other stakeholders, regarding the overall approach used to justify, plan, permit, and cost-effectively implement such projects.

As described in this Guide, the Transmission Owners' asset condition projects are planned and designed in conformance with applicable federal, regional and state requirements and involve agency coordination and stakeholder outreach.[3] The projects are coordinated with other known non-asset condition driven power system needs identified by ISO-NE.

Asset condition projects include those that are required to address not only physical deterioration (e.g., wood transmission poles that exhibit structural issues such as cracks, splits, insect or woodpecker damage), but also modifications required to meet current regulatory requirements or to replace obsolete equipment, among others. In planning asset condition projects, the Transmission Owners also must consider other factors such as changing load patterns, common industry practices, typical asset life cycles, balancing the risk of maintaining vs. replacing assets, and the potential for more frequent high-impact weather-related events (e.g., hurricanes, severe winter storms).

This Guide describes the general processes for evaluating, planning, and implementing asset condition projects. It identifies the primary steps and key decisions that are typically made as a Transmission Owner evaluates the conditions of its transmission facilities, identifies asset condition issues, determines and approves a preferred solution to address the issue, and then implements the asset condition project. The specific steps and processes followed by an individual Transmission Owner may vary depending on the Transmission Owner's own internal processes, the type of transmission facility, the nature of the solution, experience with past projects, and other factors. In this way, the process described in this Guide is not necessarily representative of any single Transmission Owners' processes for a particular project. Nonetheless, the processes described in this Guide are generally applicable to most asset condition projects developed by the Transmission Owners and presented to regional stakeholders.

Other Processes

In addition to the Transmission Owners' asset condition practices, other individual company processes govern or influence the development of asset condition projects. For example, the Transmission Owners employ internal financial governance processes and controls to establish and monitor budgets and forecasts for all capital transmission projects, including both asset condition projects and projects listed on the Regional System Plan Project List. In general, each Transmission Owner applies at least two funding steps as part of the planning process for most transmission projects:

1) ***Initial investigation budget*** – This typically involves the establishment of an initial project budget sufficient to fund preliminary investigations and scoping.

2) ***Full project budget*** – After the project is defined, the full scope and complete budget for a project is approved.

These budgeting steps are reflected in the processes described in this Guide. However, more complex projects may also be subject to interim funding milestones before a full project budget is established. Further, additional approvals may be required if the scope or anticipated cost of a project changes significantly from prior approvals. These interim and/or additional approvals are also reflected in the

[3] Some states already require annual reporting of planned Transmission projects: for instance, Maine requires a 5-year forecast of planned transmission projects whose cost exceed a percentage of Transmission plant value.

processes described in this Guide, although the implementation details may vary depending on the factors affecting individual projects. Projects are closely monitored and in the case of a significant change in cost or scope, re-approval internally is required ahead of a subsequent re-presentation to stakeholders.

The timing of the final approvals may vary depending on the nature of a project and may not always align precisely with the steps in the asset condition project process. For example, it may be possible to define a full budget for a relatively simple project based on limited design and engineering, while more complex projects may need to advance through additional project development steps before a full budget can be established.

Similarly, many of the stakeholder process requirements within the ISO-NE Open Access Transmission Tariff, Planning Procedures, and Transmission Planning Process Guide apply to all types of transmission projects, including asset condition projects. Planning Procedure No. 4 (PP4) and Appendix D and E of this Guide contain minimum requirements for stakeholder presentations. In general, the Transmission Owners present projects to ISO-NE and regional stakeholders once sufficient information (design, cost estimate, etc.) is available to meet the needs of the stakeholder process and ISO-NE requirements. However, the level of funding (and associated internal Transmission Owner funding milestones) that is required to develop sufficient information varies on a project-by-project basis.

Asset Condition Projects: Process Overview and Guide Organization

The Guide is organized to provide general information regarding the processes that the Transmission Owners presently use in decision-making regarding asset condition projects, as well as the standards and criteria that typically apply to the various stages involved in defining, designing, cost-estimating, and implementing asset condition projects.

As illustrated in Table ES-1, the Guide is divided into seven principal sections, corresponding to the primary steps in the process typically used to define and implement asset condition projects.

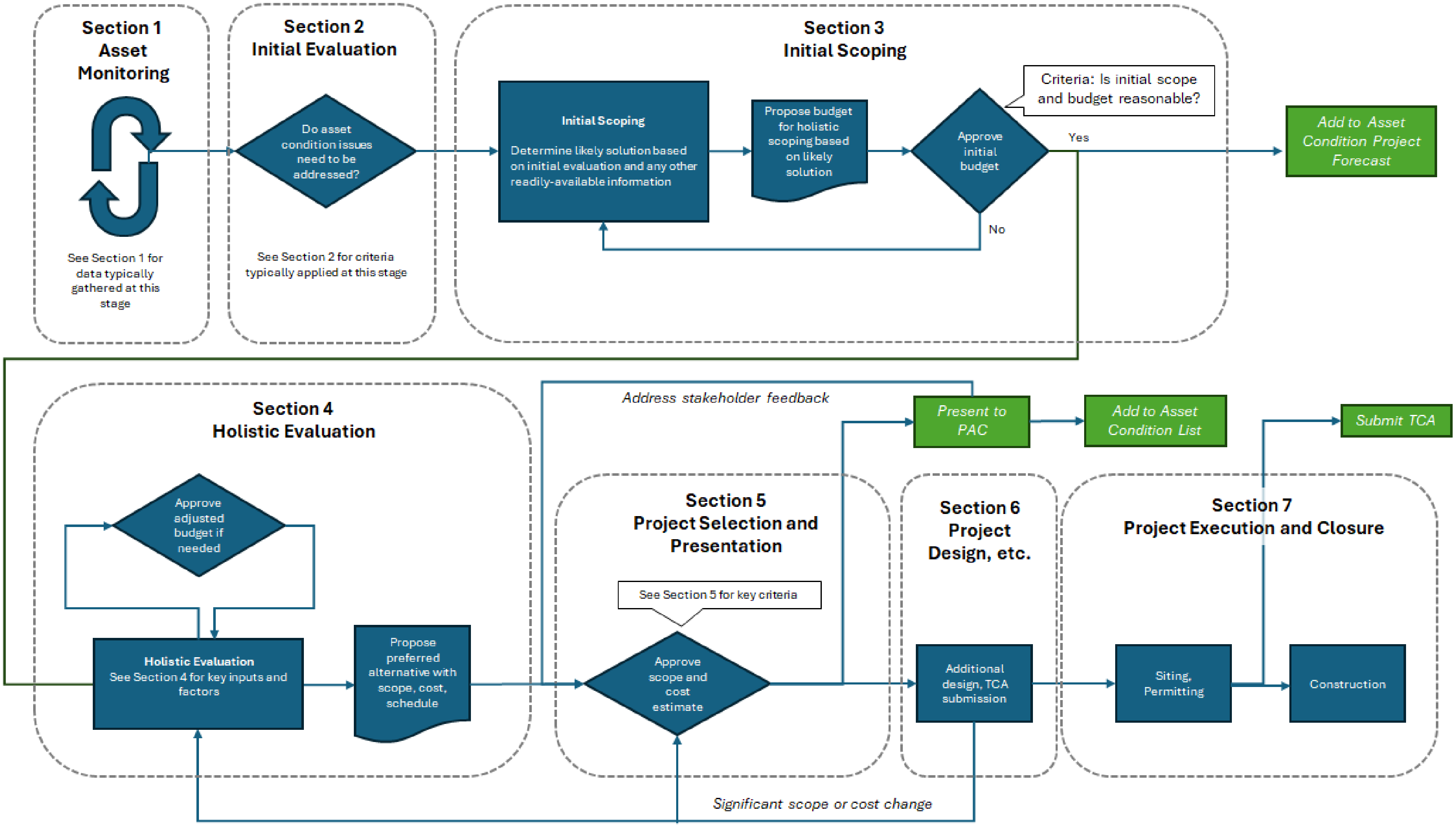
Figure ES-2 provides a more detailed flow chart of the process, while Table ES-1 summarizes how the seven steps align with internal Transmission Owner budgeting and project funding processes, stakeholder engagement processes, and the development of cost estimates. Other processes, such as environmental permitting, siting, and outreach to affected communities and stakeholders (which occur during Project Design and Execution) are also integral parts of each Transmission Owner’s project development process but are not shown in the table.

Appendix D provides additional details on the stakeholder transparency and review processes for asset condition projects, including the timing of presentations to the ISO-NE Planning Advisory Committee (PAC).

Table ES-1: Summary of Asset Condition Project Process

Primary Step	Budgeting/Funding Processes	ISO-NE/NEPOOL Stakeholder Process
1. Asset Monitoring – Conduct field inspections and other analyses to determine transmission asset condition and identify potential need for asset modification (i.e., asset condition project)	General O&M	N/A
2. Initial Evaluation – An initial project budget is usually established during, or at the completion of, this step. Projects at this step are added to the Transmission Owners' Asset Condition Project Forecast.	Initial project budget established; funding typically sufficient to cover holistic evaluation, but may be phased for more complex projects	Project added to Asset Condition Project Forecast
3. Scoping - Integrate the information collected during the asset monitoring phase and the need identified in the initial evaluation to develop an initial solution concept.		
4. Holistic Evaluation - In-depth assessment of the potential asset condition project is conducted and alternative solutions are presented for review.	Managed within initial project budget	N/A
5. Project Definition – A complete project budget is usually established during, or at the completion of, this step. Most asset condition projects are presented to PAC during this step.	Complete project budget established; funding typically sufficient to cover project execution, but may be phased for more complex projects	Project presented to PAC with Conceptual cost estimate (-25%/+50%). Two presentations recommended for projects exceeding $50 M. Re-presentation requirements apply if project cost increases 50% or more
6. Project Design – A multi-disciplinary team performs the final pre-construction studies and design.	Re-approval processes apply if project experiences significant scope or cost change	TCA submitted to ISO-NE prior to start of Major Construction, generally with Construction-level cost estimate (+/- 10%) TCA presented to NEPOOL Reliability Committee.
7. Project Execution and Closure	Budget managed or modified using TOs' internal controls	Re-presentation requirements apply if project cost increases 10% or more

Figure ES-2: Asset Condition Projects: Flowchart of Primary Process Steps



Section 1 Asset Monitoring

Overview

Asset monitoring is the process of collecting data regarding the condition and viability of transmission facilities. The Transmission Owners perform asset monitoring on an ongoing basis, using the process to identify and compile information regarding any potentially problematic assets, which are then targeted for initial evaluation (as described in Section 2 of this Guide).

Each of the Transmission Owners has a well-established asset monitoring program, which is tailored to the company's specific system and industry regulatory requirements. Overall, the asset monitoring programs are designed to provide data that aids in the evaluation of the condition of transmission lines (overhead and underground), as well as substations.

Asset monitoring is a continuous process; each Transmission Owner has personnel who perform transmission asset inspections and compile information regarding the inspection results. To assure a comprehensive review of transmission asset conditions, the companies use various methods, including but not limited to regularly scheduled on-ground and aerial inspections, analyses of an asset's performance history, on-line monitoring, and (as appropriate) equipment testing. Additionally, while performing this asset monitoring the Transmission Owner may perform life extension activities, such as painting towers, for example.

Asset monitoring forms the foundational process by which the Transmission Owners evaluate the transmission infrastructure, identify issues/assets at risk, and then make informed decisions regarding whether specific assets need to be repaired or replaced to maintain grid reliability and to comply with common industry practice. Asset monitoring is essential to detect asset flaws before they become failures. This is particularly challenging because each Transmission Owner's transmission portfolio consists of multiple components comprised of different materials, situated in a variety of locations with different exposures to environmental and man-made factors that can pose risks to or affect the asset conditions.

This section describes the various types of regular asset monitoring performed by the Transmission Owners, including the frequency with which such monitoring is completed. Tables 1-1 and 1-2 summarize the asset condition inspections performed by each of the Transmission Owners, for transmission lines (overhead and underground) and substations, respectively.

As technology advances, new transmission asset inspection methods become available. The Transmission Owners expect asset inspection methods in the transmission industry will continue to evolve and that each company will proactively integrate such technological advances into its asset monitoring program, as applicable. For example, drone/unmanned aerial vehicles (UAV) inspections of overhead lines have become more common in the past 10 years. Monitoring devices and sensor technologies continue to advance, potentially shifting the Transmission Owners' asset monitoring programs away from physical inspections and toward real-time data and algorithms to provide information on asset conditions.

Table 1-1: Transmission Owner Asset Condition Inspection Cycles – Overhead and Underground Transmission Lines*

Type of Inspection	Transmission Owner					
	Eversource	Avangrid	New England Power	VELCO	Versant Power	Rhode Island Energy
Ground Inspection	8 years: wood 16 years: steel	10 years (5 years if necessary based on previous inspection)	5 years (entire system) 10 years (wood pole inspect and treat) 20 years (steel structure coating/foundation/ footers)	8 years wood 20 years steel	Wood: 10 years Excavate and treat - 5 years re-treat (if in ROW) 6 Years Sound and bore (if on roadside) Steel 5 years	3-5 year cycle based on asset risk
Drone Inspections	Every year ≥ 200 kV 2 years < 200-kV	10 years (UI) 10 years (CMP if non-climbable)	As needed	8 years	10 years	As needed
Visual Helicopter Inspection	As needed	Twice a year	Twice a year	Twice a year	Twice a year	Annual
Climbing Inspection	N/A	10 years CMP	N/A	As needed	As needed	N/A
Infrared Helicopter Inspection	Annual	Annual	Annual	Annual	Annual	Annual
Underground Vault Inspections	Every 5 years	1 and 2 year cycles	Annual	N/A	Annual	As needed
Cathodic Protection Inspection	Annual for entire system Every other month for equipment	Annual	Every other month	Annual	N/A	N/A

*Inspection schedules as of Quarter 4 2023.

Table 1-2: Transmission Owner Asset Condition Inspection Cycles – Substations*

Type of Inspection	Transmission Owner					
	Eversource	Avangrid	New England Power	VELCO	Versant Power	Rhode Island Energy
Visual Inspections	Monthly	Every other month plus annual comprehensive	Every other month	Monthly	Monthly	Every other month
Infrared Inspections	Twice a year	Twice a year	Annual	Twice a year	Twice a year	Annual
Transformer Dissolved Gas Analysis	Continuous alarms, with annual sampling	≤ 115-kV = Annual 345-kV = twice a year	69- 115-kV Annual 230 – 345-kV = twice a year	Continuously on some large transformers Manually: Once a year	Annual on < 345-kV Twice a year on 345-kV	Annual
Transformer Offline Inspections	6 or 12 years	LTC transformers are 4-8 years Non-LTC transformers are 12 years	12 years	Every 6 years	Various periods (LTC vs non-LTC)	As needed
Civil-Focused Inspections/ Surveys	6 or 12 years	Every 4 years	As needed	N/A	As needed	As needed

*Inspection schedules as of Quarter 4 2023

1.1 Field Inspections

Field inspections are a key component of the asset monitoring process and represent the first step in determining the condition of transmission system components. The Transmission Owners routinely perform inspections of transmission lines and substations. The common types of asset inspections, which are listed in Tables 1-1 and 1-2, are described in the following sections, by transmission facility component (i.e., overhead transmission lines, underground cables, substations). Before conducting field inspections or other monitoring, Transmission Owner personnel typically review available historical records regarding the asset's performance history.

1.1.1 Overhead Transmission Lines

Each Transmission Owner performs routine inspections of its overhead transmission line assets, which are positioned within dedicated rights-of-way (ROWs). These inspections are conducted using a range of methods; the specific methods used to assess transmission line conditions along a given ROW may vary depending on factors such as terrain and accessibility. The following are typical overhead transmission line inspection methods:

- **Ground Inspection** – manual foot patrols at the groundline of overhead transmission lines to identify material condition issues easily visible from the naked eye or binoculars.

- **Drone Inspection** – manually piloted drones or Unmanned Aerial Vehicles (UAVs) with attached cameras used to inspect overhead assets in detail and get closer to overhead components than can be achieved from ground patrols or a helicopter.

- **Visual Helicopter Inspection** – patrols conducted from a helicopter where the inspector will visually assess the lines from the air, which affords access to portions of the line not visible from the ground. These inspections can vary in speed and detail.

- **Climbing Inspection** – detailed inspections done manually by an inspector physically climbing the structure.

- **Infrared Helicopter Inspection** – inspections conducted from the helicopter using attached Infrared (IR) cameras or equipment to look for "hot spots" on the line.

These inspections cover all components of overhead transmission lines, including the condition of the structures, conductors, cross-arms, insulators, counterpoise, joints, braces, etc. Structure condition issues vary by the type of structure (e.g., wood pole, wood laminate pole, steel pole, lattice tower). For example, wood poles may exhibit evidence of splits, cracks, woodpecker or insect damage, whereas lattice steel towers may have issues regarding rust, bent components, or corrosion, as well as foundation integrity. Age-related degradation is a typical asset condition across all structure types, depending on the year of initial installation and environmental factors.

In general, a variety of factors are considered when performing inspections of and evaluating the components of overhead transmission line assets. The following sections summarize the components of the overhead transmission line assets that are evaluated using these inspection techniques.

When evaluating the asset condition of an overhead transmission line, Transmission Owner inspection personnel inspect for and subsequently report the following types of asset condition issues, such as:

- Broken conductor strands
- Broken or loose tie wire
- Chipped, cracked, or broken insulators
- Leaning poles or structures
- Poles or structures heaved by frost
- Soil erosion around poles, structures, and anchors
- Lightning damage to poles, crossarms, or hardware
- Woodpecker holes in poles (location of holes)
- Significant cracks or splits in wood arms and poles
- Wood rot of arms and poles
- Broken braces
- Visibly crumbling foundations
- Bent members
- Loose hardware, guys, and grounds
- Ground wire staples or nails pulled out
- Broken bonding wire and grounds
- Spacing of or missing ground wire staples or nails
- Rusted guy rods and missing guy guards
- Evidence of gunshot damage
- Conditions of patrol crossings
- Trees that could interfere with conductors
- Conductor clearance over ROW screens
- Soil erosion along the ROW, including along access roads or at permanent work pads
- Change in condition of existing access roads, or new access roads available
- Any observations indicating unauthorized third-party use of the ROW that could interfere with the integrity of the system, such as wood pulp yarding, gravel piles, buildings/dwellings, etc.
- Any potential for environmental concerns, such as wetlands, streams, bird nests, possible lead paint, etc.

The visual inspection is intended to provide information regarding the condition of the overhead line, with suggestions regarding whether any assets must be replaced, can be repaired, or can remain as is.

1.1.1.1. Wood Poles

Wood poles are visually inspected for any defects or deterioration, such as woodpecker or insect damage, rot, splits, cracks, bends or deformation, etc. Any defects or deterioration are typically photographed. In addition, if rot is present, the extent and location is noted.

1.1.1.2. Steel Structures

Steel transmission line structures are evaluated to identify any defects or deterioration, such as bent or deformed members, missing members, visible corrosion, deteriorated paint or galvanizing, broken equipment, etc. Any defects or deterioration are typically photographed, and any evidence of previous structural repairs also are noted. In addition, if corrosion is present, the extent and location is noted; such information is needed to determine if the corrosion is impacting the structural strength (requiring structure replacement) or if it is surface rust with the galvanizing intact.

1.1.1.3. Transmission Line Foundations

Visual inspections are performed of those transmission line structures that are installed on concrete foundations, checking for crumbling concrete, etc. In performing the foundation inspections, the Transmission Owners use standard inspection techniques for in-service concrete (refer to the standards and guidelines in Appendix A).

1.1.1.4. Conductor

The inspections document the conditions of the conductors and conductor attachments, as well as any other observable issues. The analysis of conductor condition is ideally completed by a drone overflight or helicopter, which is useful in identifying the following types of issues:

- Conductor damage (broken or burned conductor).
- Bird-caged conductor (aluminum strand unwinding due to high temperatures).
- Splice points (rusted strands, conductive grease discharge) as the typical life of a conductor splice is 50 years.

1.1.1.5. Equipment and Miscellaneous

Other transmission line components, or equipment supported on transmission lines, also are inspected to identify any loose or missing hardware, cracked or contaminated insulators, lightning damage, etc. Among the components and potential component defects that are typically checked during an inspection are:

- **Cross-arm deterioration**: may be visible as rot or cracking on the cross arm. For example, the depth of decay on a crossarm could be a determining factor if intervention is required or not.
- **Insulator deterioration or defects**: rust, corrosion, chipping, cracking, burns, etc.; signs of contamination, loose connections, misaligned hardware.
- **Hardware**: rust, corrosion, deformation (such as loosening, increase in hole size, etc.).
- **Guy wires**: damaged or deteriorating guy wires, evidence of anchor pull-out, improper attachment, slack guys.
- **Equipment:** any defects or signs of deterioration in equipment supported on the transmission structures (including underbuilt electric distribution lines), as well as their connections and hardware. This could include leaking, rust, signs of overheating, climbing limitations, etc.

1.1.1.6. Grounding

Equipment, cross-arms, and steel structures are typically grounded (NESC Section 09). The visual inspections check for grounding and identify any areas where the ground wire may be missing or damaged. If the wire is missing, it is important to note whether the structure had grounding initially.

1.1.1.7. Environmental and Site Constraints

The on-ground and/or aerial inspections check for any environmental or site constraints that could pose risks to the integrity of the transmission facilities. Typically, the inspections will look for issues such as:

- Existing or potential for tree or vegetation intrusion onto the transmission line conductors, OPGW, or guy wires.
- Accessibility or constructability challenges such as rugged topography, limited existing access, extent of wetlands and watercourses along the ROW or access roads, proximity to developed land use, etc.
- Erosion along the ROW, which could affect structure stability.
- Signs of unauthorized (third-party) construction activity near or in the ROW.
- Encroachments into the ROW.
- Unauthorized attachments to transmission line structures.

1.1.2 Underground Transmission Lines (Cables)

Underground cable systems – which are primarily installed in urban areas where overhead lines cannot be accommodated due to land use development constraints – consist of solid dielectric cross-linked polyethylene (XLPE) cables, as well as pipe type cables (PTC) within which are located HPFF or HPGF transmission lines. PTC systems (HPFF or HPGF) represent older underground transmission technology and involve manholes along the cable route to provide access for maintenance purposes, as well as fluid or gas pressurization equipment at the substations to which the cables connect. Most newer underground lines consist of XLPE systems, which include duct banks encased in a thermal backfill, along with vaults (buried at periodic intervals along the cable route) used for pulling and splicing the cable, as well as for access (via manholes) to the cable system.

All underground cable systems include cathodic protection. HPFF and HPGF cables include various pressure gauges and alarms to detect low pressure, etc. which would indicate a leak in the system, as well as valves to isolate sections of the system in the event of an issue.

The Transmission Owners that operate and maintain underground cables as part of their transmission systems perform the following types of routine inspections:

- **Underground Vault and Manhole Inspections** – visual inspections of underground vaults and manholes to identify physical damage, degradation, water ingress, etc.
- **Cathodic Protection Inspection** – inspection of cathodic protection equipment.
- **Motor Operated Valves and Stop Joints** – these are used to isolate sections of the cable.
- **Fluid or Gas Pumping Facilities** – these pumping facilities and their reservoirs are located at line terminals at the substation.
- **Pressure Detection** – for HPGF and HPFF systems.

1.1.3 Substations

The Transmission Owners operate and maintain substations that range significantly in terms of age, design, and components, as well as overall size and surrounding environmental and land use features. Considerations in the inspection of substation components include operation and maintenance history, age or design factors, power system stress, and equipment obsolescence. The principal types of routine substation inspections include:

- **<u>Visual Inspection</u>** – ground-based visual inspection of substation and substation equipment.
- **<u>Infrared Inspection</u>** – ground-based inspection utilizing IR cameras or equipment to look for "hot spots" in substation equipment, buses, connectors, and lines.
- **<u>Transformer Dissolved Gas Analysis (DGA)</u>** – transformer inspection utilizing oil sampling to identify contaminants in the oil that are used to indicate deterioration of internal components.
- **<u>Transformer Offline Inspection</u>** – detailed inspection of a transformer that requires removing the transformer from service and getting access to the internals, including a review of load-tap changer equipment.
- **<u>Civil Inspection / Survey</u>** – inspection to evaluate geotechnical conditions of the substation and site.

Table 1-3 summarizes the typical asset inspections that are conducted at substations.

Table 1-3: Substation Asset Condition Inspections, by Equipment/Structural Component

Substation Equipment/ Structural Component	Inspection/Monitoring
Foundations	Visually inspect concrete foundations for integrity.
Anchor Bolts	Visually inspect for signs of rust, corrosion, deflection, deterioration, and other defects.
Bus and Supports	Inspect bus work, supporting steel, and terminal structures
Insulators	Inspect for aged brown/blue glass insulators on the main bus structures, which may constitute a risk for a substation outage and thus may need to be replaced.
Reclosers	Inspect for any defects and deterioration.
Switches	Visual inspections of the following: • Examine insulators for cracks, burns, or breaks. • Ensure insulators have been properly cleaned after abnormal conditions such as salt deposits, cement dust, and acid fumes. • Check all contacts for any damage. • Check switch alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction. Any damaged or eroded parts shall be replaced. • Examine switch locks. • If a switch has not been maintained on a periodic basis, the service life may be altered. • A visual inspection when wet, or the use of a temperature scanning detector may indicate hot spots that are possible sources of trouble. • Aged brown or blue insulators used in a switch may need to be replaced.
Surge Arresters	Check for any damage, surface contamination, deterioration of seals and fittings, chips, bending, and alignment issues.
Instrument transformers	Inspect all instrument transformers (CTs, VTs, CVTs, etc.) and wave traps, identifying in particular any areas of deterioration or defect such as leaks and rust/corrosion.
Buildings	Visually assess all substation buildings (control house, GIS, etc.), checking for the following: • Evidence of water infiltration or standing water in the building

Substation Equipment/ Structural Component	Inspection/Monitoring
	• Concrete issues • Corrosion of steel, rust bleeding • Clearance for operational personnel • Room for expandability (empty panels/cubicles) • Physical issues with the building • Means of Egress should be identified during the site visit. • Asbestos panels and remediation • Insulation • Fire rating (primary structural frame) • Combustible materials • Overloaded cable tray (NESC % fill) • Signs of rodent infestation or damage
Grounding	Visually inspect the substation grounding, checking for any locations where a ground appears to be missing.
Lightning Analysis	Review the condition of the substation's lightning protection.
Cable Trench	Visually inspect cable trenches for any signs of damage (such as broken covers) and deterioration. If visible, note fill and available space and any concerns with the entrance into control enclosure/building. Identify any issues with respect to rodents or other animal intrusions.
Battery Equipment	Inspect condition of DC batteries and perform testing as required

1.2 Additional Field Monitoring and Testing

Transmission Owners examine data from additional monitoring sources to comprehensively evaluate an asset's physical condition and overall performance, based on its intended function. These sources may include but are not limited to the following:

- **On-Line Monitoring:** In limited cases, monitoring devices directly connected to assets such as online transformer dissolved gas analyzers may provide daily or continuous asset testing results, which can help determine an asset's current physical condition.
- **Maintenance:** Observations of asset deterioration during routine or unplanned maintenance.
- **Equipment Testing:** Periodic testing of an asset including an asset's performance relative to expected norms.

1.3 Other Factors Considered in Asset Monitoring Analyses

In addition to the asset inspections (including field monitoring and testing), the Transmission Owners also consider other factors when evaluating the overall condition of equipment. These factors include:

Equipment Obsolescence: Although certain transmission system equipment has proven reliable over many years and has no defined asset condition issues, it may no longer be compatible with current technology on a Transmission Owner's system, or may be identified as obsolete due to unavailability of parts or manufacturer support. The Transmission Owners monitor the status of manufacturers of key transmission asset components. Bulletins or notices also may be issued by equipment manufacturers, such as information regarding equipment obsolescence or corporate decisions to discontinue certain types of transmission equipment. A discontinued product poses risks regarding spare part availability and manufacturer support (refer also to "Spare Availability", below).

Asset Failure: The Transmission Owners track the performance of equipment, identifying past issues, and gauge the risk and consequences of future failures, based on such historical information. Failure analyses are important in determining whether an asset problem represents an isolated situation or is indicative of a larger issue that could lead to further failures. In some cases, asset condition projects are designed to pro-actively avert future equipment failure. In other instances, some asset condition projects are required on an unplanned basis, as a result of:

- Problems that are not identified by routine inspections but cause the asset to fail in performing its intended function and require corrective action, but not on an emergency basis.

- An emergency condition that causes a disruption of power or other unplanned loss of an essential transmission asset function, which requires immediate rectification.

Section 2 Initial Evaluation

Overview

As asset inspection data is collected, Transmission Owner personnel review the information, along with other relevant data regarding the asset, such as maintenance history, obsolescence, etc. Data indicating problematic assets is compared to industry standards and guidelines, as well as company policies. The results of these analyses provide an initial evaluation regarding whether or not an asset condition project is required to address the identified issues and the urgency of the project. If so, the Transmission Owner conducts further investigations, proceeding with initial scoping and budgeting for the potential asset condition project.

2.1 Asset Condition Evaluation

The condition of each individual component is the first vital piece of information required to determine the overall asset health. The asset's condition is determined using data collected from the various asset monitoring methods outlined in Section 1, including an asset's age and estimated useful life, physical condition, design compliance, and any obsolescence issues including replacement equipment availability. This determination may include a combination of desktop analyses of the monitoring data and further field assessments.

2.1.1 Age and Estimated Useful Life

Age is an important factor to consider when assessing the condition of an asset; however, age alone is not the sole driver for asset replacement. Any asset placed in service is expected to have a serviceable life, with the prospect that it will reach the end of its useful life after a certain point. The life expectancy of a transmission asset is affected by a variety of factors, such as the initial installation, overall operation and maintenance, and the environmental conditions to which it is subjected.

As a result, the "end of life" point can be driven by many factors, including the asset's age, design, material, environment, vintage, manufacturer, maintenance history, testing results, and other relevant factors. The theoretic "end of life" of an asset can be defined as the point in time when the risk of failures substantially increases, or the cost of ownership is no longer economically feasible.

The average estimated useful life for a given asset type is best estimated based on real world asset failure and maintenance data, as maintained by each of the Transmission Owners. Such information typically includes decades of asset history unique to each Transmission Owner's system, along with available industry data collected through benchmarking efforts in coordination with other utilities. For example, the North American Wood Pole Council provides guidance on the average life span of wood poles. Ontario Hydro performed a study and wrote a white paper on the average useful life of aluminum conductor steel reinforced (ACSR) conductor.

2.1.2 Asset Physical Condition

The assessment of an asset's structural integrity, based on the results of the asset monitoring, is a key driver of decisions regarding the need to repair, replace, or otherwise refurbish the asset. For example, wood pole structures that are characterized by splits, cracks, rot, and insect/woodpecker damage may be at risk of failure to continue to support the existing conductors and shield wire and thus require removal and replacement. Underground HPFF cables that have a history of fluid leaks may be determined to require full or partial replacement to avert future risks of failure and potential environmental impacts.

Environmental and physical factors such as nearby land use development, topography, and weather can affect an asset's operational life. For example, underground cables in urban areas may be subject to damage by third-party utilities, while overhead transmission lines in coastal areas may be affected by extreme weather events (e.g., hurricanes) and salt-spray induced damage.

2.1.3 Design

The Transmission Owners maintain and operate transmission systems comprised of facilities that vary significantly in age, with some installed 100 years ago. Transmission assets are designed and put in service based on industry and Transmission Owner standards and practices at the time of design and installation. However, transmission system design, common industry practice, and company practices have necessarily evolved over time and many standards and codes include legacy clauses. Full compliance with current versions of some standards and codes is typically required only during a major modification or replacement of a facility or component of a facility, though the specific requirements vary by standard or code. Each Transmission Owner must also remain in compliance with current NERC standards and regional standards set by NPCC and ISO-NE.

As a result, updating asset designs to comply with current industry and company standards is an important factor to allow for a more efficient and cost-effective transmission system. As an example, legacy asset designs may not account for modern wind and ice loading requirements, consideration of which is essential to avoiding or minimizing the risk of overhead transmission line failures due to severe climatic events such as Hurricane Irene or Hurricane Sandy.

2.1.4 Obsolete Equipment

As an asset ages, the asset manufacturer may decide to stop supporting and producing the asset or its components. Without support from the manufacturer, the asset may no longer be serviceable and replacement parts will be difficult or impossible to acquire. If such an asset fails, it will be challenging and expensive to repair or replace. Equipment obsolescence may lead to planned replacements over a period of time, possibly as a stand-alone project or in conjunction with other work on the same piece of equipment.

2.1.5 Spare Availability

In the event of a failure, spare component availability is critical to assure prompt asset replacement and thus to maintain system reliability. Spare inventory must be sufficient to replace key assets in case of an unexpected failure. If spare components are not available or a component is no longer manufactured, the Transmission Owners typically identify an asset condition project to pro-actively replace and upgrade the equipment, thereby avoiding the risk of a prolonged failure.

2.2 Asset Performance Evaluation

Assessing the performance and reliability of an asset or an asset model from historical maintenance, inspection and operation history helps measure how an asset has affected system reliability through unplanned outages or forced maintenance. The Transmission Owners routinely evaluate asset performance in making replacement or rehabilitation decisions. Performance factors are considered based on the asset type using current standards and guidelines and include historical data regarding maintenance and inspection, reliability, and operations, as discussed further below.

2.2.1 Maintenance and Inspection History

A review of an asset's maintenance and inspection history is a key indicator of how well an asset was maintained over its life cycle and its maintenance performance. Many factors in an asset's maintenance history, including records of planned vs. unplanned maintenance work and test results, may indicate concerns or risks posed by an asset.

For example, information regarding planned maintenance may indicate that regular, ongoing maintenance is required to keep an asset in service. Records of unplanned maintenance events can indicate the performance of the asset, as well as the effectiveness of planned maintenance processes. An asset that has a high level of unplanned maintenance issues might be an indicator of troublesome equipment or long-term high maintenance trends.

Testing results can indicate end-of-life trends for an asset. These records may indicate future trends of asset reliability risks, maintenance requirements, and ongoing operational costs. These trends can be used to evaluate optimal replacement times and assess risks for continued life in service.

2.2.2 Asset Reliability History

An asset must be able to deliver an expected level of reliability to maintain the effectiveness of an electric transmission system. A history of failure or poor performance of an individual asset or of an asset model, class, component, or manufacturer can assist in determining the status of an asset in relation to its life cycle and in evaluating whether it would be more cost-effective to repair or replace the asset or asset component.

2.2.3 Operational History

Operational history is also a consideration in determining the overall reliability of an asset. In general, the more faults an asset experiences over its lifetime, the more likely it will have performance issues in the future since faults can put the asset under tremendous amounts of electrical and mechanical stress. A review of an asset's operational history can also prove insightful in identifying performance trends that might indicate the underlying cause of the assets' poor performance, which in turn can influence the Transmission Owner's examination of solutions to asset condition issues.

2.2.4 Asset Analytics

Analyses can assist in determining an asset's condition by tracking equipment monitoring data, using predictive models, and collecting metadata to identify and evaluate trends in asset performance and make predictions regarding an asset's remaining useful life.

2.3 Key Impacts and Risks

An asset's deteriorated physical condition and/or poor performance may create impacts that are factored into the initial evaluation. These potential impacts are evaluated comprehensively in conjunction with an asset's condition and performance to properly assess the need for and priority in replacing an asset. Examples of these key factors are shown in Table 2-1.

Table 2-1: Common Factors in Asset Condition Impact Evaluation

Consequences of Deteriorated Asset Condition	Definition / Examples
Asset Cost Increases	Because of asset degradation, the total cost to maintain and operate equipment becomes inefficient
Inability of Legacy Configurations to Perform Adequately or to Modern Standards	Legacy equipment (e.g., power line carrier communication or electromechanical relays, line tapped transformers) may become more difficult to repair or may be contributing to lower reliability performance.
Customer Impacts	Failure or underperformance of the asset may lead to customer outages, negative impacting metrics such as SAIDI, CAIDI, SAIFI, MAIFI (refer to definitions in Acronyms section)
Safety Risks	Continued operation of the asset presents a safety risk
Environmental Resource Impacts	Continued operation of the asset presents an increasing environmental risk
Lack of Operational Flexibility	Outdated assets can affect the ability of the Transmission Owners to operate the electric grid effectively and limit operators' ability to respond to system events

Understanding how an asset's reliability and performance impacts the personnel, surrounding equipment and the power system is an important facet of the initial evaluation.

2.4 System Impacts

Further assessments of impacts on the system can be evaluated to gain a better understanding of risks and benefits that need to be evaluated in making asset condition project decisions. Similar assessments and evaluations to those conducted at an asset level can also be done at a system level. This is necessary for some system level challenges, strategies, and improvement opportunities.

2.4.1 System Reliability and Risk

System reliability evaluations consider the wider system effects of an asset condition project. For example, installing new devices on a transmission line may provide improved reliability metrics for an entire circuit by adding faster response capabilities to the system. System risk evaluations are performed on the system for various challenges that may be identified through system assessments. These risks may be related to legacy system configurations and designs that pose higher safety risks to workers, more risk of human performance errors, or even system resiliency risks. It is important to consider these impacts and potential benefits at a system level as some opportunities and solutions may be overlooked if only performing evaluations at an asset level.

2.4.2 Maintenance Impacts and Challenges

Improvement opportunities that affect maintenance processes and capabilities are important to evaluate. These benefits can have huge impacts by improving the way the system functions or how daily business is performed. This area is measured in terms of maintenance costs, time, and effectiveness. Certain solutions may offer system-wide benefits and improvements to maintenance operations.

2.5 Code Requirements

As part of an asset condition project evaluation, Transmission Owner personnel review the industry and company standards, particularly any that have changed since the asset was installed. A representative list of the standards that are reviewed (and in the final design of an asset condition project) are provided in Appendix A.

2.6 Substation Considerations

The initial evaluation of substation asset conditions uses as input the results of the visual on-site inspections and monitoring (refer to Section 1), as well as the factors described in Sections 2.1 through 2.5. In addition, the following additional factors are often considered in substation asset condition evaluations.

2.6.1 Circuit breakers

Defects and deterioration identified during inspections along with known performance issues with the particular models are all considered when assessing the condition of circuit breakers. In some cases, only certain components (e.g. bushings) may in poor condition and may be replaced. In other cases, complete replacement of the breaker will be required. Offline testing can also be used to indicate potential problems with internal components.

2.6.2 Power Transformers

Oil testing results are frequently used as an indicator of a need to conduct a further screening of a power transformer. Many times, a visual inspection identifies defects and deterioration, such as leaks, corrosion, rust, connection issues, evidence of failure (burns), or other physical damage that might have occurred since the most recent formal condition assessment. The transformer loading also is evaluated and any criteria violations noted.

2.6.3 Electromechanical Relays

Electromechanical relays are typically over 50 years old and are no longer supported by manufacturers. There is also a decreasing number of technicians who are able to repair or replace them. Moreover, modern microprocessor-based relays have numerous advantages over their electromechanical predecessors, including programmability (which reduces wiring and allows for several functions to be served by a single relay), use of modern communication-based protection methods (including fiber optics), advanced self-testing and alarming functions, storage of fault records and the ability to remotely access records and alarm information. As such, replacement and upgrade to microprocessor-based relays should be considered, especially if in coordination with another project. A visual inspection of the relays is typically performed, checking for any corrosion, rust, signs of burning, discoloration, deterioration, dirt, dust, leaking, cracking, peeling, or pitting. Relays are also tested periodically to ensure performance in-line with predetermined testing standards.

2.6.4 Control Houses and Enclosures

Control house projects can be driven by a variety and combination of needs. The asset condition of the control house itself is a sometimes a consideration. Additional drivers such as fire safety and clean air monitoring considerations, the need to house additional or larger equipment (such as larger battery banks or backup battery banks), the need to provide improved reliability through wiring separation and other means and the need to meet regulatory obligations such as physical security protection may also determine the need for control house projects.

2.7 Transmission Line Considerations

During the evaluation of the visual inspections described in the above section it should be determined using the criteria contained in this document if the asset reviewed requires replacement, can be repaired, or remain as is. If it is determined that a transmission line project is required, the potential long term implementation times for certain transmission line projects should be considered to ensure the asset in question can maintain reliable service until its eventual replacement.

Additional line reports from the Transmission Owner’s operations, maintenance, and asset condition groups should also be reviewed, as their inspections may have additional tests completed (such as sounding of poles, excavation for ground line inspection, and climbing for cross arm inspection).

Transmission line assets are modeled (using PLS-CADD or other means) to evaluate the potential impact of replacing an asset across an entire transmission line or right-of-way (ROW), taking into consideration factors such as terrain, sag, tension, clearances, and loading. Depending on the results of the modeling, modifications to surrounding assets to support the successful replacement of a deteriorated asset may need to be evaluated.

2.8 Asset Health Indicators

The Transmission Owners use asset health indicators for some asset types to help inform asset condition evaluations. Each Transmission Owner applies different asset grading methods, but all are consistent with good utility practice. Some Transmission Owners have developed asset health scoring approaches to rank certain asset types. Appendix C describes uniform grades used by all Transmission Owners for PAC presentations that involve transmission line structure replacements. Uniform grading of other transmission and/or substation elements for presentation purposes is being assessed for future inclusion in additional appendices. These asset health scores are used as part of the screening assessment (see Section 2.6) of the initial evaluation work, but may not provide a complete picture of the health of an asset. As such, they are only part of the decision-making process for determining whether to proceed with an asset condition project. Common indicators are summarized below and are derived from data gathered during Asset Monitoring as described in Section 1.

Circuit breaker condition indicators typically including, but not limited to, asset age, environmental impacts, short circuit margin, operational integrity (operating location in substation and frequency of operation), general model obsolescence (ability to obtain trained service personnel and replacement parts), and field assessment data (maintenance notifications/issues for breaker components like bushings, mechanism, contacts, dielectric media). Operational issues also are considered in the breaker evaluation.

Power transformer condition indicators typically include several parameters, such as oil quality, dissolved gas analysis, electrical testing, loading, age, information collected from inspections, and number of repair notifications.

Transmission line asset condition indicators include such information as current and historical field inspection data, obsolescence issues, and known problems with particular manufacturers, models or vintages of equipment. For transmission line structure condition, each TO has developed a grading system to rate the condition of structures based on visual inspections. These grading systems are described in Appendix C, including a uniform grading system to be used in PAC presentations.

Control house asset condition indicators include a myriad of asset condition considerations varying from the physical roof, walls, and foundation, to the condition of the various types of equipment contained within the structure.

2.9 Initial Evaluation Results

Based on the evaluation of the asset monitoring results and the various other factors described in this section, the Transmission Owner determines whether the identified asset condition issues warrant further examination to refine potential risks and to establish an initial scope for a potential asset condition project that needs to be developed in the near-term.

If so, the Transmission Owner proceeds with additional steps to determine the initial scope, cost, alternatives, and schedule for the project. Importantly, the decision at this point is simply whether the solution is likely to be an asset condition project.

Major decisions about the project scope, cost, and schedule are made in future steps, based on the additional detailed information compiled regarding the project and based on the criteria described in those steps.

If, based on additional information developed as part on the decision-making process, it becomes clear that an asset condition project is not necessary and the identified asset condition issues can be resolved through other means such as minor maintenance, then the Transmission Owner will proceed with the maintenance in lieu of a larger asset condition project.

Section 3 Initial Scoping

Overview

The purpose of the initial scoping phase is to integrate the information collected during the asset monitoring phase (Section 1) and the needs identified in the initial evaluation (Section 2) to develop initial solution concepts which will include a solution "Base Alternative" that addresses known asset condition needs in the most targeted manner possible, and potentially additional solutions that could address the immediate and future needs more efficiently. The initial solution concepts allow a preliminary project budget and schedule to be established to support additional design and evaluation during the Holistic Evaluation step (Section 4). Once a project budget is established, the Transmission Owner will track the costs associated with the project and utilize internal controls to ensure that project costs are managed within the established budget.

For many projects, the preliminary project budget is sufficient to support the completion of initial scoping and holistic evaluation, leading to the recommendation of a preferred solution alternative. However, more complex projects may require higher development budgets to complete the holistic evaluation phase. For these projects, additional interim milestones and budget approvals may be used to manage project development costs. For example, a project that is expected to incur $2 million in development costs could be approved with an initial budget of $500,000 and subject to periodic review in order to obtain increased funding. These interim milestones and thresholds for periodic review are established on a case-by-case basis.

3.1 Initial Objective

The first objective of any asset condition project is to resolve the identified asset need in order to maintain the reliability of the transmission system. During the initial scoping phase, the objective is to define a solution concept that addresses the known asset condition issues.

In most cases, the scope of this solution concept will consist primarily of replacing the transmission asset components that have known asset condition issues. The purpose of defining a solution concept at this stage is not to predetermine the final solution, but rather to allow the development of a realistic project schedule and budget based on the *likely* final solution. The Base Alternative will always be considered and presented both to the Transmission Owner's management and to the PAC, but consideration of additional factors may lead to a different solution ultimately being selected as the preferred solution during the Holistic Evaluation phase. The following summarize the typical factors considered in developing an initial solution concept for overhead transmission line, underground transmission line, and substation asset condition issues.

Typical initial solution development considerations for an overhead transmission line

- Is the number of deficient structures large enough that a project to replace them will likely require construction along most (or all) of the ROW?
- Are a large number of structures on the line beyond their life expectancy and should be evaluated for proactive replacement due to construction efficiencies?
- Are there known issues or risks with the conductor type based on inspection or failure history?

- Are there known issues with the shield wire based on inspection or failure history?
- Is there a need for improvement in system protection and monitoring?
- Are there known issues with the insulators based on inspection or failure history?
- Are there concerns with obsolescence and ability to obtain replacement parts?

If an overhead transmission line is found to have limited asset condition issues, the initial solution concept will typically be targeted repairs to address those specific issues (i.e. the Base Alternative or a version thereof with minor scope additions). A targeted repair could include replacing only damaged or degrading hardware or structure components (such as crossarms) or complete replacement of affected structures. However, if the asset condition analyses reveal more widespread issues along the transmission line, a full or partial line rebuild may be appropriately considered as the initial solution concept.

Typical initial solution development considerations for an underground transmission line

- Is there a history of faults or leaks?
- Are there known issues with the conductor based on inspection or failure history on other lines?
- Known issue from vault inspections?
- Are there concerns with obsolescence, manufacturers, and ability to obtain replacement parts?

If an underground transmission line has multiple known issues, the initial solution concept may be a full line rebuild or targeted repairs (such as reconductoring), depending on the type of issues and technology in use.

Typical initial solution development considerations for substation equipment

- Are deficiencies widespread within the substation and not limited to particular pieces of equipment?
- Is deficient equipment located within the substation control house and, if so, does the control house have sufficient space to accommodate replacement of the equipment?
- Will replacing or repairing the equipment in-place present significant constructability challenges?
- Is the substation location suboptimal? For example, is it in a flood-prone location?
- Are there concerns with obsolescence and ability to obtain replacement parts?
- Does the substation comply with NPCC criteria and other relevant standards and regulations?

If asset condition issues are widespread within the substation, the initial solution concept will typically be a more holistic project that encompasses the potential replacement of a variety of substation equipment. If the issues appear limited to a subset of substation equipment, the initial solution concept will typically be the Base Alternative.

3.2 Transmission Owner Internal Review

Depending on the expected complexity and cost of further developing the design for a project, key Transmission Owner management may be tasked to review the asset condition project at this initial stage. For example, the level of design necessary to complete the assessment of a potential full rebuild of a transmission line is more complex than the level of design needed for simply replacing transmission line structures and may require additional levels of management review. This process ensures that a full range of appropriate factors, including cost effectiveness and system reliability, are considered when determining the need for an asset condition project.

Examples of items that may be discussed during the internal corporate review include:

- Will the scope address the identified asset condition issues?
- Have lessons learned from previous projects been incorporated into the scope(s)?
- Will standard equipment be used?
- What is the need date for project completion?

After the Transmission Owner management review determines the need for the project, funds are allocated to further study and refine the initial scope of work.

3.3 Addition to Transmission Owner Asset Condition Project Forecast

A project will typically be added to the Asset Condition Project Forecast file at this stage. The Asset Condition Project Forecast is published annually by the Transmission Owners to provide stakeholders with a preview of anticipated asset condition projects over a 5+ year time horizon.[4] A project will typically be presented to PAC after a more holistic analysis is complete. The process for requesting and addressing stakeholder feedback is described in Section 5.

3.4 Project Team

After Transmission Owner management approves funding to further study the project, a project team is assigned, consisting of a project manager and representatives of involved company departments. The project manager and team establish an initial project milestone schedule and tasks are assigned to move the project forward to the next step in the process, identifying specific tasks, including environmental field studies and constructability reviews, performing stakeholder outreach, etc.

The team includes representatives from various Transmission Owner departments (depending on the type of asset condition projects). The members of the team may have knowledge and expertise in disciplines such as:

- Protection & Controls
- Transmission Planning
- Asset Management
- Real Estate
- Line Engineering

[4] See https://www.iso-ne.com/static-assets/documents/100014/august_2024_ac_project_forecast.xlsx for a copy of the forecast provided to stakeholders in August 2024.

- Condition Assessment
- Construction
- Substation Engineering
- Siting
- Operation & Maintenance
- Distribution Planning
- Environment & Permitting
- Project Management
- Procurement/Purchasing

Section 4 Holistic Evaluation

Overview

The Holistic Evaluation stage is the point in the planning process wherein preliminary solutions identified during initial scoping are subject to the comparative analyses described in this section. The goal of the Holistic Evaluation is simple: to identify preliminary preferred and alternative solutions that satisfy the identified asset condition needs, and potentially other identified or anticipated needs, most efficiently and cost-effectively. The process, however, is not simple as there are a variety of factors that must be considered that will vary by project. While sequentially this stage is shown as occurring in between Initial Scoping and Project Selection, some of the analysis used in the holistic evaluation is conducted during Initial Scoping as part of the initial identification of potential solutions.

The alternatives developed during the Holistic Evaluation will be presented to a Transmission Owner leadership team for selection and approval of a full budget and cost estimate for the project. This information will also allow for a comprehensive presentation of the proposed solution and alternatives to stakeholders and states at the ISO-NE PAC for feedback.

4.1 Approach to Holistic Evaluation

The holistic evaluation is an in-depth analysis that includes review of both qualitative and quantitative information, typically for multiple solution alternatives. The holistic evaluation will consider a Base Alternative identified during initial scoping that addresses only the immediate asset condition needs in the most targeted manner possible, and in most cases will also consider more comprehensive solution alternatives that address additional less-immediate known issues and anticipated future needs in an efficient and cost-effective manner.

The goal of the holistic evaluation is to identify the most efficient and cost-effective solution that considers not only the immediate needs, but also opportunities to address other needs when practical and feasible. The overarching objective is to minimize adverse effects on the system, environment, customers, and communities while maintaining cost-effectiveness. Qualitative and/or quantitative evaluations, including cost-benefit analysis, may be performed to assess multiple viable, cost-effective alternatives, including as required by regulatory processes. This process is necessarily iterative as there may be criteria for selection of the preferred alternative that conflict with each other. For example, the initial capital cost for a solution is a critical criterion for decision-making, but the solution with the lowest up front capital cost may be disadvantageous from a constructability or environmental perspective or may fail to take advantage of a broader scope that has a lower long-run lifecycle cost for customers.

Under some situations, the factors considered during the Holistic Evaluation phase may be simplified. For example, an asset condition issue that poses a significant risk to the public and/or to the reliability of the transmission system (e.g., an overhead transmission structure destabilized by third-party damage; failure of key equipment at a substation) will require a pro-active and immediate solution. Similarly, for some projects, typically those where the Base Alternative involves a straightforward direct replacement of a particular transmission component, a single cost-effective solution may be optimal if there is no larger alternative that is anticipated to have a lower life-cycle cost, better performance, or otherwise address a combination of asset condition needs in a more cost-effective manner. In such a case, an extensive comparative analysis of solution alternatives is unnecessary and a solution can be selected simply on the basis of viability and lowest overall cost.

4.2 Tasks Performed During Holistic Evaluation

In performing the holistic evaluation of a potential asset condition project, the Transmission Owner thoroughly assesses all relevant information and factors affecting potential solutions, with a goal of advancing the most efficient solution, as cost-effectively as possible, while minimizing environmental and community impacts. The following primary tasks are typically performed during this stage of an asset condition project planning.

Conceptual Engineering and Cost Estimating

- Initial selection of replacement equipment/materials and the location for installation
- Development of formal cost estimates

Conceptual Constructability Review

- Initial review of construction considerations, including access road and work pad locations, permitting requirements, whether additional ROW width will be required, etc. This effort typically involves input from the multi-disciplinary project team and may include initial project walkdowns, mapping, environmental evaluations, and constructability reviews, as well as the initial identification of project challenges and impact minimization goals.

Project Efficiency Analysis

- Potential for coordination with other projects
- Opportunities to address additional scope/needs that may trigger alternatives with potential scope enhancement and/or engineering design modifications
- Examine line resiliency (e.g., ability to withstand severe regional climatic events)

4.3 Key Evaluation Criteria and Other Criteria Considered

In performing the holistic evaluation of a potential asset condition project, the Transmission Owners consider a variety of criteria in determining the preferred alternative solution. These criteria are summarized in Table 4-1. This table distinguishes between “Key Evaluation Criteria,” which commonly show distinctions between solution alternatives for typical asset condition projects and “Other Evaluation Criteria,” which are also evaluated for asset condition projects when necessary but less frequently show distinction between solution alternatives.

Table 4-1: Representative Types of Information Considered in the Holistic Evaluation Process

Information	Description
Key Evaluation Criteria *(Commonly affect solution selection for asset condition projects)*	
Asset Condition Need and Criticality	• Asset criticality and health assessments as described in Section 2 of this document are included in solutions to ensure that the selected solution addressed all identified critical asset condition needs. • Asset age is a key factor but is not determinative on its own.
Project Costs	• Initial cost estimates for potential solutions are developed for use in holistic evaluation. • The project team assesses the anticipated lifecycle costs of alternatives, including but not limited to, the avoided future cost of solving multiple needs with one project as opposed to solely solving the immediate need. • This criterion is critical for achieving the selection of a solution that minimizes costs to customers over time.
Constructability	• Relative difficulty of constructing different alternatives • Availability of land resources is considered, particularly when potential solutions require additional ROW (easements) or property acquisition
Siting, Environmental Permitting, and Other Regulatory Requirements	• Laws, regulations, and procedures regarding environmental, siting, and other regulatory permitting requirements, and the relative challenges of these requirements for potential solutions are considered. • Avoid, minimize, or mitigate adverse impacts to local ecosystems, including wildlife and habitats. • Comply with state and federal environmental regulations; ability to implement environmental best management practices to avoid or minimize adverse effects to environmental and cultural resources. Representative examples of best management practices and mitigation include but are not limited to: ✓ Pre-construction studies aimed at identifying and providing options for avoiding sensitive resource areas. ✓ Use of targeted environmental controls, specific to the asset condition project area, e.g., wetland matting, soil erosion and sediment controls. ✓ Engineered solutions to minimize or avoid sensitive areas. ✓ Include opportunity work to make cost-effective use of environmental controls by addressing all potential needs in a location or ROW, thereby alleviating the need to revisit the same location in the near term. • Consider carbon footprint and adherence to regulatory and company greenhouse emissions goals. • Avoid, minimize, or mitigate impacts to cultural resources.
	•
Other Criteria *(May affect solution selection for asset condition projects in some cases)*	
Community Concerns	• Known community concerns identified through outreach or past experience are considered, including considerations of potential project impacts on vulnerable or marginalized communities (environmental justice/equity considerations,

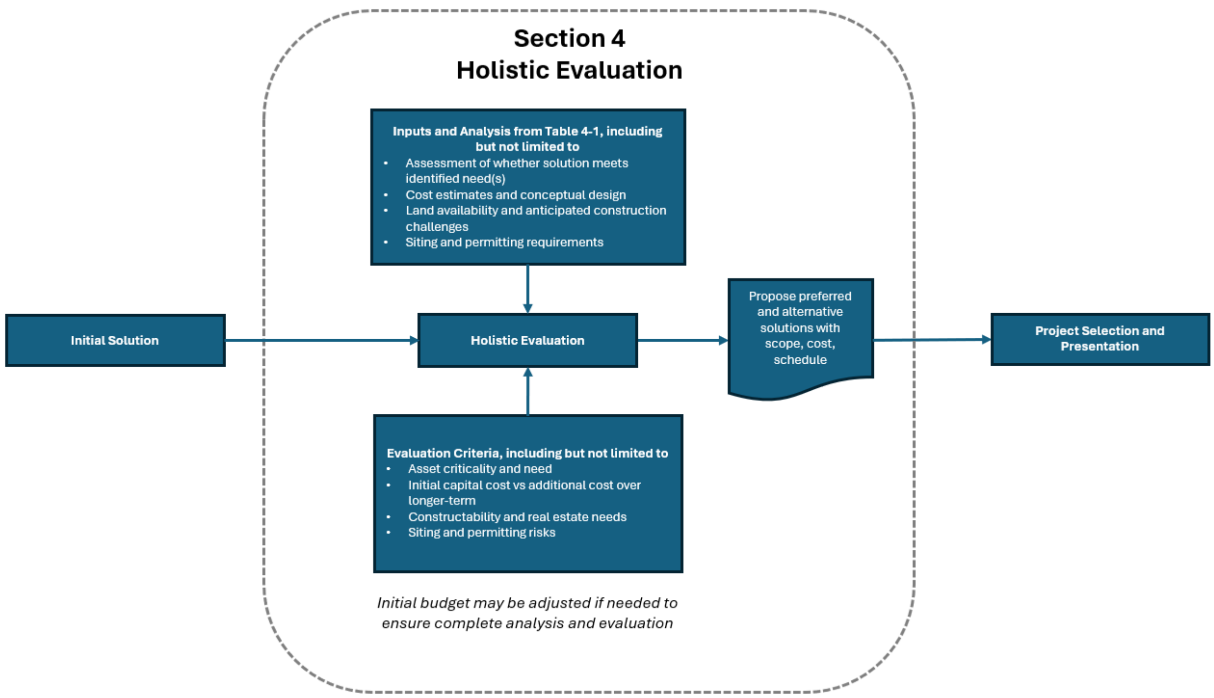
Information	Description
	though the specific regulations and approaches to incorporating these considerations vary by state). • Costs associated with engineering design choices and construction methods that exceed current engineering and design practices in the area in which a potential project will be constructed are identified as part of the submission of a Transmission Cost Allocation (TCA) Application to ISO-NE and the NEPOOL Reliability Committee and may be reviewed for potential Localized Costs by ISO-NE and the Reliability Committee under Schedule 12C to the Open Access Transmission Tariff.
Technology and Resources (Including Real Estate)	• Technologies available for effectuating a solution are considered, including assessment of new and emerging transmission technologies. • The availability of required resources to engineer, develop and execute a project, including both human resources as well as construction equipment and material, are considered.
Codes and Standards	• Applicable codes and standards requirements (e.g., see Appendix A) are always considered and adhered to in the design of potential solutions.
Safety and Security	• Use modern equipment to comply with current safety codes. • Compliance with security regulations and use of best security practices for assurance of robust protection of critical assets.
Route / Site Analyses	• Identify route options and provide a rationale for identifying the preferred project route or site selection.
Other Utilities	• Consider the effect of potential solutions on water, gas, communication, transportation, and other infrastructure.
Equipment Selection and Coordination with Other Projects	• Other project work that may affect or be affected by the asset condition work is considered when scoping potential solutions. • Evaluate alternatives, as applicable, to address risks of potential future environmental impacts (e.g., flooding, extreme weather). • Consider adaptable, flexible solutions to accommodate future technologies or the installation of future equipment. • Opportunities to address related asset condition needs through combined or coordinated projects when doing so is more cost-efficient are considered for potential solutions. • Additional system capacity may be created as an incidental benefit of installing new equipment, but creating incremental capacity is not the primary driver of asset condition projects
Schedule	• Assess the ability to execute multiple needs together on the same timescale. • Consider regulatory or Transmission Owner in-service deadlines.
Outage Coordination and Customer Risk	• Coordination with other ongoing or future work on a Transmission Owner’s system. • Coordination with adjacent utilities and customers. • Availability of required power system equipment outages to support construction. • Minimize risks (during project construction) to system reliability and customer service. Customer impacts are typically assessed by, but not limited to, the number of customers and criticality of customers (e.g., hospitals, schools, municipal buildings). • The ability or availability to perform work energized vs de-energized.

4.4 Results of Holistic Evaluation

After the compiling the analytical information (as identified generally in Table 4-1), the Transmission Owner's personnel perform a comparative analysis of the solution alternatives, including the Base Alternative, that would resolve the initial asset condition need identified in Section 2. Such information typically includes a review of the need (with photographs of asset condition issues), high-level mapping, a review of the project scope, conceptual engineering, benefits, costs, and anticipated schedule. The comparative analysis considers both the costs and benefits of different solution alternatives, both quantitative and qualitative, and considers the criteria shown in Table 4-1 that are relevant to the particular project. The cost analysis between alternatives considers the long-term cost impact on customers of each alternative and not just the initial capital cost.

The output from the holistic evaluation process consists of preliminary preferred and alternative solutions that are presented to the Transmission Owner's leadership for decision making. Figure 4-1 illustrates the criteria typically considered in the holistic evaluation process, including, "Key Evaluation Criteria" as shown in Table 4-1 which frequently affect decision-making between different project alternatives and "other criteria" which are typically evaluated but may be less critical to decision-making.

Figure 4-1: Process Flow Diagram of the Holistic Evaluation Process



Section 5 Project Selection and Presentation

Overview

After the completion of the holistic evaluation, the Transmission Owner proceeds with its internal approval process to obtain management endorsement of the proposed solution and associated schedule and budget. The project and evaluated alternatives are also presented to the PAC and any feedback received is addressed by the Transmission Owner.

5.1 Management Review and Selection of Preferred Alternative

The results of the holistic evaluation, including the Base Alternative and other analyzed alternatives, are presented to company management for review and selection of the preferred alternative, which may differ from the alternative presented by the project team. While the details of Each Transmission Owner's management approval processes vary, there is commonality in that each Transmission Owner's management approval process requires approvals at increasingly senior levels of their organizations depending on the project's complexity and financial impact.

The preferred alternative for an asset condition project is typically selected by Transmission Owner management based on a review of the information developed (including any alternatives) in earlier steps, including the evaluation criteria listed in Table 4-1.

While the level of importance of a particular factor will vary depending on the asset condition need and the proposed solution, the following factors, identified as "Key Evaluation Criteria" in Table 4-1, are key considerations for most asset condition projects:

- Asset criticality and ensuring that a project fully addresses the identified needs
- Cost, including striking an appropriate balance between upfront capital cost and additional costs over the longer-term
- Constructability of the proposed solution and real estate needs
- Siting and environmental permitting requirements

The decision-making process includes a quantitative and qualitative comparison between the Base Alternative and other alternatives, including an assessment of the benefits and costs of each alternative evaluated.

The approval process is often iterative and, before a decision is made, may involve the development of additional information, investigation of different solutions alternatives, the performance of further analyses, or refinements to cost estimates. After the Transmission Owner management is satisfied that sufficient information is provided about the asset condition issue and alternative solutions, the leadership will select the Transmission Owner's preferred alternative, taking into consideration all costs and benefits presented.

5.2 Regional Stakeholder Presentation and Review at the PAC

Under the ISO-NE OATT, Planning Procedures, and Transmission Planning Process Guide, proposed PTF asset condition projects with expected costs greater than or equal to $5 million must be presented to regional stakeholder committees. These committees include the ISO-NE PAC (described in this section), and NEPOOL RC (described in Section 5.4, below).

First, as detailed in Section 6.3 of the ISO-NE Transmission Planning Process Guide,[5] proposed PTF asset condition projects must be presented to the ISO-NE PAC before the project can be added to the ISO-NE Asset Condition List. The PAC is an open and public forum for stakeholders to provide feedback and input to ISO-NE and the Transmission Owners on the regional PTF system planning process, including future asset condition projects. Participants in the PAC are able to ask questions of the Transmission Owner sponsoring a project, both during the meeting and in writing.

While Transmission Owner's presentation of an asset condition project to the PAC may occur at any point during a project's development, providing that the minimum requirements of the Transmission Planning Process Guide (TPPG) are met, the Transmission Owners typically present projects to PAC shortly after obtaining internal approvals of the preferred alternative and associated cost estimate, as described in Section 5.1. This allows stakeholders to review the full analysis supporting a proposed project, including estimated costs and evaluation of alternatives, while still allowing for modifications to be made to the project based on stakeholder feedback.

Appendix D to this Guide, "Stakeholder Review Process for Asset Condition Projects," sets forth the Transmission Owners' timing for stakeholder presentations, the process and timing for stakeholder feedback and questions, and Transmission Owner responses. Appendix E to this Guide, "PAC Presentation Content Guidelines," summarizes minimum content for asset condition project presentations to the PAC. Appendices D and E will be reviewed periodically and may be updated to reflect the needs of the stakeholder process for asset condition project review.

5.3 Consideration of External Feedback

As described above, Transmission Owners will respond to written feedback from PAC in writing, either in a memo, by making follow-up presentations to the PAC, or both.

Transmissions Owners use stakeholder feedback to validate the selection of a preferred solution or to modify the preferred solution, or proceed with an alternative solution, depending on the nature of the feedback received. If a project is modified or an alternative solution is selected, based on feedback from the PAC, the Transmission Owner would make a follow-up presentation to the PAC to explain the changes and provide an updated cost estimate.

[5] https://www.iso-ne.com/static-assets/documents/2023/09/2023_09_08_pac_transmission_planning_process_guide.pdf

5.4 Additional Regional Stakeholder Presentation and Reporting Requirements

After a project is presented to the PAC, it is added to the ISO-NE Asset Condition List on the ISO-NE website. The Asset Condition List tracks project cost estimates and projected in-service dates and is updated three times per year. Under the TPPG, a project must be re-presented to the PAC if the cost estimate increases by more than 50% and is incrementally more than a $5M increase relative to the last estimate provided to the PAC or if the scope of the project is changed significantly from the original PAC presentation.

Prior to the start of major construction, a Transmission Owner developing a PTF asset condition project with expected costs greater than or equal to $5 million must submit a Transmission Cost Allocation (TCA) application to ISO-NE. The requirements for the timing and content of TCA applications are described in more detail in ISO-NE Planning Procedure 4. In particular, the Transmission Owner must present the TCA application to the NEPOOL RC, with multiple discussions required for larger TCA applications. The NEPOOL RC votes on whether to recommend that the project be approved for regional cost allocation by ISO-NE.

Section 6 Project Design, Siting/Permitting, and Preparation for Construction

Overview

After the Transmission Owner authorizes fully funding the asset condition project (Section 5), the multi-disciplinary project team, led by a project manager, proceeds to refine the project planning and design. This includes performing additional engineering and constructability reviews, conducting environmental field studies, proceeding with the materials procurement process, preparing/submitting applications for required permits and siting approvals, and finalizing a project schedule.

Significant changes to the project scope or cost that occur during project design (or project execution) will typically require a re-approval of the project via the processes described in Section 5, including additional presentations to the stakeholder committees.

6.1 Project Management and Project Team

During the design phase, the project manager supervises a multi-disciplinary team that is responsible for refining the project design, procuring project materials, completing engineering analyses and constructability reviews, performing environmental studies, compiling permit and siting applications, and initiating outreach to municipal and other stakeholders and abutters. The project team is comprised of representatives from different departments within the Transmission Owner, supplemented by specialized consultants.

Representatives from a Transmission Owner’s scheduling, cost management, and outage groups also may be assigned to the project team. In addition, depending on the project, specialized consultants may be retained to assist the team, such as for detailed engineering and site-specific environmental studies.

The project manager is responsible for supervising the team, with the overarching objective of providing a final project design and obtaining all required permits and other regulatory approvals so that the project can proceed to the execution phase. The project manager schedules regular project team meetings, reviews project materials, and maintains communication with the Transmission Owner leadership regarding the status of the project design. Typically, a Transmission Owner asset condition representative continues to be a part of the team.

Among the project manager’s responsibilities are typically the following:

- **Scheduling**: ensure that the project team has the resources necessary to complete the project design as planned, as well as to execute the project in accordance with the in-service date defined in the project development phase.

- **Cost forecasting**: as the project design phase proceeds and more detailed input is received regarding the project (e.g., results of environmental studies, constructability reviews, permitting timelines), track project cost estimates (by category) to verify that tasks are on budget or to pro-actively identify and address potential cost issues.

- **<u>Risk assessment</u>**: identify potential risks to the completion of the project as planned, including severe weather delays, timelines for permitting, or unknown subsurface conditions (e.g., rock) that could limit construction progress.

- **<u>Cost control management:</u>** Complying with Transmission Owner processes to track and pro-actively manage costs in accordance with specified budgets.

Based on the team's detailed evaluations, modifications to the project definition as presented to the Transmission Owner project leadership may be identified. Depending on the extent of the modifications and the project cost and schedule implications, the project manager and asset condition group may provide the project changes to the Transmission Owner leadership for review and approval.

6.2 Project Team: Typical Multi-Disciplinary Tasks and Activities

The multidisciplinary project team is typically comprised of representatives from various departments within each Transmission Owner's organization. Department representatives are usually dedicated to the project team for the life of the project, and report to the project manager.

The department representatives, coordinating with the project manager, also may request the assistance of specialized consultants to complete certain tasks that cannot otherwise be performed by the Transmission Owner within the scheduled timeframe. The project manager and department representative are responsible for determining the need for specialized consultants, obtaining a scope of work and cost estimate from the consultants (or multiple consultants if the work requires a competitive bid), and for managing the consultant's work throughout the project design and, as appropriate, execution processes.

6.2.1 Typical Project Team Tasks, by Discipline

Typical tasks performed by the multidisciplinary team (which may vary based on project-specific requirements) include:

- **<u>Engineering</u>**: Refine engineering designs and provide engineering drawings as required to support project siting, permitting, and ultimately construction. The engineering team will also review all relevant standards, as outlined in the appendix. The engineers assigned to a project also will typically coordinate analyses of a project's potential effect on electric and magnetic fields (EMF) and evaluations as to whether communication with the Federal Aviation Administration (FAA) is required (depending on whether a project involves changes in overhead transmission line structure height). See Appendix B for a list of design standards considered in this process.

- **<u>Construction</u>**: Construction representatives assigned to the project conduct constructability walkdowns of the project site, typically along with the project manager and other team representatives, to identify potential construction issues based on the characteristics of the site (e.g., terrain, environmental resources, accessibility) and then work with the team to finalize the project design to minimize or avoid such issues.

- **Environmental**: Both desktop and field studies are required to fully characterize the environmental resources in a project area so that the project can be designed to avoid or minimize adverse environmental impacts. The results of environmental analyses must be incorporated into the Transmission Owner's submissions to various regulatory and siting agencies.

  The environmental analyses required depend on the type and location of a project. In general, environmental resource specialists assigned to a project will conduct analyses of topography, geology, soils, water resources (wetlands, watercourse, other water bodies), vernal pools, vegetation and wildlife, land uses, visual resources, cultural resources, and transportation. The environmental studies also will entail consultations with various involved regulatory agencies, including federal agencies such as the U.S. Fish and Wildlife Service and U.S. Army Corps of Engineers, as well as state agencies such as environmental protection departments and State Historic Preservation Offices, among others. The environmental representative on the project team is usually responsible for coordinating with the project manager to submit environmental permit applications to involved federal, state, and (as applicable) local regulatory agencies.

- **Siting:** The siting representative on the project team is responsible for preparing – in coordination with the rest of the project team - any submissions to state agencies that have jurisdiction over transmission projects. A project siting application typically incorporates the detailed information prepared by others on the project team, including data regarding the project need, alternatives considered (as applicable), construction methods and schedule, engineering design, environmental resources and impact mitigation measures, EMF analyses, FAA analyses, and project outreach.

- **Outreach:** The Transmission Owners adopt various pro-active approaches to inform municipalities, agencies, interested stakeholders, and abutters (landowners, renters) about a planned project and to establish an effective communications program that continues throughout the project execution process. Some outreach approaches are driven by different state agency requirements concerning abutter notifications. In general, the Transmission Owners' project outreach efforts involve consultations with municipal and state agency representatives, project websites, letters describing the project that are distributed to affected abutters, and individual meetings with abutters or other stakeholders, among others. Copies of certain outreach materials also may be provided as part of siting or regulatory submissions, if required. Feedback at this stage is typically addressed via meetings with the affected individuals and organizations, or via state siting or regulatory processes if the feedback is provided through such a process. In most cases, feedback can be addressed with minor changes to project designs or construction plans without any impact to the project budget.

- **Outage Planning**: Asset condition projects necessarily involve coordinating work to maintain service to customers and minimize overall outages. Further, safety is a key consideration during any project work near live transmission lines. The outage planning effort is designed to:

- ✓ Minimize disruption, and outages required for the safe construction of the project in coordination with any other planned outages.
- ✓ Inform multiple departments well ahead of a planned outage.
- ✓ Plan the construction schedule around the outage to assure worker safety.

- **Materials Procurement**: The procurement department is responsible for identifying the cost and lead time for the various materials needed for the project.

6.3 Final Pre-Construction Plans

During final pre-construction planning, the project team completes all steps necessary to proceed to the start of project construction, including the issuance of construction documents that reflect adherence to permits and approvals received from regulatory and siting agencies. The steps that are typically completed during this phase include, but may not be limited to the following:

- Complete detailed engineering design documents – that is - Issued for Construction (IFC) drawings, including (as appropriate) cross-sections, plan and profile drawings, and site plans.

- Acquire all required permits and approvals from regulatory and siting agencies. Final agency approvals may reflect the project as submitted by the Transmission Owner or may include conditions that dictate project modifications, such as scheduling to avoid construction during critical periods in a species' lifecycle, realignment of project elements (e.g., moving a structure replacement location to avoid a wetland), modification of construction work hours to avoid noise impacts to a sensitive receptor, etc. Agency approvals also may specify that the Transmission Owner provide periodic reports during project construction, such as to document regulatory compliance or to report construction progress, as well as require that the Transmission Owner seek approval for any significant modifications to the project plans or an extension to the project schedule.

- Complete detailed, final mapping, consisting of aerial-based maps that depict project work areas and access roads, and reflect any modifications that must be incorporated to comply with regulatory and siting approvals.

- Procure all required project materials, which are delivered to designated project staging area.

- Initiate and complete the procurement process (e.g., request for proposal, bidding) for selecting project construction contractor(s).

- Identify - and, as necessary, obtain agency approval - of a project construction contractor yard and material staging/laydown site(s).

- Prepare and issue to the selected contractor a list of non-regulatory commitments to landowners (e.g., replacement of fences affected by construction, provisions for restoration with specific herbaceous species of landscaping).

- Perform final survey and in-field staking or flagging of work areas and environmental resources, such as structure replacement locations, access road and ROW boundaries, wetland and watercourse borders, or exclusion areas.

- Perform outreach to inform the public, affected municipalities, and stakeholders/abutters about the anticipated start of project construction, as well as the Transmission Owner points-of-contact to obtain information about the project work after construction commences.

- Issue advance written notice, if required pursuant to project approvals, to regulatory agencies regarding the anticipated start date of project construction.

In addition, depending on the scope and complexity of the project, the project manager may schedule a pre-construction kick-off meeting or site walkdown with the construction contractor(s) and project team to review the final project plans, permit/siting conditions, safety specifications, outage constraints, and other key requirement. The objectives of the meeting are to assure that the contractor(s) are fully cognizant of the project-specific construction requirements, sensitive environmental resources, work hour restrictions, and stakeholder commitments. During the kick-off meeting, roles and responsibilities of the project team are typically explained.

Section 7 Project Execution and Closeout

Overview

The project execution phase extends from the initiation of construction, which commences with contractor mobilization to the designated contractor yard and then to the site or ROW, through the completion of all construction activities, including restoration.

Throughout the construction process (which extends through restoration), the project team remains directly involved, with a Transmission Owner construction representative overseeing the construction contractor's work and environmental monitoring and other inspections (e.g., safety) performed to verify that the work is being completed as planned. Transmission Owner outreach representatives also continue to coordinate closely with landowners, municipalities, and other stakeholders throughout the construction process. The project manager tracks the progress of work compared to the schedule and budget and coordinates as necessary with the team to address issues. At the conclusion of the project, the project manager typically notes any lessons learned and records the final cost.

7.1 Project Execution

The execution phase of a project involves the following key tasks:

- Implement the Transmission Owner-directed monitoring/inspection programs to track and evaluate construction progress, as well as to verify compliance with all engineering specifications (i.e., IFC drawings), safety requirements, regulatory/siting approvals, and landowner commitments.

- Continue outreach efforts to inform the public, affected municipalities, and stakeholders/abutters about the status of the project work (e.g., updates to the website, periodic touch points with municipalities).

The project manager typically holds regularly scheduled project meetings with the Transmission Owner project team and construction contractor representatives to review progress and discuss the upcoming construction work and any particular key concerns associated with the work. The Transmission Owners also use various methods for keeping up to date on the construction contractor's plans, such as requiring the contractor to prepare and distribute an advance planned ("look ahead") schedule, thereby allowing the project team to determine the locations and types of activities that the contractor expects to perform and then to assess whether pro-active outreach, environmental, or safety efforts are required.

Throughout the construction process, safety and environmental compliance are principal concerns. The Transmission Owners take a pro-active approach to safety and compliance. Safety briefings are routinely held, with the construction contractors typically reviewing safety measures during daily on-site tailboard meetings at project work sites. Environmental regulatory matrices, which summarize and tabulate all the project-specific environmental requirements and commitments, may be prepared and distributed to the contractors and the in-field project team; the matrix then may be reviewed at weekly project meetings to assure that the contractor is aware of the specific requirements applicable to upcoming work.

7.2 Approach to Project Challenges

The construction process may be affected by a variety of unforeseen factors (e.g., severe weather, material delivery delays) that could require a deviation from approved project plans. In such cases, the project manager coordinates with Transmission Owner management, and as necessary may seek modifications to project regulatory approvals by filing requests to the agencies for the review and approval of project changes.

Table 7-1 lists the types of issues that could arise during a project construction, along with the pro-active approaches used to resolve each issue and thereby maintain the project schedule and budget:

Table 7-1: Examples of Potential Project Issues and Solutions

Example Issue	Potential Project Team Resolution
Severe weather events (e.g., storms that cause damage to the electric system and require project contractors to deploy from the project to facilitate transmission line repairs) can cause delays	Seek regulatory approvals for extended work hours, including work on Sundays, to preserve the schedule. If approved, conduct outreach to inform affected municipalities and stakeholders of the modified project work hours.
Supply chain disruptions cause delays in material deliveries and increase material costs. Material delays can impact the timeline, necessitating the establishment of alternative suppliers or securing critical materials in advance.	Order materials as early in the process as prudent.
A tight labor market can cause scheduling issues and increased labor costs.	Resolve issues regarding potential labor shortages through continuous workforce planning, which can contribute to a more reliable schedule while improving overall efficiencies.
Unexpected archaeological resources are uncovered during project execution.	Include plan for unanticipated archaeological material discovery as part of the project planning, including an established process for stopping construction work at the specific location until a resolution can be approved by the State Historic Preservation Office (SHPO). Approach allows work in other project areas to proceed.

In general, the project manager, along with the project team, monitors progress to identify any issues or challenges that could affect the project budget, schedule, or compliance with regulatory requirements.

Potential challenges may emerge in the form of unforeseen delays, quality control issues, safety concerns, and complexities in equipment testing and commissioning. Pro-active monitoring, open communication, and problem-solving are vital in addressing and mitigating such challenges.

Regular inspections and audits are typically used to identify deviations in quality or safety, and to verify adherence to specifications. The use of project management software in tracking of progress also enables responses to schedule or budget discrepancies.

Quality assurance and control processes are used to verify that construction activities meet established standards, reducing the risk of defects and the need for rework.

Significant changes to the cost that occur during construction will typically require additional presentations to the stakeholder committees. The specific requirements depend on the magnitude of the cost change, but at a minimum a revised TCA for the project would be submitted to ISO-NE and presented to the NEPOOL RC.

7.3 Project Closeout

The closure phase involves financial reconciliation, document updates, accounting closure, and a comprehensive review of lessons learned.

Final project close-out also may involve the submission of notices to siting or regulatory agencies that the project has been completed.

Section 8 Conclusion

Transmission asset condition management entails the ongoing efforts of dedicated personnel within each Transmission Owner's organization. The overarching objective of the asset condition process is to maintain the New England transmission system in a cost-effective efficient, safe, and environmentally sound manner and thereby to continue to provide reliable, resilient and affordable service to customers. Each asset condition project is the result of an iterative process, which reflects the full analysis of the need for the project, as well as the selection of the most appropriate alternative for resolving that need.

Overall, this approach to transmission asset condition management provides the most economical for consumers and efficient path to meet regional system reliability needs. Although the asset condition process differs slightly among the Transmission Owners, each transmission owner adopts a similar high-level approach to prudently maintaining their assets and thus assuring overall system reliability.

Acronyms and Glossary of Terms

Acronym	Description
ACSS	Aluminum Conductor Steel Supported, a common type of overhead conductor (used in recent years because while of similar size, it has an increased current carrying capability compared to ACSR)
ACSR	Aluminum Conductor Steel Reinforced, a common type of overhead conductor
ADSS	All-dielectric self-supporting fiber
AGL	Above Ground Level
ANSI	American National Standards Institute
CAIDI	Customer Average Interruption Duration Index
Conductor	A metallic wire, busbar, rod, tube or cable which serves as a path for electric current flow.
Counterpoise	Part of transmission line grounding system.
CWA	Clean Water Act (Federal)
Deadend Structure	A line structure that is designed to have the capacity to hold the lateral strain of the conductor in one direction.
Direct Embed	Transmission structure installation type in which the bottom section of each pole is placed in an excavated hole. Does not require the use of foundations or concrete. H-frame and guyed pole structures are typically direct embedded.
Drilled Shaft	Transmission structure foundation type involving the use of drilling rigs and pneumatic hammers to excavate an area for the structure foundation. Concrete is used for the foundation.
EMF	Electric and magnetic field
EPRI	Electric Power Research Institute
FAA	Federal Aviation Administration
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
Grounding System	Ground rings, placed around transmission line poles and counterpoise as required.
HPFF	High pressure fluid filled (pipe type underground cable)
HPGF	High pressure gas filled (pipe type underground cable)
IEEE	Institute of Electrical and Electronics Engineers
ISO-NE	ISO New England
kV	Kilovolt
LTC	Load Tap Changer
MAIFI	Momentary Average Interruption Frequency Index
NPCC	Northeast Power Coordinating Council
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NESC	National Electrical Safety Code
NESCOE	New England States Committee on Electricity
OPGW	Optical ground wire (a shield wire containing optical glass fibers for communication purposes)
PAC	Planning Advisory Committee
PTC	Pipe type cable (underground)
PLS-CADD	Power Line Systems - Computer Aided Design and Drafting

Acronym	Description
PTF	Pool Transmission Facilities
ROW	Right-of-way
SCADA	Supervisory Control and Data Acquisition System
Transmission Line	Any electric line operating at 69,000 or more volts.
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
UAV	Unmanned aerial vehicle (drone)
USACE	United States Army Corps of Engineers
Vault	Buried splice vault within with XLPE cables are connected; used for cable system maintenance
XLPE	Cross-linked polyethylene (solid dielectric underground cable)
XS	Cross-section (drawing)
WPE	Wood pole equivalent (transmission line steel structure, used to replace wood poles due to steel's resiliency, longevity, and cost-efficiency

Appendix A– Relevant Codes and Standards

Table A-1 lists the codes and standards considered when developing an asset condition project. The list is not exhaustive and other codes or standards may apply on a project-specific basis.

Table A-1: Summary of Principal Codes and Standards Considered in Asset Condition Projects

Code / Standard	Relevant Code/Standard Sections
National Electric Safety Code (NESC)	
	Relevant sections of the NESC include but are not limited to: Rule 012, Accepted Good Practice: Rule 012 of the NESC acknowledges that it does not provide minimum criteria for every situation, and in these situations “accepted good practice” is used. This document contains the requirements for Transmission Owner’s minimum “accepted good practice” based on industry codes and standards.
	Rule 110 Protective arrangements in electric supply stations
	Rule 092E Point of connection of grounding conductor for fences
	Rule 441 Energized conductors or parts -Minimum approach distance to energized lines or parts
	Section 23 Clearances - This section covers all clearances, including climbing spaces, involving overhead supply and communication lines.
	Section 24 Grades of construction - The grades of construction are specified in this section on the basis of the required strengths for safety.
	Section 25 Structural loadings for grades B and C – wind and ice loading on structures
	Section 26 Strength Requirements for structures
American Society of Civil Engineers (ASCE)	
	ASCE-10 Design of Latticed Steel Transmission Structures
	ASCE-91 Design of Guyed Electrical Transmission Structure
	ASCE-123 Prestressed Concrete Transmission Pole Structures Recommended Practice for Design and Installation
	ASCE-48 Design of Steel Transmission Pole Structures
	ASCE-104 Recommended Practice for Fiber-Reinforced Polymer Products for Overhead Utility Line Structures
	ASCE-113 Substation Structure Design Guide
	ASCE-141 Wood Pole Structures for Electrical Transmission Lines: Recommended Practice for Design and Use
	ASCE 24 Flood Resistant Design and Construction
American Concrete Institute (ACI)	
	CI 201.1R-08 (Guide for Conducting a Visual Inspection of Concrete in Service)
	ACI-318, Building Code Requirements for Structural Concrete (for reinforced concrete designs)
	ACI-318, 1983, Building Code Requirements for Structural Concrete (for anchor bolt bond strength and design) [
Occupational Safety and Health Administration (OSHA)	
North American Electric Reliability Corporation (NERC)	
	PRC-001 System Protection Coordination
	PRC-004 Protection System Mis-operation Identification and Correction
	PRC-005 Transmission and Generation Protection System Maintenance and Testing
	PRC-018 Disturbance Monitoring Equipment Installation and Data Reporting

Code / Standard	Relevant Code/Standard Sections
	PRC-023 Transmission Relay Loadability
	PRC-026 Relay Performance During Stable Power Swings
American Institute of Steel Construction (AISC)	
The Institute of Electrical and Electronics Engineers (IEEE)	
	IEEE 80 – Guide for Safety in AC Substation Grounding
	IEEE 605 – IEEE Guide for Bus Design in Air Insulated Substations
	IEEE 1427 – IEEE Guide for Recommended Electrical Clearances and Insulation Levels in Air Insulated Electrical Power Substations
	IEEE C37.30.1 – IEEE Standard Requirements for AC High-Voltage Air Switches Rated Above 1000V
	IEEE 979 – Guide for Substation Fire Protection
	Guide for Lightning Stroke Shielding of Substations
American National Standard Institute (ANSI)	
	ANSI Z535 – Safety Signs
	ANSI C37.32 – American National Standard for High Voltage Switches, Bus Supports, and Accessories Schedules of Preferred Ratings, Construction Guidelines and Specifications
	ANSI O5.1 Sections 5.2 and 5.3 address prohibited and permitted defects in wood poles
American Society for Testing and Materials (ASTM)	
	ASTM 123 Standard Specification for Zinc (Hot-Dip Galvanized) Coatings on Iron and Steel Products)
Aluminum Design Manual (ADM)	
	ADM Section F.1, F.2, and Table A.3.3
National Fire Protection Association (NFPA)	
	NFPA 1
	NFPA 70 National Electrical Code
	NFPA 101 Life Safety Code
	NFPA 850 Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations
	NFPA 851 Recommended Practice for Fire Protection for Hydroelectric Generating Plants
International Fire Code	
State Building Codes	

Appendix B – Design Standards

Examples of Design Standards to be considered in this process

Equipment	Standard / Issue
Insulators	Aged brown/blue glass insulators on the main bus structures may constitute a risk for a station outage and may need to be replaced. If there is a history of insulator failures at the site, it could be assumed that replacement of the rest of insulators is likely required.
Line Termination Structures	Loadings for existing line termination structures, in their current state, should be developed in accordance with NESC code in effect at the time of construction. Per NESC 253, line termination structures should be analyzed for broken conductor case that produces the maximum base overturning, dead end conditions.
Standard Substation Structures	Load development for existing substation structures (ex. Bus structures, switch structures, VT structures) should be in accordance with ASCE 113.
Rigid Bus	The mechanical loading criteria for rigid bus structures should be developed in accordance with the NESC & IEEE 605 – IEEE Guide for Bus Design in Air Insulated Substations (IEEE 605). Per Part 1 Section 16 Clause 162A, NESC requires that substation conductors be designed to handle any Short Circuit (SC) forces that can be expected at the site. Aluminum bus strength will be taken from the Aluminum Design Manual (ADM) Section F.1, F.2, and Table A.3.3. If rigid bus is welded, a reduction in strength is taken per the ADM.
Rigid Bus Supporting Structures	The rigid bus loads should be applied to the existing structures in accordance with IEEE 605 and ASCE 113.
Connections	Connections should be visually inspected. In areas where the load is being significantly increased, steel to steel bolted connections and welded connections should be evaluated using AISC with the loading methodology above. Connections and Base Plates should also be checked.
Deflection	Deflection criteria will be based on ASCE 113, Section 4.1.
Electrical Clearances	Minimum electrical clearances from energized parts shall be in accordance with the applicable standards for the location of the project. The above-grade clearances shall also take into consideration environmental considerations such as snowfall. The following codes and standards shall be complied with at a minimum: *ANSI C37.32 – American National Standard for High Voltage Switches, Bus Supports, and Accessories Schedules of Preferred Ratings, Construction Guidelines and Specifications* and *IEEE 1427 – IEEE Guide for Recommended Electrical Clearances and Insulation Levels in Air Insulated Electrical Power Substations* may be considered the minimum clearance requirements.