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Considerations in Strategic Long-Term Transmission Asset Replacement: An HVDC Case Study

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SUMMARY

Timing and identifying needs for major electric transmission asset investments are important challenges for utilities with responsibility to keep costs contained and to operate their assets consistent with good utility practice. Against the backdrop of regulatory policymaking, long-term strategic planning needs to balance three key priorities: cost to customers, reliability, and changes in future needs. These challenges are more acute in participant-funded and multi-stakeholder environments and are complicated by inevitable uncertainty. This report reviews experience from a recent long-term strategic HVDC replacement project and provides perspective for other industry participants to consider in their strategic development plans.

KEYWORDS

Strategy, Asset Management, Asset Replacement, HVDC, Long-Term Planning

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Introduction

Transmission assets are the backbone of the US electric grid, but a significant portion of those assets are aging to the end of their useful life, with US transmission assets as a whole reaching an average age of forty years as of 2020. [1]. Many transmission assets were built decades ago and require incrementally greater investments in maintenance and operating expenses. However, replacement and upgrades to assets are capital-intensive and have the potential to increase customer bills once in service. Utilities operate with limited resources, and must balance their obligation to provide reliable service with the significant investment needs of asset replacement. Consequently, utilities owning transmission lines, substations, and high-voltage direct current (HVDC) assets must make difficult choices in timing the replacement of major assets. Replacing an asset too late risks jeopardizing the reliability or resilience of the regional electric system; replacing it too early may mean that the customers were not able to leverage the full value of the asset. Specific asset types, such as HVDC facilities, require constant and close attention to asset age and spare part availability.

How should utilities approach asset replacement? This paper provides an overview of the strategic considerations underlying asset replacement for transmission-owning utilities, with potential application in other areas. It takes as a case study an ongoing plan to replace a major HVDC converter station. If executed efficiently, a replacement would provide significant regional benefits in terms of regional electricity supply, flexibility, and carbon reduction.

While many issues influence the timing and nature of major asset replacement decisions, transmission owners must balance the *cost to customers* against *reliability*, and the *future needs of the regional electric system*. As a subset of these issues, asset planners must work within the constraints of stakeholder networks, particularly for participant-funded assets (such as the HVDC asset highlighted in the case study here), or assets with co-owners (such as different utilities on each end of an interconnection). Furthermore, asset owners must operate within a strict regulatory environment, including input or approval from federal and state regulators, which can introduce new challenges in the planning process.

I. Aging Asset

Transmission supports the functioning of nationwide distribution grids and ensures access for generation resources. Aging substations, transmission lines, and other assets pose a risk to the reliability of the nation’s power grid unless maintained and replaced where appropriate. Asset management tools such as component inspections and tracking asset failure often indicate asset performance declines and suggest the need for a long-term strategy before the asset reaches the end of its useful life [2]. As a result, utility transmission planners, transmission operators, customer advocates, and regulators need to come to agreement on the balance between short and long-term ratepayer benefits in deciding on refurbishment, replacement, or upgrades to expensive assets.

For example, National Grid operates one end of a 2000 MW multi-terminal HVDC interconnection in the Northeast, including a converter station and associated transmission equipment. The system has been in commercial operation for thirty years [3], and the converter stations, typically planned for a forty-year useful life, may require refurbishment or replacement. The asset owners needed to confront several issues in the first stage of a replacement strategy, including:

- Whether the asset could continue to operate as designed with incremental replacements for specific components, such as converter transformers;
- State of the technology field for the asset, including whether replacement components are expected to be available in the future;
- Cost, in short-term capital and operating expense, to continue to operate the facility to the end of its useful life;
- Potential impact on customers if reliability and safety were jeopardized by operating asset components past their expected useful life.

Initial work on these questions led National Grid to undertake a long-term asset replacement study, including requests for information from vendors and outreach to co-owners of the interconnection. As the facility is participant-funded, any long-term asset replacement decision also requires support from the participant utilities paying for its service.

II. Key Factors for the Asset Replacement "Checklist"

Determining whether a replacement is the best option requires weighing possible tradeoffs based on limited information. An aging asset may continue to operate normally beyond its expected life but running the asset to failure could jeopardize reliability; the effective lifetime, probability of failure, and cost and time to replace are uncertain. In addition to gathering the best available data on asset characteristics, risk prioritization is critical for a replacement program. Three useful categories between which planners must balance risk are cost, reliability, and the future needs of the grid. Each category has elements of uncertainty that should be identified and understood by the asset owner.

Cost is a part of any utility decision-making process. While utilities are generally permitted to recover the costs of investments from ratepayers, public utility commissions and other bodies closely regulate the prudency of capital expenses and maintain pressure on utilities to minimize containable costs. However, in the early stages of asset replacement programs, major cost components may be subject to judgment through forecasting and estimates.

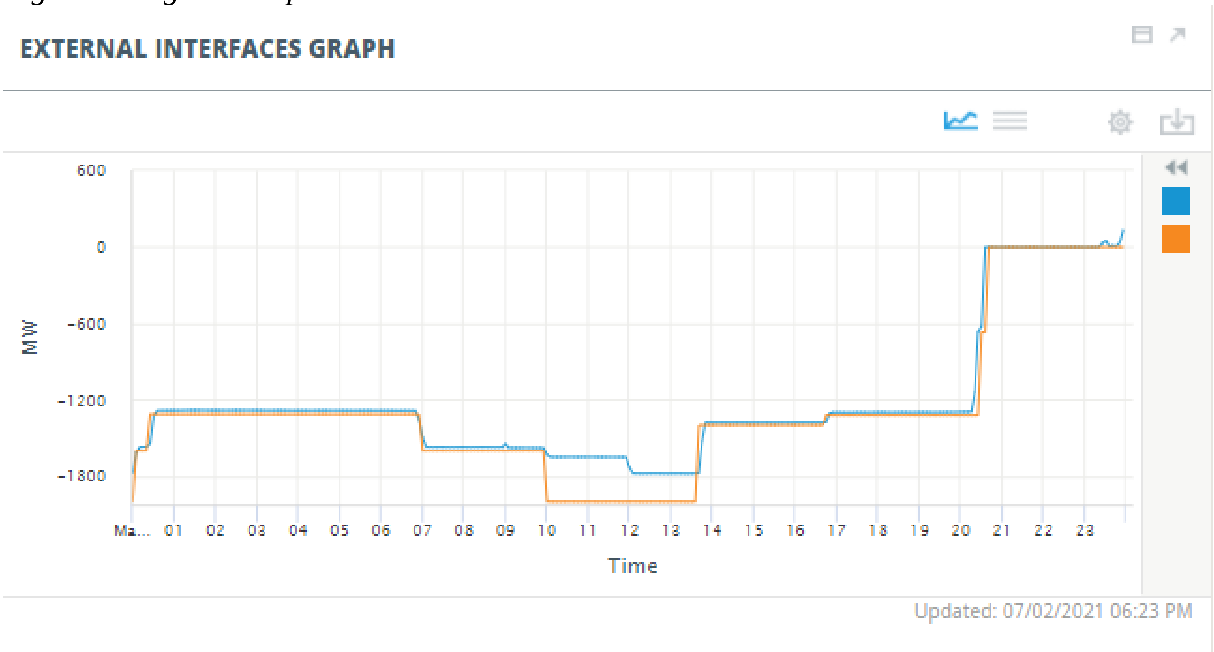
Capital expenditure figures for replacements require accuracy in gathering procurement costs, which may be challenging in sectors with limited manufacturers or limited buyers. Operating expenditures (OPEX) are difficult to predict given the wide range of inputs, and forecasting maintenance on assets is limited by tools available for asset management. The depreciation schedule for assets affects the period over which customers must pay for the asset, with longer-lived assets depreciating slowly and short-lived assets being repaid on faster timeframes. Depreciation for accounting purposes can be identified with a depreciation study but may need to be periodically reviewed by depreciation professionals. Finally, tax rates can change based on local, state/provincial, or federal tax policy.

The strategy adopted by National Grid in its analysis of potential asset replacement costs for the HVDC converter station was to break down each component individually, identify the areas of uncertainty, and conduct cost-benefit analyses under a range of assumptions, including where costs are higher or lower than expected. National Grid's HVDC replacement program encountered each of the cost challenges noted. Forecasting cost minimization scenarios required evaluating differing vendor opinions on capital needs, OPEX projections, and revenue streams. National Grid seeks to provide a cost-benefit analysis with dynamic assumptions for decision makers.

Reliability is a responsibility of any utility, but is particularly important for transmission owners with assets that connect energy sources and distribution grids, or interconnect between control areas. Participant-funded or merchant transmission assets that provide point-to-point service rely on maximizing asset availability and capacity. However, replacing an asset at the first signs of failure may be prohibitively costly for customers; likewise, waiting too long or prioritizing other projects could lead to failure and forced outages.

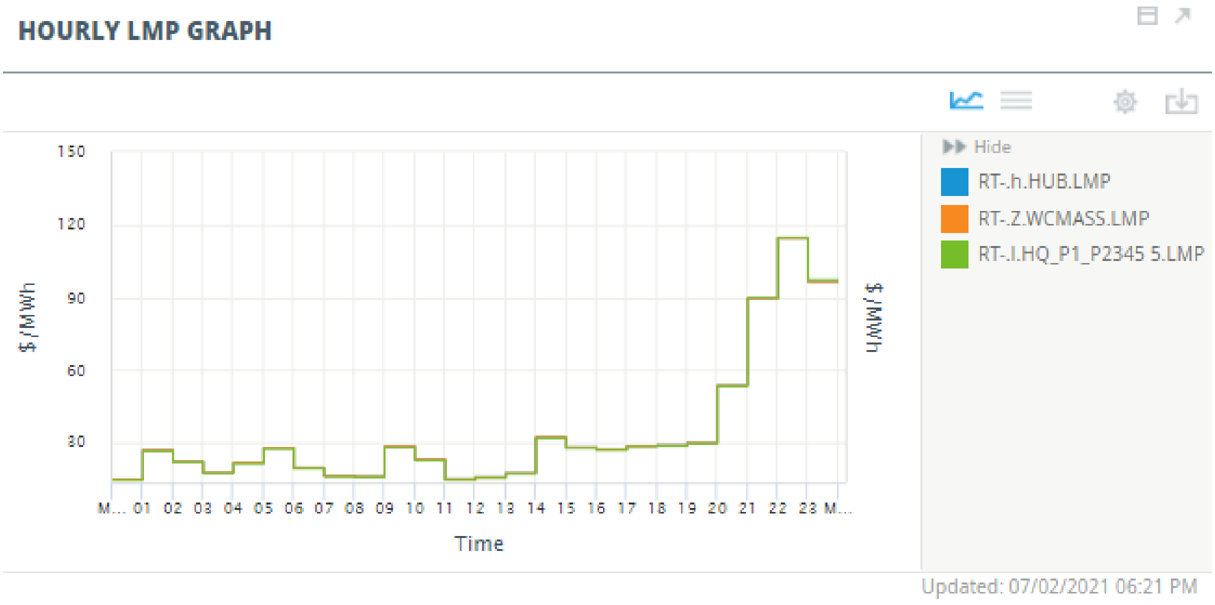
The National Grid HVDC project is facing a version of this problem: replacement options with lower up-front costs, such as rebuilding the facility on its existing footprint, require a facility shutdown during the replacement process. This shutdown would negatively impact the facility participants (who would not be able to access its benefits), but also the New England region, which would need to procure additional capacity in the interim. An unplanned outage caused by component aging and stress would likewise force a regional response handled by spinning and non-spinning reserve providers. For instance, a recent unplanned outage caused by a component failure caused a spike in regional LMPs, noted in Figure 1, 2, and 3 below from an event in May 2020 [4] (incident at approximately 20:30):

Figure 1. Regional Imports



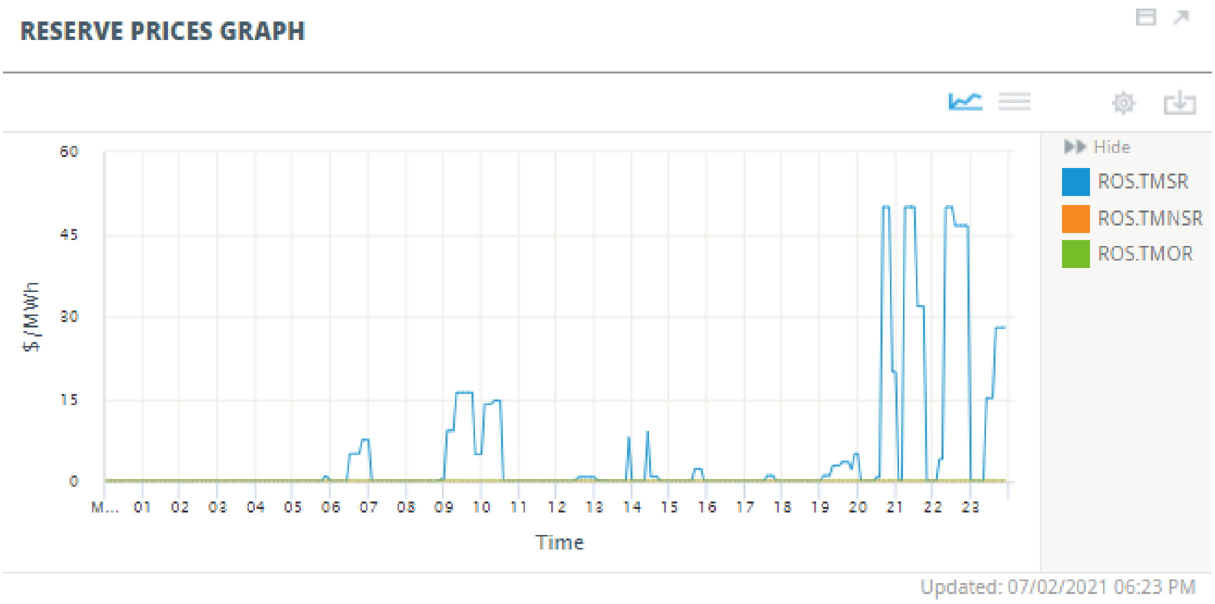
Regional imports drop from 1314 MW to zero at the time of the incident, reflecting the loss of both poles at the converter station.

Figure 2. Hourly LMP



Regional hourly locational marginal price (LMP) jump from approximately $20/MWh to approximately $115/MWh before half of converter station function is restored.

Figure 3. Reserve Prices



Reserve prices fluctuate significantly over the period of the disturbance.

In short, the loss of a major transmission asset has substantial implications for energy customers. Contingencies such as planned maintenance outages or the probability of unplanned failure outages must be considered in comparing replacement or refurbishment options.

Finally, while balancing the tradeoff between cost and reliability may be straightforward depending on a transmission owner's preferences and risk tolerance, asset managers should also consider an asset's fit in the grid of the future. With new sources of generation and energy storage coming online to meet ambitious climate targets, new services may be required to help the transmission grid function effectively. While this may require meeting regulatory mandates, it can also open possible revenue streams or change the strategic cost-benefit analysis.

For instance, stakeholders in New England have developed a series of studies intended to assist transmission planners in anticipating the grid of the future from a reliability, economic, or environmental perspective. These include, among others, the NEPOOL Future Grid Reliability Study, the New England States Committee on Electricity 2050 Transmission Study; and studies by ISO-NE on net carbon pricing. [5] These have been undertaken to anticipate the reliability and cost changes expected to reshape the electric grid with greater renewable generation to meet targets set by New England states. Adaptations to the future of the grid could include changes in real-time electricity, reserve, or ancillary market structure, which could benefit assets that support the energy transition.

In tandem with future grid reliability needs, asset owners may need to consider climate change implications as well as the policy implications of government mandates. Transmission will form an important pillar of national efforts to reduce GHG emissions along with, among other factors, changes in generation makeup and vehicle electrification. Insufficient transmission and resulting congestion patterns can leave regional grids without the ability to respond to growing customer and policy-driven demand for clean energy sources. This is a particular issue for National Grid's HVDC replacement; the use of the interconnection to import hydro power from Quebec displaces higher-cost fossil fuel resources in New England. During periods where the interconnection is unavailable, both electricity costs to customers in the region and per-megawatt regional emissions are higher. Replacement plans that result in weeks or months-long outage durations (such as an on-site brownfield replacement program) may effectively have less favorable climate outcomes.

III. Stakeholder and Regulatory Context

Notably, while the asset owner may have a preferred cost threshold or risk level, a critical piece of the puzzle to advance the asset replacement decision is the need to work with partners or stakeholders holding an advisory role or veto power over a replacement program. These concerns need to be anticipated as part of the investment process, ideally by sharing information in appropriate forums on the need for replacement and potential cost and reliability impacts. Prior to pursuing a major investment, asset owners should prepare a stakeholder management plan.

National Grid's HVDC system is participant-funded with more than twenty other utilities in New England, and the governance agreements surrounding the asset require consultation and approval for significant capital investments. In addition, while National Grid owns a converter station, transmission lines and associated equipment in Massachusetts and New Hampshire, other utilities own the transmission and converter stations in Vermont and Quebec, Canada. Consequently, any decision to invest in a replacement system could move forward only with the awareness and support of partners and stakeholders. National Grid addressed this by working directly with the converter station co-owners and is closely coordinating on the technology selection and information-gathering process. Concerns with cost and technical interoperability have been scrutinized in studies as a result.

Depending on the regulatory context, investment decisions in transmission assets often also require approval as part of rate cases, regional planning forums, or Federal Energy Regulatory Commission (FERC) processes. For instance, the participant-funding agreements that commit stakeholders to cost sharing for National Grid's HVDC facility required negotiated amendments and regulatory approval by FERC. Failing to achieve renewal or amendments to the agreements would have placed the facility on an uncertain cost recovery path, which would make long-term strategic decisions more difficult. As part of the stakeholder identification and management process, planners should identify similar regulatory "veto points" that must be passed before investments can be made and prepare a regulatory approval strategy.

IV. Conclusion

Based on market research and best practices available, National Grid is moving forward with a replacement strategy for its HVDC assets. While several elements of replacement strategy will likely remain ambiguous throughout a decision-making process, including future electricity market conditions and reliability estimates, clear understanding of key assumptions will help planners make the best decision on behalf of ratepayers.

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