

A low-angle, close-up photograph of a high-voltage transmission tower. The image shows the intricate steel lattice structure of the tower, with multiple cross-arms and insulators. The perspective creates a sense of height and scale, with the tower extending from the bottom left towards the top right of the frame. The background is a clear, light blue sky.

Advanced Transmission Technologies Procedure

**Decision Making,
Thermal Violations**

Presented To:

Indiana
Utility Regulatory
Commission



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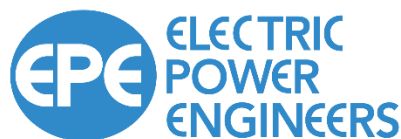
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Table of Contents

Authors.....	1
Acknowledgements	1
Table of Contents	2
List of Figures	3
List of Tables	3
1. Introduction	4
2. ATTs Feasibility Procedure.....	5
3. Decision-Making Factors.....	9
4. ATTs Decision-Making Process for Thermal Violations	15
4.1. ATT Feasibility Screening Logic	15
4.1.1. Violation Categories Decision Tree	15
4.1.2. Violated Facility Type Decision Tree	16
4.1.3. Violation Cause Decision Tree.....	18
4.2. ATT Implementation Guidelines	19
4.2.1. Advanced Conductor Implementation Feasibility Guidelines	19
4.2.2. Tower Lifting Implementation Feasibility Guidelines	21
4.2.3. Advanced Power Flow Control Implementation Feasibility Guidelines	23
4.2.4. Transmission Switching Implementation Feasibility Guidelines	26
4.2.5. Dynamic Line Rating Implementation Feasibility Guidelines.....	28
4.2.6. Alternative Technology Selection Decision Tree	30
5. Technology Comparison.....	33
6. Feasibility Procedure Extension for Annual TPL Study	36
6.1. Influence of Load Growth on ATT Feasibility and Probability	36
6.2. Influence of Generation Growth on ATT Feasibility and Probability	37
6.3. Combined Impact of Load and Generation Growth	38

List of Figures

Figure 1. Overview of the ATT Feasibility Evaluation Process for Thermal Violations	4
Figure 2. Flowchart for ATT Feasibility Assessment and Technology Selection	7
Figure 3. Decision Tree for Classifying Violation Type	16
Figure 4. Decision Tree for Assessing ATT Feasibility Based on Violated Facility Type	17
Figure 5. Decision Tree for ATT Feasibility Based on Contingency Type (Violation Cause)	19
Figure 6. SmartValve Sizing Calculator	25
Figure 7. Initial ATT Feasibility Decision Tree Incorporating Violation Type, Facility, and Contingency Logic	31
Figure 8. Technology-Specific ATT Selection Decision Tree for Thermal Violations	32

List of Tables

Table 1. Feature Set Used for ATT Feasibility Assessment	14
Table 2. Key Factors Influencing the Feasibility of Advanced Conductor Implementation	21
Table 3. Key Factors Influencing the Feasibility of Tower Lifting Implementation	22
Table 4. Key Factors Influencing the Feasibility of APFC Implementation	25
Table 5. Key Factors Influencing the Feasibility of Transmission Switching Implementation	27
Table 6. Key Factors Influencing the Feasibility of Dynamic Line Rating Implementation	30
Table 7. Comparative Summary of ATTs by Cost, Outage Duration, and Implementation Timeline	35

1. Introduction

Advanced Transmission Technologies (ATTs) offer potential solutions that can be deployed more rapidly, cost-effectively, and with less disruption to the existing grid.

This document provides a systematic procedure for screening the feasibility of these technologies in addressing thermal overloads identified through system planning studies.

The methodology presented in this report is built around a structured decision-making framework, incorporating a set of technical features, rule-based evaluations, and decision trees. Figure 1 presents a high-level overview of the ATT feasibility evaluation process, which is detailed throughout this report. The process begins with violation identification and verification, followed by the development of traditional upgrade options. This step of procedure is considered as a generic study process which is well-established in existing transmission planning and generation interconnection workflow. Followed by generic study process, the ATT decision-making process introduces a structured screening framework that includes feature extraction and sequential evaluation of violation type, facility characteristics, contingency causes, and technology-specific considerations, as discussed in Section 3 and Section 4.

Upon identifying feasible ATT options, technology-specific guidelines are applied to support the development of preliminary justifications. These justifications are ultimately enhanced by comparative insights across technologies, as presented in Section 5.



Figure 1. Overview of the ATT Feasibility Evaluation Process for Thermal Violations

2. ATTs Feasibility Procedure

To support the integration of flexible, non-traditional transmission solutions, this section presents a step-by-step procedure for evaluating the feasibility of ATTs in response to identified system violations.

Figure 2 illustrates the overall ATT feasibility evaluation process. The procedure begins following the detection of a system violation and includes the following steps:

- **Violation Verification:** This step ensures the validity of the reported violation and serves as a foundational quality check before considering any mitigation options. The verification process may include but is not limited to confirming the accuracy of facility ratings, reviewing the definition and modeling of contingencies, validating assumptions used in the study case dispatch and base case setup. This verification step is a standard practice applicable to all transmission upgrade evaluations, whether or not ATTs are under consideration. Accordingly, this step is not part of the ATTs decision making process.
- **Feature Extraction:** To evaluate the feasibility of ATTs, key attributes of the identified violation must be extracted. These features, detailed in Section 3 of this document, serve as critical inputs to the ATTs decision-making trees. The features are selected based on industry best practices, subject matter experts (SMEs) input, and the technical characteristics of the technologies. The feature extraction process will be conducted by SMEs based on study results and engineering judgment.
- **Decision-Making Process:** A “**Rule-Based System**” has been developed to evaluate the feasibility of ATTs using extracted features of each violation. This system relies on a structured set of predefined “**if-then**” rules that assess the viability of various ATTs based on specific violation characteristics. These rules are derived from industry best practices, SME knowledge, and the inherent technical capabilities and limitations of the technologies. The decision-making framework serves as a screening process to identify where ATTs are not feasible or potentially feasible. The process is implemented using a set of compressed decision trees, which are detailed in Section 4 of this document.
- **If No ATT is Feasible:** Once “**Decision-Making Process**” determines that no ATTs are feasible for a specific violation, “**Infeasibility Rationale**” should be developed. This rationale should clearly address the central question: *Why are none of the ATTs feasible for this violation?* Section 4 of this document outlines common scenarios and technical conditions under which ATT solutions are deemed infeasible and can be used to guide the preparation of this rationale. Following this determination, the next step is to identify and evaluate traditional transmission upgrade options to resolve the violation.

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- **If any ATTs might be Feasible:** Once “**Decision-Making Process**” indicates that one or more ATTs *might be* feasible for a specific violation, a “**Preliminary Feasibility Rationale**” should be prepared. This rationale must address the key question: *Why might an alternative solution be feasible for this violation?* It is important to note that this document does **not** constitute a full ATT feasibility study, which requires further technical evaluation and detailed analysis of the candidate technologies. Section 4 of this document outlines common scenarios and technical conditions under which ATT solutions might be feasible and can be used to guide the preparation of this documentation. In addition, relevant technical characteristics and considerations of ATT options may be incorporated into the rationale from the “**Alternative Transmission Technologies Framework**” document prepared by EPE.
 - **Technology Comparison for Deemed Feasible ATTs:** While the “**Decision-Making Process**” provides an initial feasibility rating (High, Medium, or Low) for each ATT option, a further comparative assessment on the deemed feasible technologies is necessary. This comparison should consider generic cost estimates, expected outage durations associated with implementing each technology, generic timeline of implementing each technology, and key technical considerations of each technology. The combination of feasibility ratings and technology comparison enables SMEs to prioritize and rank ATT options for more detailed feasibility studies. Section 5 of this document presents a comparative analysis of ATTs to support this evaluation.

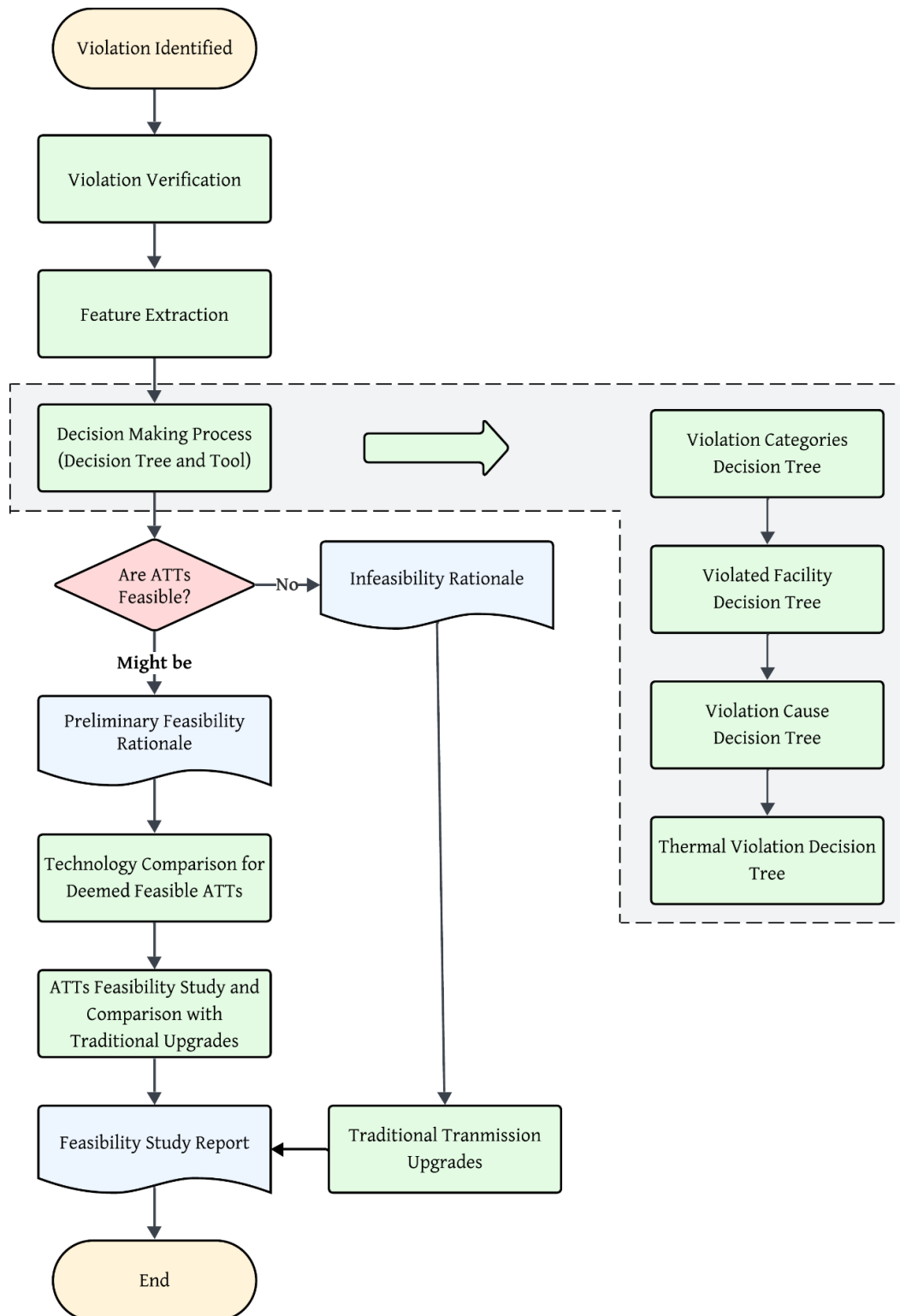


Figure 2. Flowchart for ATT Feasibility Assessment and Technology Selection

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- **ATTs Feasibility Study and Comparison with Traditional Upgrades:** Following the ranking of ATT options, a detailed feasibility study must be conducted to evaluate each alternative's technical effectiveness and system impacts. This assessment should address two key questions: (1) *Can the ATT option successfully mitigate the identified violation?*, and (2) *Does the ATT option introduce any new violations or adverse impacts to the system?* To support this analysis, the modeling methodology presented in the **"Alternative Transmission Technologies Framework"** developed by EPE could be used to simulate and assess the performance of ATT solutions. Following the feasibility study, a comprehensive comparison should be conducted to evaluate the relative advantages and disadvantages of each ATT option against traditional transmission upgrades for the identified violation.

3. Decision-Making Factors

To enable effective screening, prioritization, and selection of mitigation strategies following system violations, this section defines a comprehensive set of decision-making factors, both quantitative and qualitative, that provide insight into the frequency, scope, drivers, and contextual relevance of each violation. These factors allow transmission planners to align potential solutions with technical feasibility, planning standards, and long-term system needs. A summary of these factors is provided in

Violation Frequency: This feature quantifies the total number of times a specific monitoring facility is overloaded across different base cases and under all evaluated contingencies. A high Violation Frequency highlights persistent vulnerabilities in the system, a.k.a., weak points, and may indicate locations where some ATTs are less practical in case of consistently high AC loading levels. This feature can be extracted from reliability assessment results in simulation tool.

Contingency Impact Scope: This feature represents the total number of monitoring facilities that experience an overload under an individual contingency scenario. This factor captures the extent of the impact caused by a contingency event, indicating how widespread the violation is across the system. A higher value suggests that the contingency affects multiple parts of the system, potentially might not be mitigated by ATTs. This feature can be extracted from reliability assessment results in simulation tool.

Facility Type: This feature identifies the type of facility where the violation occurs—typically a transmission line, transformer, or breaker. While the **Contingency Impact Scope** quantifies the extent of the violation across the system, the **Facility Type** highlights the diversity of affected equipment. The primary purpose of this feature is to consider the technical limitations of ATTs in addressing overloads on certain types of facilities. For example, ATTs are generally not directly applicable to transformers or breakers. This feature can be extracted directly from simulation tool.

Voltage Level: This feature classifies the voltage level of the overloaded facility. Within the Indiana Utilities footprint, voltage levels are categorized as follows:

- Medium Voltage (Sub-Transmission) (MV): < 100 kV
- High Voltage (HV): 100 kV – 345 kV
- Extra High Voltage (EHV): ≥ 345 kV

The purpose of this feature is to consider technical challenges and installation constraints associated with deploying ATTs at different voltage tiers. For example, installing Advanced Power Flow Control (APFC) equipment at EHV levels may be impractical due to stricter ground and phase-to-phase clearance requirements. This feature can be extracted from reliability assessment results in simulation tool.

AC% Loading: This feature represents the final AC loading percentage of a monitoring facility, based on its rated capacity under base case or post-contingency conditions. It reflects how heavily a facility is loaded relative to its limit. The purpose of this feature is to account for the limitations of ATTs in mitigating severe overloads. For instance, solutions like APFC or transmission switching may be less effective or infeasible when attempting to mitigate highly loaded facilities, potentially leading to new violations elsewhere in the system. This feature can be extracted from reliability assessment results in simulation tool.

DC% Loading: Similar to AC% Loading, this feature represents the final DC loading percentage of a monitoring facility, based on its rated capacity under base case or post-contingency conditions. The purpose of this feature is to compare AC and DC loading and extract additional information that can be utilized to classify violations in different categories. This feature can be extracted from reliability assessment results in simulation tool.

dLoading: This feature represents the absolute difference between AC% Loading and DC% Loading for a given monitoring facility, based on its rated capacity under base case or post-contingency conditions. The purpose of this feature is to help classify the nature of a violation whether it is primarily thermal, voltage-related, or a combined thermal and voltage issue. Larger discrepancies between AC and DC loading can indicate voltage-driven violations, whereas smaller differences suggest primarily thermal concerns. This metric can be derived from reliability assessment results produced by simulation tool.

MW% Loading: This feature represents active power (MW) loading percentage of a monitoring facility, based on its rated capacity under base case or post-contingency conditions. It indicates how heavily a facility is loaded by active power relative to its limit. This metric is used in conjunction with **dLoading** to help classify the nature of a violation whether it is thermal, voltage-related, or both. For example, if a facility is overloaded and its MW% Loading also exceeds 100%, thermal mitigation becomes necessary. In such cases, addressing the thermal overload may also resolve any associated voltage violations. However, reactive support alone is typically insufficient to mitigate both thermal and voltage issues. This feature can be extracted from reliability assessment results in simulation tool.

dMVAR Loading: This feature represents the absolute difference in reactive power (MVAR) flow between pre- and post-contingency conditions for a given monitoring facility. A larger change in MVAR loading typically indicates a voltage-driven violation resulting from the contingency. The purpose of this feature is to help classify the nature of a violation when used alongside **dLoading** and **MW% Loading**. For example, if a facility is overloaded but its MW% Loading is below 100%, thermal mitigation may not be necessary, especially if the observed dMVAR Loading can be addressed with additional reactive support. In such cases, reactive support may be sufficient to mitigate both thermal overload and voltage violations. This feature can be extracted from reliability assessment results in simulation tool.

ConType: This feature represents the contingency type, categorized according to NERC TPL-001-5 standards (P0 through P7 and Extreme Events). Since a monitoring facility may be overloaded under multiple contingency types, selecting the most relevant one requires judgment from SMEs in the context of generation interconnection or transmission planning standards. For example, a facility might experience overloads under P2, P3, and P6 contingencies. In such cases, one option is to select the contingency type associated with the worst-case loading, ensuring that the resulting mitigation strategy resolves all associated overloads. Alternatively, some overloads, such as those from P2 or P6 events, may be addressed through load drop, as allowed by the TPL-001-5 standard. In that case, the selected mitigation strategy may not eliminate all overloads but could still comply with planning requirements. This feature should be derived from reliability assessment outputs (e.g., simulation tool), guided by SME input and aligned with applicable standards.

Facility Location: This feature identifies whether a violated facility is located in vicinity of critical facilities or even plays a critical role in overall system reliability or operational constraints, which can significantly limit the feasibility of implementing certain mitigation strategies, such as transmission switching. A facility is flagged as having a critical role if it meets one or more of the following criteria:

- Located one or two buses away from a nuclear power station.
- Controlled by an existing Remedial Action Scheme (RAS).
- High impact on short-circuit strength or stability margins, making it sensitive to topology changes.
- Part of major transfer corridors, where changes may not be practical and could affect contractual power deliveries.

Facilities meeting any of these conditions should be excluded from transmission switching evaluations as well as strategies involving significant alterations to power flow paths. This feature can be derived from a combination of network topology, RAS documentation, and short-circuit/stability studies, supported by SME input.

Radial Index: This feature represents the radiality of a monitoring facility, that is, how dependent the facility is on a single transmission path in post-contingency condition. Facilities that serve load through only one transmission source are considered radial and are assigned a Radial Index of 1. The index ranges between 0 and 1, where:

- 1.0 indicates a fully radial path (no alternate routes).
- Values close to 1 suggest that while alternate paths exist, they carry minimal flow (low Distribution Factors or DFAX), implying limited operational flexibility.
- Lower values indicate that significant flow can be distributed across alternate paths, increasing the potential for mitigation via APFC or transmission switching.

As system topology changes due to contingency occurrence, the Radial Index is contingency-dependent. Therefore, selecting the most relevant value requires SMEs judgment considering planning criteria. The index can be computed in simulation tool.

Space Availability: This feature indicates whether sufficient physical space exists at the monitoring facility to accommodate the installation of alternative technologies. It serves as a key parameter in assessing the feasibility of equipment deployment, such as APFC. For example, deploying APFC on an overloaded transmission line only 0.5 miles in length may be technically infeasible if adequate space is not available. Space availability can typically be determined from facility layout drawings or site surveys.

Limiting Element: This feature identifies the limiting element that determines the thermal or operational rating of a monitoring facility. For a given transmission line, the limiting component may be the conductor size, disconnect switch, jumper, wave trap, or ground clearance. Understanding the limiting element is essential for assessing the feasibility of alternative solutions. For example, if the rating is limited by components such as disconnect switches, jumpers, or wave traps, most ATTs will not be applicable. While if ground clearance is the constraint, then tower lifting may be a viable mitigation strategy. This feature supports solution screening and prioritization.

Load Impact (Applicable to Annual TPL Study): This feature represents the impact of load on a monitoring facility under contingency conditions. It identifies whether load growth, local area or at specific substations, aggravates (harms) or alleviates (helps) the loading on the facility, depending on how the power flows are redistributed post-contingency. Technically, the Load Impact reflects whether load growth in the vicinity of a facility contributes to additional stress on that facility, or not. Because system topology changes during contingencies, this effect is contingency-dependent. It is also substation-dependent, as different substations have different load distribution factors and injection sensitivities relative to the monitoring facility. For planning purposes, the worst-case load impact should be used to support conservative and robust mitigation strategies. This feature is particularly useful in annual TPL reliability assessments, where load growth projections play a key role in evaluating system adequacy. The Load Impact metric can be calculated using simulation tool by evaluating facility-substation pairs across relevant contingency scenarios.

Load Growth (Applicable to Annual TPL Study): This feature quantifies the anticipated load growth in neighboring substations, based on forecasted demand projections that are not yet reflected in the base cases under study. It serves as a forward-looking adjustment to better align reliability assessments with future system conditions. When combined with the Load Impact feature, Load Growth helps estimate additional/less loading on a monitoring facility under contingency scenarios. This combined estimate can be used to augment the AC% Loading to capture potential future stress that may not be evident in current base case models. Unlike Load Impact, Load Growth is a system-independent input, derived from planning forecasts. This feature is particularly useful in annual TPL reliability assessments, where Load Growth projections play a key role in evaluating system adequacy.

Generation Impact (Applicable to Annual TPL Study): Similar to Load Impact, this feature represents the impact of generation on a monitoring facility under contingency conditions. It identifies whether generation growth—local area or at specific substations—aggravates (harms) or alleviates (helps) the loading on the facility, depending on how the power flows are redistributed post-contingency. Technically, the Generation Impact reflects whether Generation growth in the vicinity of a facility contributes to

additional stress on that facility, or not. Because system topology changes during contingencies, this effect is contingency-dependent. It is also substation-dependent, as different substations have different DFAX. For planning purposes, the worst-case Generation Impact should be used to support conservative and robust mitigation strategies. This feature is particularly useful in generation interconnection reliability assessments, where generation growth projections play a key role in evaluating generation deliverability. The Generation Impact metric can be calculated using simulation tool by evaluating facility-substation pairs across relevant contingency scenarios.

Generation Growth (Applicable to Annual TPL Study): This feature quantifies the anticipated generation growth in neighboring substations, based on generation interconnection request projections that are not yet reflected in the base cases under study. It serves as a forward-looking adjustment to better align reliability assessments with future system conditions. When combined with the Generation Impact feature, Generation Growth helps estimate additional/less loading on a monitoring facility under contingency scenarios. This combined estimate can be used to augment the AC% Loading to capture potential future stress that may not be evident in current base case models. Unlike Generation Impact, Generation Growth is a system-independent input, derived from interconnection requests. This feature is particularly useful in generation interconnection reliability assessments, where Generation Growth projections play a key role in evaluating generation deliverability.

Table 1. Feature Set Used for ATT Feasibility Assessment

Feature	Description
Violation Frequency	Number of times a facility is overloaded across all base cases and contingencies.
Contingency Impact Scope	The total number of facilities overloaded under a single contingency scenario.
Facility Type	Violated facility type, transmission line, transformer, breaker.
Voltage Level	Classification of the overloaded facility's voltage level (MV, HV, EHV).
AC% Loading	Final AC loading percentage of a facility in base case or post-contingency.
DC% Loading	Final DC loading percentage of a facility in base case or post-contingency.
dLoading	Absolute difference between AC and DC loading percentages.
MW % Loading	Final MW loading percentage of a facility in base case or post-contingency.
dMVAR Loading	Absolute difference between pre- and post-contingency MVAR flows.
ConType	Type of contingency, categorized per NERC TPL-001-5 (P0–P7).
Facility Location	Indicates whether a violated facility is critical or nearby critical facilities.
Radial Index	Degree to which a facility is radial, ranging from 0 (non-radial) to 1 (fully radial).
Space Availability	Physical space availability at monitoring facility to accommodate the installation
Limiting Element	Thermal rating limiting element of a facility (e.g., conductor, wave trap, clearance).
Load Impact	Effect of load growth on a facility under contingency conditions.
Load Growth	Projected increase in load at nearby substations.
Generation Impact	Effect of generation growth on a facility under contingency conditions.
Generation Growth	Projected increase in generation at nearby substations.

4. ATTs Decision-Making Process for Thermal Violations

To systematically evaluate the feasibility and selection of ATTs in response to thermal violations, this section presents a comprehensive decision-making framework. At its core is **a rule-based system** built on predefined “**if-then**” logic that assesses the viability of ATT solutions based on key features extracted from each violation. These rules are grounded in industry best practices, SME experience, and the known technical capabilities and constraints of each technology.

The section consists of three integrated components. Section 4.1 introduces the ATT Feasibility Screening Logic, where a sequence of high-level decision trees, including violation category, facility type, and contingency cause, helps determine whether any ATT solutions are potentially viable. Upon ATTs feasibility evaluation, Section 4.2 outlines technology-specific implementation guidelines for four key solutions: advanced conductors, tower lifting, APFC, transmission switching, and Dynamic Line Rating (DLR). Finally, Section 4.3 presents a technology selection decision tree, summarizing the implementation criteria and aiding in comparative selection among feasible ATT options.

4.1. ATT Feasibility Screening Logic

This subsection introduces the initial screening process to determine whether ATTs are potentially viable for a given thermal violation. Based on stakeholder responses from the Indiana utilities, early screening of ATT applicability is an important step to rule out infeasible alternatives before proceeding with technology-specific evaluations. The initial screening consists of three structured decision trees that evaluate the nature of the violation, the type of affected facility, and the underlying contingency cause. Together, these trees form a logical pathway for ruling out infeasible cases and advancing only applicable scenarios to detailed technology evaluation.

4.1.1. Violation Categories Decision Tree

The nature of system violations can generally be classified as thermal, voltage-related, or a combination of both. The features **dLoading**, **MW% Loading**, and **dMVAR Loading** (refer to Table 1) serve as key indicators for identifying the violation type and determining appropriate mitigation strategies.

As described in Section 3, dLoading reflects reactive power flow on the monitored facility, which is typically associated with voltage violations. A high dLoading value suggests that voltage issues are contributing to the observed overload. Meanwhile, MW% Loading indicates the extent to which the facility is overloaded due to active power (MW) flow.

For instance, if a monitoring facility shows high dLoading and MW% Loading above 100%, thermal mitigation is required regardless of the voltage violation. In these cases, resolving thermal overload may also address any voltage-related issues. Conversely, if MW% Loading is below 100%, thermal mitigation

may not be necessary, especially if the observed dMVAR Loading can be mitigated through reactive power support. In such scenarios, voltage violations may be addressed solely with reactive support, avoiding the need for thermal upgrades.

Figure 3 outlines the decision tree used to determine the violation category.

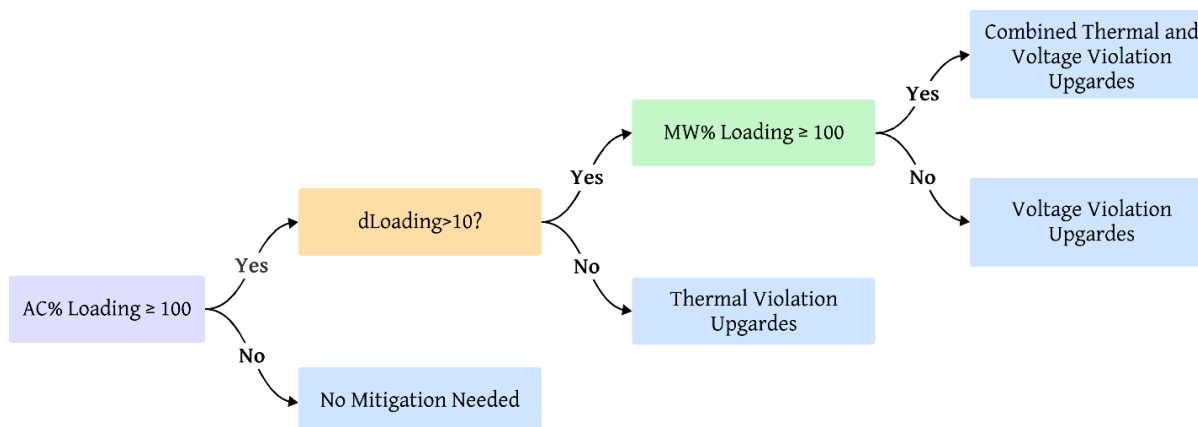


Figure 3. Decision Tree for Classifying Violation Type

4.1.2. Violated Facility Type Decision Tree

System violations may occur across a variety of facility types, including transmission lines, transformers, breakers, and other equipment such as jumpers and wave traps. In some cases, a single violation may involve a combination of these elements. The practicality of implementing ATTs depends significantly on the type of violated facility and equipment involved. Below is a summary of common facility types and considerations for ATT feasibility:

- **Transmission Lines:** When a transmission line is overloaded, ATTs may be feasible depending on two key factors: the physical length of the line and the limiting element that defines its rating. For example, if the limiting element is a jumper, ATTs are typically not viable. Similarly, for short transmission lines, solutions such as APFC may not be technically or economically justified.
- **Transformer:** If a transformer is overloaded under a contingency with a limited **Contingency Impact Scope** (i.e., the violation is limited to the transformer itself), ATTs are generally not practical compared to conventional upgrades. However, in situations where a transformer upgrade has a long lead time, temporary ATT deployment (e.g., rerouting flow) may be considered, requiring SMEs' judgment.
- **Breaker and Disconnect:** Similar to transformers, these elements offer little opportunity for ATT deployment when the violation is limited solely to the equipment. Traditional equipment upgrades are usually the only viable option.
- **Mixture of overloaded facilities:** When a contingency causes violations across a combination of facilities and equipment including transmission line, i.e., a broad **Contingency Impact Scope** and

Facility Type, certain ATTs may become viable and should be evaluated further. In most of this scenario, the mitigation plans that involve rerouting flow to resolve transmission line violation might resolve the issues for the rest of the equipment as well.

This decision logic is guided by key features outlined in Section 3, particularly Contingency Impact Scope, Facility Type, and Limiting Element. The output of this decision logic describes whether ATTs are practical or not. For example, if a transmission line is overloaded under a contingency with no other affected facilities, the ATT feasibility primarily depends on the limiting element. In contrast, if multiple transmission lines are overloaded, further SME evaluation is needed to determine whether the violations are on the same corridor, which influences ATT applicability.

In another scenario, if single facility or multiple facilities are overloaded with no transmission line overloads, such as overloaded transformers and breakers, ATTs are typically not practical compared to conventional equipment upgrades. On the other hand, if transformers and breakers are overloaded along with a transmission line, ATTs might be feasible depending on Limiting Element. In this scenario, if the rating is limited by components such as disconnect switches, jumpers, or wave traps, ATTs are generally not applicable. If the limiting factor is conductor size or ground clearance, ATTs (e.g., reconductoring, tower lifting) may be feasible.

This decision tree is designed solely to assess ATT feasibility based on facility type. If ATTs are deemed feasible, further analysis is required to identify and prioritize specific technologies, as discussed in the next sections. Figure 4 outlines the decision tree used for evaluating the feasibility of ATTs.

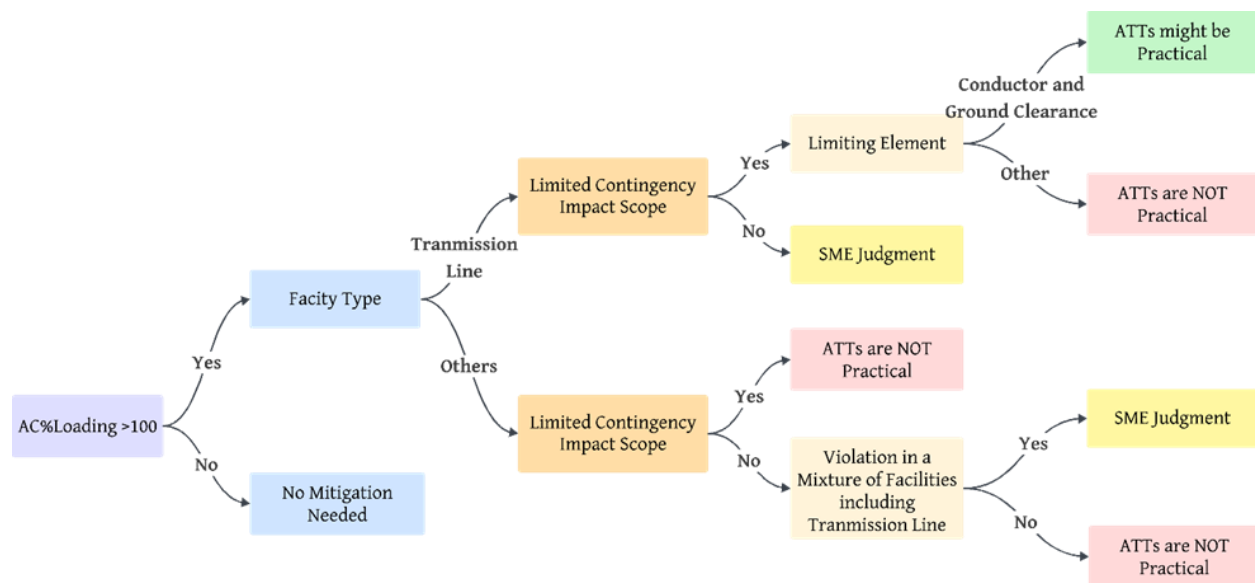


Figure 4. Decision Tree for Assessing ATT Feasibility Based on Violated Facility Type

4.1.3. Violation Cause Decision Tree

System overloads may cause from various types of contingencies, as categorized under NERC TPL-001-5 standards (P0 through P7 and extreme events). The feasibility of ATTs highly depends on the nature and classification of these contingencies.

It is important to note that this section does not evaluate the accuracy or legitimacy of contingency definitions. Rather, it assumes that all provided contingencies are valid and any resulting violations are credible. For example, certain contingencies may appear to cause reverse power flow and overload downstream facilities. However, in practice, reverse relays would typically trip the associated transformers, preventing the overload. This scenario is not considered here; the analysis focuses solely on ATT feasibility under the assumption that each contingency is properly defined.

ATTs are generally not practical for base case violations (P0), where system upgrades are typically expected. Similarly, for certain contingencies like P5 events, the preferred approach is often to eliminate the contingency altogether, such as by upgrading redundant protection systems. In these cases, ATTs are also not considered practical. Furthermore, the TPL-001-5 standard allows for some overloads to be mitigated through load shedding, depending on the contingency type and the voltage level of the overloaded facility (e.g., HV or EHV). These situations require careful judgment from SMEs to determine whether a non-infrastructure alternative (e.g., load drop) is appropriate or if a system upgrade is necessary.

It is important to note that a facility may be overloaded under multiple contingency types (i.e., **Violation Frequency** > 1). In such cases, selecting a representative contingency type (**ConType**) for mitigation planning requires SME input. For example, if a facility is overloaded under P2, P3, and P6 events, one approach is to select the contingency that results in the worst-case loading, thereby ensuring that the mitigation resolves all associated overloads. Alternatively, if overloads from P2 or P6 events can be mitigated by load drop as permitted under TPL-001-5, the selected strategy may not address all overloads, but could still remain compliant with planning standards.

This logic is intended specifically for evaluating the feasibility of ATTs based on the violation cause. If determined to be feasible, further analysis will be required to evaluate and prioritize specific technologies, as detailed in the subsequent sections. Figure 5 presents the decision tree used to assess ATT feasibility based on the underlying violation cause.

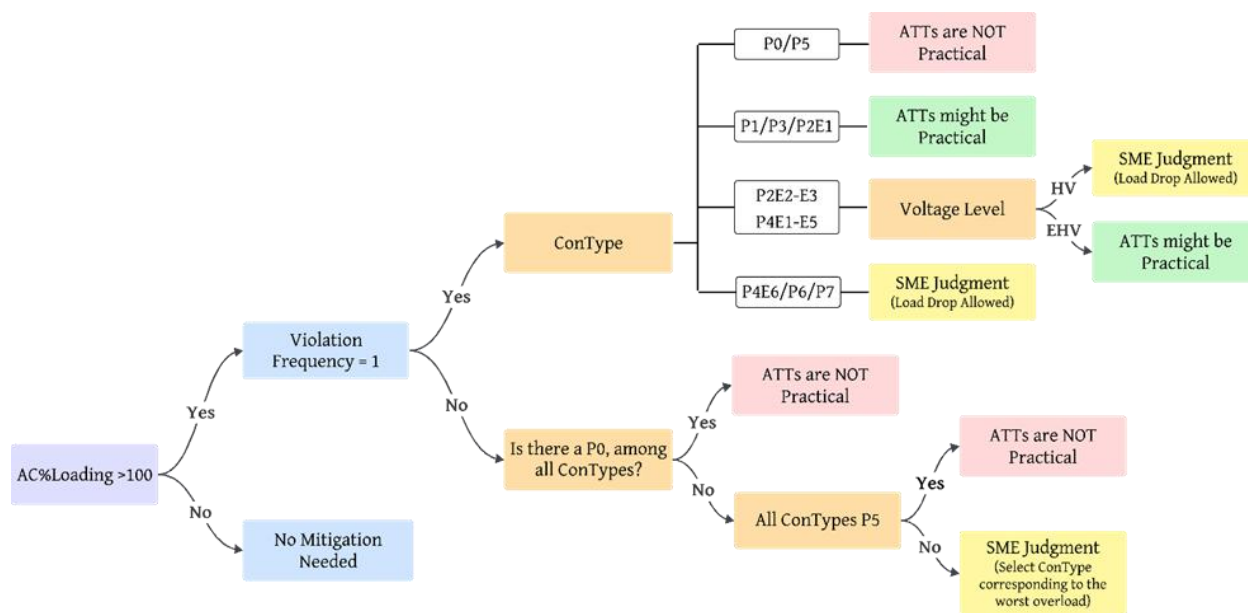


Figure 5. Decision Tree for ATT Feasibility Based on Contingency Type (Violation Cause)

4.2. ATT Implementation Guidelines

This section outlines key considerations and technical criteria for deploying specific ATTs once their feasibility has been established. These implementation guidelines serve not only as a reference for evaluating deployment practicality, but also as a structured basis for documenting both infeasibility justifications and preliminary feasibility rationales in planning reports. Each subsection provides focused insights into when and how each technology may be effectively applied.

4.2.1. Advanced Conductor Implementation Feasibility Guidelines

Generally, transmission planning projects that implement advanced conductors¹ can be categorized into three groups: reconductoring with minimal tower upgrades, rebuild projects with major tower upgrades, and new transmission line projects.

Based on input received from Indiana Utilities SMEs during stakeholder meetings, advanced conductors are being actively considered as a transmission upgrade strategy to address reliability concerns within the Indiana Utilities footprint.

Once a violation is identified, that is categorized as a thermal violation per violation category decision tree in Figure 3, and ATTs are deemed feasible per decision trees in Figure 4 and Figure 5, advanced conductors are typically considered a benchmark mitigation option in the following scenarios:

¹ Technology details and best practices are discussed in Section 1 of “Alternative Transmission Technologies Framework”.

-
- Advanced conductors might be a practical alternative to conventional upgrades if the overloaded line loading is less than 150%² of line rating, which is based on best practice implementations as well as typical range of additional ampacity provided by advanced conductors with similar weight. In this scenario, the tower upgrades might not be necessary and there would be no need for rights-of-way (RoW) expansion, which should be verified by the design team. Once the overload is between 150% to 250%, advanced conductors might be a feasible alternative solution as well, while in most cases require tower upgrades as well as minimal RoW expansion. Finally, once overload is larger than 250%, typically a new transmission line might be necessary which could be reinforced with advanced conductors.
 - Advanced conductors are typically considered as a practical alternative when the limiting element of line rating is conductor size. In addition, when the limiting element of line rating is ground clearance, advanced conductors with their low-sag characteristics may offer a practical alternative to tower lifting. Also, in scenarios to achieve long spans, especially over rivers with restricted in-river structures, advanced conductors might be an alternative solution for tower lifting solution. Additionally, advanced conductors might be preferred over tower lifting in areas with extreme weather conditions, such as high wind and ice loading, or where tower heights is restricted by aviation authorities.
 - According to best practices, advanced conductors are used across all voltage levels (MV, HV, EHV), but the intensity of their adoption and the purpose vary by level. At the MV level (<100 kV), their implementation is generally limited to areas with space constraints or elevated thermal demands, due to cost considerations. At the HV level (100–299 kV), advanced conductors are more commonly adopted to increase power transfer capacity without expanding RoW. At the EHV level (≥300 kV), they are widely used for new transmission projects.

Table 2 summarizes key features influencing the feasibility of advanced conductor implementation.

Despite the benefits of advanced conductors, lack of conductor test data limits their widespread adoption. Testing advanced conductors presents significant challenges that impede their widespread adoption. This is primarily due to the complexity, duration of required evaluations and in some cases unavailability of pre-existing test data as compared to the conventional conductor.

Advanced conductor implementation is considered a non-simulation and non-controlled solution, meaning that once it is determined to be a practical and feasible option by the engineering and design team during the planning process, no additional power flow or dynamic simulations are required. This contrasts with certain controlled ATTs, such as APFC, which may necessitate system modeling and stability verification.

² For ACSS, increased capacity is less than 25% of line rating, i.e., 125% AC% loading.

Table 2. Key Factors Influencing the Feasibility of Advanced Conductor Implementation

Key Feature	Feasibility Impact
Facility Type	Advanced conductor is viable if the overloaded facility is transmission line
Voltage Level	Applicable across all voltage levels; most common at HV for capacity expansion, and at EHV for new builds; limited at MV due to cost.
AC% Loading	Determines feasibility, overloads less than 150% likely feasible with minimal upgrades; 150–250% may require tower/RoW upgrades; overloads above 250% often requires new transmission line.
Limiting Element	If conductor size limits line rating, advanced conductors may be ideal; if ground clearance is limiting, low-sag characteristic of advanced conductors can be an alternative to tower lifting.

4.2.2. Tower Lifting Implementation Feasibility Guidelines

One of the primary thermal limitations in overhead power transmission is conductor sag, which increases as conductor temperature rises during peak load or elevated ambient conditions. As a result, the allowable thermal loading of a line might often be restricted by the minimum required clearance between the conductor and ground or underlying infrastructure. Tower lifting³ directly addresses this constraint by physically increasing the height of existing transmission structures, thereby improving conductor ground clearance. Tower lifting directly addresses this constraint by physically increasing the height of existing transmission structures, thereby restoring or improving conductor ground clearance. By elevating specific towers along a line segment, system operators can safely accommodate higher conductor operating temperatures and greater current flow without breaching clearance standards.

Based on feedback received from Indiana Utilities SMEs during stakeholder meetings, tower lifting is recognized as an established and viable mitigation strategy for addressing thermal violations within the Indiana transmission system. This suggests the existence of internal standards and experience supporting the deployment of tower lifting measures.

Once a violation is identified, that is categorized as a thermal violation per violation category decision tree in Figure 3, and ATTs are deemed feasible per decision trees in Figure 4 and Figure 5, tower lifting should be considered as a possible alternative in the following scenarios:

- Tower lifting is often the preferred alternative to traditional reconductoring when the line rating is limited primarily by inadequate ground clearance, rather than by conductor size. This is especially effective when line loading remains below approximately 150% of the existing rating. Engineering studies, including clearance assessment and structure modeling, are necessary to identify which specific towers require elevation.

³ Technology details and best practices are discussed in Section 4 of “Alternative Transmission Technologies Framework”.

- In cases where conductor size is the primary limiting element of line rating, but existing ground clearance cannot accommodate advanced conductors with higher ampacity, a combined solution involving tower lifting and advanced conductor replacement may be appropriate. This approach can support loadings up to 250% of the original line rating, assuming both sag and tension constraints are addressed. Careful coordination of structural integrity, conductor mechanical properties (e.g., tension, creep, sag), and tower design are essential to ensure feasibility.
- Industry's best practices suggest that tower lifting is generally more feasible and effective on HV and EHV lines due to greater structural clearances, mechanical robustness, and economic justification. Tower lifting was typically not implemented for MV lines, except in special cases, due to limitations on the height of structures and the cost-benefit tradeoffs.

Table 3 summarizes key features influencing the feasibility of tower lifting implementation.

Tower lifting is categorized as a non-simulation, non-controlled solution, meaning that once it is deemed feasible by the engineering and design team, no further power flow or dynamic simulations are required to validate its effect. This makes it operationally simpler compared to controlled ATTs, such as APFC devices, which typically require extensive system modeling, transient stability assessments, and protection coordination studies. Moreover, tower lifting can often be implemented with minimal outage durations by utilizing structure extensions, mobile lifting devices, or temporary support towers during construction.

Table 3. Key Factors Influencing the Feasibility of Tower Lifting Implementation

Key Feature	Feasibility Impact
Facility Type	Tower lifting is only applicable to overhead transmission lines.
Voltage Level	Most feasible for HV and EHV lines due to structural capacity and clearance; rarely used for MV lines due to limited tower height and cost-effectiveness.
AC% Loading	Most viable when loading is $\leq 150\%$ of rating; loadings up to $\sim 250\%$ may be feasible with combined tower lifting and advanced conductors; beyond that, new line likely required.
Limiting Element	Tower lifting is viable when ground clearance limits line rating; also may be combined with advanced conductors when conductor ampacity is the limiting factor and clearance is insufficient.

4.2.3. Advanced Power Flow Control Implementation Feasibility Guidelines

APFC devices enable more efficient utilization of existing transmission infrastructure by dynamically redirecting power flows away from overloaded elements and toward underutilized corridors. By reshaping real-time power flows, APFC⁴ systems can increase transfer capacity into constrained areas, such as dense urban load pockets, without requiring new transmission lines or major infrastructure investments. These devices are modular, scalable, and flexible, making them well suited for staged deployments that address near-term reliability needs while supporting long-term grid expansion strategies.

Once a violation is identified, and categorized as a thermal violation per violation category decision tree in Figure 3, and ATTs are deemed feasible per decision trees in Figure 4 and Figure 5, APFCs should be considered as a possible alternative in the following scenarios:

- APFC is only viable if the overloaded facility is not in a radial corridor in post-contingency condition, otherwise there would be no alternative corridor to reroute flow away from the overloaded facility to the unutilized corridor. Accordingly, non-radiality is a necessary, but not sufficient condition for feasibility of APFC. APFC deployment in a radial path would have no rerouting capability and is equivalent to load shedding or generation curtailment, thus considered infeasible
- APFC deployment is only viable if the alternative corridors can absorb the redirected power without exceeding their own thermal limits. Thus, APFCs are only feasible when they do not introduce secondary overloads in the system.
- Once multiple facilities are overloaded due to a contingency occurrence, APFCs might be a feasible solution if overloaded facilities all belong to the same corridor. Otherwise, separate mitigation strategies should be established to address each corridor's overload, where APFCs might not be the most effective alternative solution since mitigating overload in one corridor might inadvertently worsen conditions in another.
- APFCs might be a practical alternative to traditional transmission upgrades, where the overloaded facility is operating at 140–150% of its rated thermal capacity. Clearly, the lower the degree of overload, the greater the likelihood of APFC feasibility. Beyond this threshold, multiple APFC units may be necessary, which could compromise cost-effectiveness and operational practicality. Note that this threshold could be derived from limitations on hosting capacity of the alternative corridor and number of APFC devices needed to redirect power flow, where both limitations depend on system topology, reactance of corridors, line ratings, voltage level, etc.

⁴ Technology details and best practices are discussed in Section 2 of “Alternative Transmission Technologies Framework”.

- APFCs should generally be avoided on critical transmission lines, such as those connected to nuclear facilities. APFC deployment introduces new layers of complexity to grid operations, particularly when multiple devices are deployed across the system, where the critical lines should not be at additional risks. In addition, APFCs' mis-operation or failure to respond appropriately could lead to overloads, equipment and system stress, or violation of operating limits.
- APFC can be installed across various voltage levels. However, at EHV level (i.e., 300 kV and above), APFC installation might not be practical due to increased clearance requirements, larger insulator dimensions, and a significantly larger installation footprint. These factors often make APFC deployment at EHV impractical. In addition, the number of required APFCs increases proportionally with line rating and the square of voltage level ($\text{number of APFCs} \propto \text{Rate} \times \text{kV}^2$), meaning it increases linearly with line rating and quadratically with voltage level. Thus, for the same reactance injection, additional APFC devices are required in EHV compared to HV and MV.
- APFC deployment depends on the available physical space at the monitoring facility and the number of devices required. For facilities with limited or constrained space, conventional solutions such as reconductoring may be more practical. For instance, it might not be practical and cost-effective to accommodate APFC devices in short transmission lines. In contrast, for facilities with sufficient space to accommodate the required equipment, APFCs may offer a more cost-effective solution.
- Furthermore, considering modularity of APFCs, they can be implemented as an intermittent, short-term solution in temporary violation scenarios, such as during planned outages or when critical equipment is unavailable due to long lead times for replacement or repair, as outlined in Requirement R2.1.4 of TPL-001-5.

Table 4 summarizes key features influencing the feasibility of APFC implementation.

Despite the growing interest in APFC technologies and their demonstrated potential to improve transmission efficiency and flexibility, several technical, operational, regulatory, and economic challenges still hinder their widespread adoption, including limited field deployment experience, compatibility issues with legacy systems, cybersecurity concerns, and hurdles related to regulatory and market acceptance.

APFCs are considered a simulation-based and controlled solution, meaning that once they are determined to be a practical and feasible option by the engineering and design team during the planning process, additional power flow and dynamic simulations are required to ensure they are not introducing any violation into the system or jeopardize system stability.

Once APFC is deemed a feasible solution, the appropriate sizing and number of devices should be determined. The recommended approach involves incrementally increasing the line reactance on the overloaded facility until the overload is mitigated. After reactance adjustment, the corresponding line current should be recorded. Using the desired reactance and observed current flow, the required number of APFC units can then be calculated based on the device's performance characteristics. For instance,

Figure 6 illustrates the SmartValve sizing calculator, which determines the appropriate number of units for two device models based on the target reactance and line current.

Table 4. Key Factors Influencing the Feasibility of APFC Implementation

Key Feature	Feasibility Impact
Radial Index	APFC is only feasible on non-radial corridors where power can be rerouted; infeasible on radial paths.
Contingency Impact Scope	More effective when multiple overloaded facilities belong to the same corridor; less practical across multiple corridors.
AC% Loading	Most practical for overloads up to ~140–150% of line rating; above that, cost and operational complexity increase.
Facility Location	Avoid on lines serving critical facilities due to operational risk, complexity, and potential impact of mis-operation.
Voltage Level	Applicable at MV and HV; less practical at EHV due to size, clearance, and high number of required units.
Space Availability	APFC deployment depends on the available physical space at the monitoring facility and the number of devices required

Voltage Injection PU Using PSSE FACTS model			
SVRating	717	1434	
SV#	10-1800	10-3600	
1	0.042623511	0.021311756	
2	0.085247022	0.042623511	
3	0.127870534	0.063935267	
4	0.170494045	0.085247022	
5	0.213117556	0.106558778	
6	0.255741067	0.127870534	
7	0.298364578	0.149182289	
8	0.340988089	0.170494045	
9	0.383611601	0.1918058	
10	0.426235112	0.213117556	
11	0.468858623	0.234429311	
12	0.511482134	0.255741067	
13	0.554105645	0.277052823	
14	0.596729156	0.298364578	
15	0.639352668	0.319676334	
16	0.681976179	0.340988089	
17	0.72459969	0.362299845	
18	0.767223201	0.383611601	
19	0.809846712	0.404923356	
20	0.852470224	0.426235112	

Min MVA	40	MVA
Nominal voltage	230	
MVA Base	100	
Zbase	529	Ohms
Final X	0.02843	pu
Original X	0.01093	pu
Xinj	0.017500	pu
Xinj	9.258	Ohms
Final current	1176.46	Amps
Vinj	10891.08	Volts
Vinj	10.89	kV
10-1800	5.66	kV
SV 10-1800	1.924218807	decimals
10-3600	2.83	kV
SV 10-3600	3.848437615	decimals
SV 10-1800	2	Unit
SV 10-3600	4	Unit

	V (pu) from PSSE	10-1800	10-3600
#Of SV based on Vinj	0.44	11	21

Figure 6. SmartValve Sizing Calculator⁵

⁵ <https://www.smartwires.com/smartvalve/>

4.2.4. Transmission Switching Implementation Feasibility Guidelines

Transmission switching⁶ is a proven operational and planning tool used to alleviate congestion and mitigate thermal overloads on transmission lines. The core principle involves modifying the network topology, by opening or closing circuit breakers, to reroute power flows from overloaded elements to alternate, underutilized corridors. There are two primary forms of transmission switching:

- Switching the overloaded facility itself, redirecting power flow to a parallel corridor(s); and
- Switching another line(s) within the system that is not overloaded, which may relieve congestion elsewhere through system rebalancing. This is typically known as topology optimization.

Once a violation is identified, that is categorized as a thermal violation per violation category decision tree in Figure 3, and ATTs are deemed feasible per decision trees in Figure 4 and Figure 5, transmission switching should be considered as a possible alternative in the following scenarios:

- Transmission switching is only viable if the overloaded facility is not in a radial corridor in post-contingency situation, otherwise there would be no alternative corridor to reroute flow away from the overloaded facility to the unutilized corridor. Accordingly, non-radiality is a necessary, but not sufficient condition for feasibility of transmission switching. Transmission switching in a radial path would have no rerouting capability and is equivalent to load shedding or generation curtailment, thus considered infeasible
- Transmission switching is only viable if the alternative corridors can absorb the redirected power without exceeding their own thermal limits. Thus, transmission switching is only feasible when they do not introduce secondary overloads in the system.
- Once multiple facilities are overloaded due to a contingency occurrence, transmission switching might be a feasible solution if the overloaded facilities all belong to the same corridor. Otherwise, transmission switching is not a practical alternative.
- Transmission switching should generally be avoided on critical transmission lines, such as those connected to nuclear facilities. Transmission switching introduces new layers of complexity to grid operations, where the critical lines should not be at additional risks.
- Transmission switching sequences can be implemented across various voltage levels. However, at EHV level (i.e., 300 kV and above), transmission switching might not be practical due to typical limitations on parallel corridors.
- Transmission switching can be used as a temporary mitigation strategy when traditional transmission construction is delayed. It can also be applied to address system violations resulting from known outages, as outlined in Requirement R2.1.4 of TPL-001-5.

⁶ Technology details and best practices are discussed in Section 3 of “Alternative Transmission Technologies Framework”.

- When defining a transmission switching project, the operations team must understand the specific conditions under which switching should be implemented, as well as the scenarios in which the system can be restored to normal configuration. Therefore, the study engineer must analyze the system characteristics at the time of the violation. For example, a marginal overload occurring during a light load condition, such as in a spring off-peak scenario, may be a suitable candidate for mitigation through transmission switching.
- From a reliability standpoint, transmission switching is generally a more feasible solution for marginal violations that occur during prior outage contingencies or extreme events, rather than for single-contingency (P1) violations. This is because, when transmission switching is considered as a solution for a P1 violation, multiple prior outage scenarios must still be studied. This increases the risk of introducing new overloads when the switching action is implemented.
- Transmission switching or topology optimization are generally not viable solutions in weaker parts of the system or in areas that are poorly interconnected with the rest of the grid. As a rule of thumb, if a credible contingency occurring while the switching action is in place would create a large electrical island with multiple generation and load centers, the switching should not be considered a feasible option unless the associated risks are thoroughly assessed.

Table 5 summarizes key features influencing the feasibility of transmission switching implementation.

Despite the growing interest in transmission switching implementation, several technical, operational, and regulatory challenges still hinder their widespread adoption, including Lack of established reconfiguration protocols, cybersecurity and protection coordination, computational complexity and tool limitations.

Transmission switching is considered a simulation-based and controlled solution, meaning that once it is determined to be a practical and feasible option, additional power flow and dynamic simulations are required to ensure they are not introducing any violation into the system or jeopardizing system stability.

Table 5. Key Factors Influencing the Feasibility of Transmission Switching Implementation

Key Feature	Feasibility Impact
Radial Index	Transmission switching is only feasible on non-radial corridors where power can be rerouted; infeasible on radial paths.
Contingency Impact Scope	More effective when multiple overloaded facilities belong to the same corridor; less practical across multiple corridors.
Facility Location	Avoid on transmission lines serving critical facilities due to operational risk, complexity, and potential impact of mis-operation.
Voltage Level	Applicable at MV and HV; less practical at EHV due to operational limitations.

4.2.5. Dynamic Line Rating Implementation Feasibility Guidelines

DLR⁷ uses measured and/or forecasted weather and line-condition data to calculate the safe current-carrying capability of an overhead transmission line as conditions change. Unlike a physical upgrade, DLR does not permanently increase conductor capability or clearance; it identifies additional thermal headroom when actual conditions provide more cooling than the assumptions embedded in static or seasonal ratings.

Once a violation is identified as a thermal violation per the violation category decision tree in Figure 3, and ATTs are deemed feasible per the decision trees in Figure 4 and Figure 5, DLR should be considered with respect to the following points:

- Prior to considering DLR, utilities should establish a representative DLR profile that provides an indication of the expected rating increase under different ambient temperatures, wind speeds, and seasonal conditions. This profile can help characterize the range of incremental capacity that may reasonably be expected under typical and favorable operating conditions.
- Utilities should identify the limiting span or element that ultimately constrains the usable DLR capacity of a line. While the conductor itself may support a higher thermal rating, localized conditions such as reduced wind exposure, higher temperatures, or sag/clearance limitations at a critical span may restrict the practical rating increase for the overall line.
- DLR is most suitable for marginal to moderate overloads where the required incremental capacity can be provided frequently and reliably by favorable ambient conditions. DOE demonstrations report typical increases of approximately 10–40% above static ratings, while individual projects have observed larger gains under favorable conditions. Therefore, a practical screening range is generally an overload up to approximately 110–140% of the static rating, subject to site-specific historical and forecast weather analysis.
- Higher DLR gains can occur, but they are weather-dependent and should not be assumed as firm capacity without supporting data. DOE case studies include capacity increases of 30–44% over static ratings for NYPA and average increases of 30–70% relative to static ratings for Oncor, while Oncor observed only 6–14% over ambient-adjusted ratings. However, these higher gains represent condition-dependent capability rather than capacity that can be assumed to be consistently available when needed. Accordingly, overloads substantially above the typical 110–140% screening range should be evaluated on a site-specific basis rather than assumed feasible based on the maximum DLR gains reported in individual demonstrations.
- DLR is most valuable when the overload is correlated with conditions that also increase line cooling, such as lower ambient temperature and/or favorable wind. If the violation must be

⁷ Technology details and best practices are discussed in Section 9 of “Alternative Transmission Technologies Framework”.

resolved under all weather conditions or requires a guaranteed year-round increase in rating, DLR alone is generally not an appropriate mitigation because the available dynamic rating can fall back to, or in unfavorable conditions below, the seasonal/static value used for planning.

- Summer overloads require particular caution. High ambient temperature, strong solar heating, and low wind reduce conductor cooling, so the DLR may provide little additional capacity precisely during some peak summer hours. DLR should not be credited as a firm solution to a summer peak violation unless historical/forecast weather analysis demonstrates that sufficient dynamic rating is available during the critical hours; otherwise the overload can remain unchanged or become more restrictive than expected.
- The limiting element must be verified before DLR is considered. DLR can increase utilization only when the conductor thermal capability is the relevant adjustable limit and all other equipment and system limits remain above the calculated dynamic rating. If the facility is limited by a non-dynamic terminal component (e.g., breaker, disconnect switch, wave trap, jumper, or other equipment), DLR cannot increase the facility rating beyond that component limit.
- Clearance and sag must remain within applicable limits at every DLR value. DLR may use sag, tension, conductor temperature, or weather measurements to determine a safe current while respecting clearance. However, DLR does not correct existing physical under-clearance condition. If a span already lacks the required ground or object clearance at the applicable maximum conductor temperature, the physical constraint must be corrected (e.g., structure modification, re-tensioning, or reconductoring) before additional ampacity can be credited.
- DLR feasibility should be established using line-specific weather variability, sensor/forecast accuracy, communications availability, data quality, and fallback logic. A conservative fallback rating should be available when measurements, forecasts, or communications are unavailable or invalid.
- DLR is generally better suited to overhead transmission lines than underground cables and should be evaluated on lines where weather-driven conductor cooling materially affects ampacity. The benefit is location-specific and may vary significantly along the line; critical spans and microclimates should therefore be identified during implementation.

Table 6 summarizes key features influencing the feasibility of DLR implementation.

DLR is considered a simulation- and operations-dependent solution. Planning studies should evaluate the range of available ratings, the coincidence between overloads and weather conditions, and the consequences of rating reduction. Operational implementation requires validated calculations or sensors, short-term forecasting where applicable, communications and control-room integration, alarms/validity flags, and a defined fallback rating.

Table 6. Key Factors Influencing the Feasibility of Dynamic Line Rating Implementation

Key Feature	Feasibility Impact
Facility Type	Applicable primarily to overhead transmission lines where weather-dependent conductor thermal capability governs the usable rating.
AC% Loading	Most attractive for marginal/moderate overloads. A screening range of about 110–140% is supported by many demonstrations; higher gains are possible but should not be assumed as firm capacity without line-specific evidence. Persistent ~170% loading is generally not a DLR-only case.
Limiting Element	Feasible only when the dynamic conductor rating remains below all terminal-equipment, clearance, and system limits. Non-dynamic equipment limits cap the usable DLR.
Weather / Seasonal Correlation	High feasibility when overload periods coincide with favorable cooling. Lower feasibility for hot, low-wind summer peaks or when a firm year-round rating increase is required.
Ground Clearance / Sag	DLR must preserve required clearance and may use sag/tension/temperature data, but it does not physically correct an existing under-clearance span.
Operational / Data Requirements	Requires reliable measurements or weather data, forecast/estimation accuracy, communications, control-room integration, validity checks, and a conservative fallback rating.

4.2.6. Alternative Technology Selection Decision Tree

All implementation guidelines and feasibility considerations for ATTs, as outlined in Section 4.2, are incorporated into a structured decision-making process using two sequential decision trees, illustrated in Figure 7 and Figure 8. The decision tree in Figure 7 initiates the assessment by identifying the violation and proceeds through the feasibility screening logic described in Sections 4.1.1 to 4.1.3, which evaluates the violation category, facility type, and contingency cause.

Once ATT feasibility is confirmed through Figure 7, the process advances to Figure 8, which evaluates the viability of each specific technology: advanced conductors, tower lifting, APFC, transmission switching and DLR, using additional key technical features. This tiered structure ensures a comprehensive, consistent, and traceable evaluation of mitigation options tailored to the unique attributes of each thermal violation scenario.

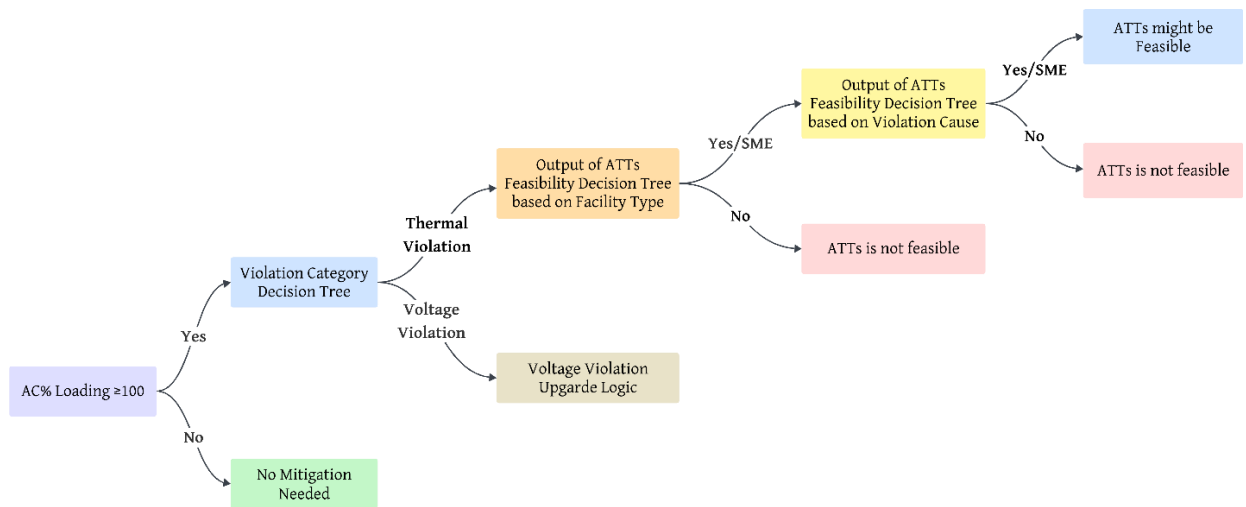


Figure 7. Initial ATT Feasibility Decision Tree Incorporating Violation Type, Facility, and Contingency Logic

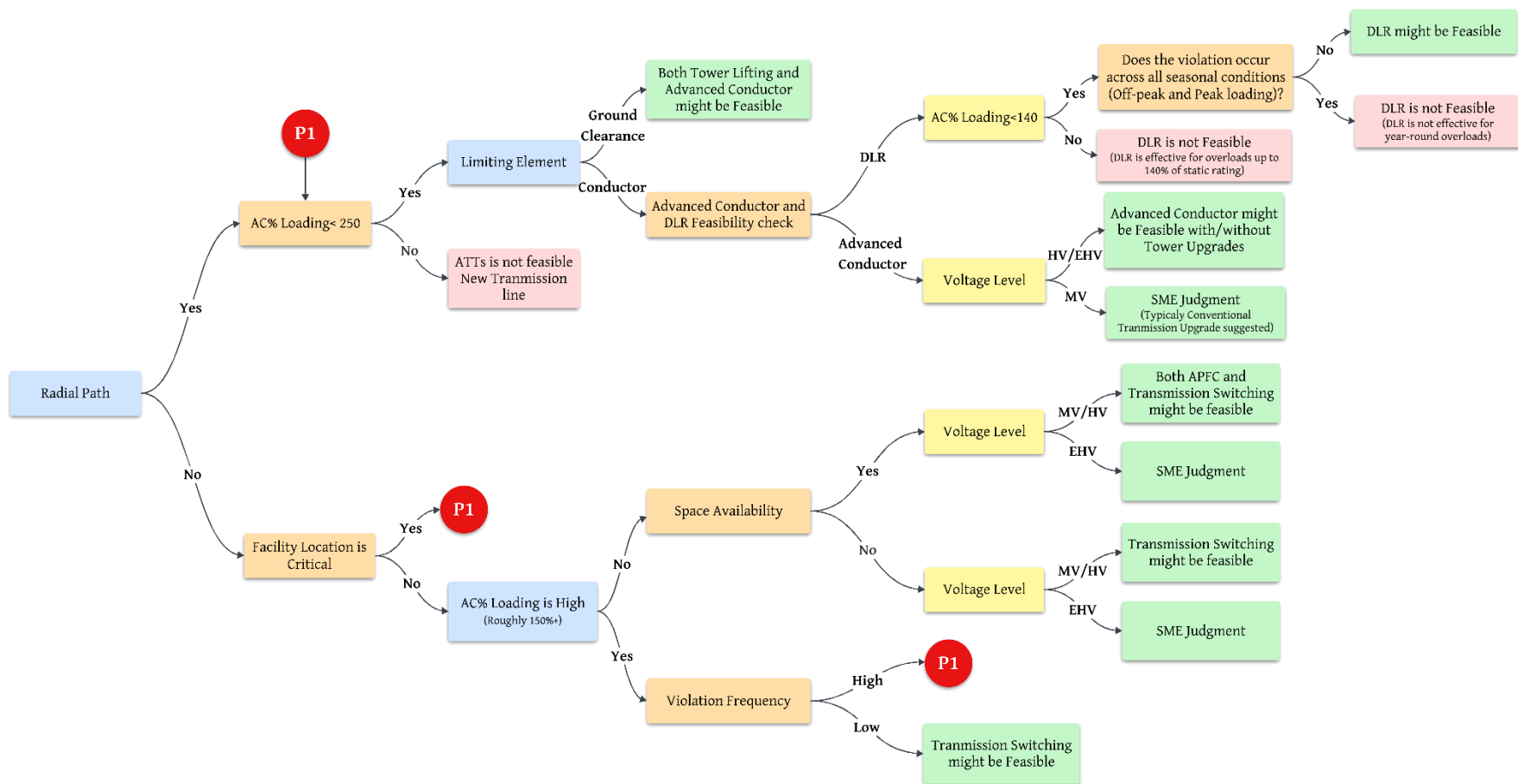


Figure 8. Technology-Specific ATT Selection Decision Tree for Thermal Violations

5. Technology Comparison

This section presents a high-level comparison of five ATTs, advanced conductors, tower lifting, APFC, transmission switching, and DLR based on their typical implementation costs, required outage durations, and overall deployment timelines. These factors are critical in evaluating and prioritizing ATT options after feasibility is established. While technical feasibility may justify a given solution, practical constraints such as extended outages or long lead times may render some technologies less desirable. Table 7 provides a side-by-side summary of key implementation parameters and considerations for each technology.

Advanced conductors typically cost between \$200,000 and \$600,000 per mile, depending on conductor type, voltage level, terrain, and installation requirements. These projects often involve extended outage durations ranging from several months to over a year, particularly when paired with structure modifications or permitting delays. The overall implementation timeline is approximately 18 to 36 months, including engineering design, permitting, procurement, and construction. Despite longer timelines, advanced conductors offer increased ampacity and reduced sag, enabling significant boost thermal ratings without the need for new ROW. However, widespread adoption remains limited by challenges such as the need for structural assessments and the lack of standardized conductor test data.

Tower lifting provides a cost-effective solution for increasing clearance and thermal capacity without expanding the transmission corridor. Its cost typically ranges from \$400,000 to \$1 million per mile equivalent, assuming 5–8 towers per mile and a unit cost of approximately \$70,000–\$150,000 per tower. Outage durations can often be minimized from energized lift to just a few days. The time to implement ranges from days to a few weeks per segment, depending on the number of towers and required engineering assessments. While tower lifting offers clear advantages in ROW-constrained environments, its standalone impact is limited unless combined with conductor upgrades, and implementation may be constrained in areas with harsh weather conditions or aviation height restrictions.

APFC devices, such as SmartValves, are priced around \$2 million per device, with overall project costs varying based on the number of units and voltage level. These systems generally require outage durations of days to weeks for installation, especially in energized environments with complex substation configurations. Full implementation timelines typically range from days to several weeks. APFC systems allow for dynamic power flow adjustments, improving utilization of underloaded corridors and reducing the need for new infrastructure. However, APFC deployments require careful coordination of protection settings, cybersecurity review, and operational planning to ensure compatibility with existing grid systems.

Transmission switching is a cost-effective and rapid ATT option, with installation costs generally ranging from \$100,000 to \$200,000 per switching scheme, depending on location and control system upgrades. It often requires only hours to a few days of outage time, particularly when switching involves breaker operations or automated controls rather than physical infrastructure changes. The implementation timeline is typically a few days, including validation of protection settings, relay coordination, and operational approvals. While transmission switching offers significant flexibility and is highly suitable for managing temporary violations or congestion, it also involves complex system studies and may introduce cybersecurity and coordination challenges in systems lacking real-time monitoring or switching protocols.

Dynamic Line Rating typically costs US \$15,000–60,000 per mile, depending on factors such as line length, number and type of monitoring devices, communication needs, and integration with utility operational systems. Because DLR relies primarily on installing monitoring equipment and associated communications on existing lines, it generally requires little to no planned outage for installation. Implementation can typically be completed within several weeks to a few months, depending on engineering, procurement, system integration, and commissioning. DLR offers a cost-effective means of increasing utilization of existing transmission assets by capturing additional thermal capacity under favorable conditions, potentially deferring more capital-intensive upgrades; however, its performance depends on weather conditions and reliable sensing, communications, and integration with operational systems.

Table 7. Comparative Summary of ATTs by Cost, Outage Duration, and Implementation Timeline

Technology	Cost Estimate	Outage Duration	Time to Implement	Technical Considerations
Advanced Conductor	USD \$200k–600k per mile	Months to over a year	18–36 Months	Pros: - Increased loading limits and high-temperature low-sag options - Suitable for climate-stressed corridors Cons: - Limited test data and long pre-deployment validation cycles - Requires detailed structural assessments and permitting
Tower Lifting	USD 400k–1M per mile Equivalent ¹	No outage or Days	Days to weeks	Pros: - Increases clearance without ROW expansion Cons: - Detailed structural assessments required - Limited effectiveness unless combined with reconductoring - Implementation limitation in areas with extreme weather conditions
APFC (Smart Valve)	USD \$2M per Device	Days to weeks	Days to weeks	Pros: - Deployable in modular form to temporarily mitigate constraints - Providing reactive power support and improving oscillation damping through real-time impedance adjustments Cons: - Requires protection and cybersecurity assessments - Adds operational complexity
Transmission Switching	USD \$100k–200k per Installation	Hours to Days	Days	Pros: - Intermittent solutions for temporary violations, e.g., planned outages or long lead time of equipment. Cons: - Computational complexity and tool limitations - Cybersecurity and protection coordination concerns
Dynamic Line Rating	USD \$15k–60k per mile	No outage or minimal outage	Weeks to months	Pros: - Increases utilization of existing transmission capacity without major physical upgrades - Relatively fast deployment Cons: - Capacity increase is weather-dependent and cannot be guaranteed year-round - Requires reliable weather/line measurements, communications, forecasting, and control-room integration

¹ Considering 5-8 towers per mile and \$70,000–150,000+ per tower

6. Feasibility Procedure Extension for Annual TPL Study

The current ATT decision-making procedure is designed to evaluate the feasibility of alternative technologies based on static base-case violation characteristics. However, Annual Transmission Planning (TPL) reliability assessments require a forward-looking perspective to ensure that mitigation strategies remain robust under evolving system conditions. In particular, load growth and generation growth projections, as well as their substation-specific impacts under contingencies, can significantly alter facility loading in future study years.

To address this, four additional features have been defined in Section 3 that are particularly relevant to TPL studies, including Load Impact, Load Growth, Generation Impact, and Generation Growth. While these features are not currently incorporated into the decision-making process or screening logic, their potential influence on ATT feasibility is non-negligible. For example, even when a violation appears marginal in a near-term study year, high projected load or generation growth could render the same violation more severe in future horizons, shifting the feasibility or priority of specific ATTs.

It is important to note that incorporating these features would increase the decision tree complexity by a factor of up to $3^4 = 81$, assuming three value ranges per feature. Moreover, this data may not always be readily available for all identified violations. As such, this section provides guidance to SMEs on how to interpret these future-looking features when applying ATT screening logic in the context of annual TPL studies.

6.1. Influence of Load Growth on ATT Feasibility and Probability

As system load increases over time, its effect on ATT feasibility depends not only on how much the load grows but also on how that load growth impacts the monitored facility under contingency conditions. Below are technology-specific considerations for interpreting Load Growth and Load Impact during ATT screening:

- **Advanced Conductors:** Substantial future load growth may push a line's loading from moderately overloaded (e.g., 130%) to severely overloaded (e.g., >250%). In such cases, conventional reconductoring with advanced conductors may no longer suffice, and a new line build may become necessary. Load growth may reduce the feasibility probability from *High* to *Low*.

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- **Tower Lifting:** Tower lifting is most effective when the thermal limit is driven by ground clearance violations rather than conductor ampacity. If future load growth causes conductor temperature to rise well beyond clearance limits, tower lifting alone may not be sufficient, unless paired with advanced conductors. This may shift feasibility from *Yes* to *No*.
 - **APFC:** As load grows, overloaded corridors may require larger power flow redirection. If the alternate corridors lack hosting capacity, or multiple APFC units would be required to reroute flow, the practicality of APFCs may diminish. Thus, moderate load growth may reduce APFC probability from *Medium* to *Low*.
 - **Transmission Switching:** For violations occurring under light-load conditions, transmission switching is often a feasible, low-cost option. However, increased load may reduce margin for switching actions, or make switching-induced flow shifts ineffective, especially if nearby facilities also become constrained. Feasibility may degrade under high-growth conditions.
 - **DLR:** Increasing load may increase the magnitude and duration of thermal overloads and therefore the rating increase required from DLR. Moderate growth may reduce DLR feasibility, while substantial or persistent growth that exceeds achievable dynamic ratings may make DLR unsuitable.

6.2. Influence of Generation Growth on ATT Feasibility and Probability

Generation growth, particularly from new interconnection requests, can significantly increase stress on specific corridors depending on DFAX and contingency redistributions. Each ATT responds differently to such growth:

- **Advanced Conductors:** As new generators inject more power onto existing corridors, the overall ampacity requirements rise. If the projected growth remains within the enhanced thermal rating range of advanced conductors, feasibility remains the same. However, for *multiple queued projects* impacting the same line, feasibility may drop if reconductoring no longer suffices.
- **Tower Lifting:** If generation growth causes sag-related violations under high MVA flows, tower lifting can be an effective incremental fix, especially when combined with conductor upgrades. However, like load growth, its effectiveness diminishes as ampacity not clearance becomes the limiting factor.
- **APFC and Transmission Switching:** Generation growth may increase grid complexity and overload alternate corridors, thereby reducing hosting capacity for flow redirection. However, in systems with well-meshed topologies, APFCs and Transmission Switching may remain viable by exploiting underutilized paths. Thus, feasibility becomes site- and topology-dependent.

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- **DLR:** Generation growth, particularly from new interconnections with high DFAX on the monitored facility, may increase corridor loading and the amount of incremental capacity required from DLR. If the additional generation produces only moderate or intermittent overloads that coincide with favorable ambient conditions, DLR feasibility may remain *High* or *Medium*. However, as additional generation projects increase the required transfer capability, the needed rating increase may exceed what DLR can reliably provide, and therefore reduce feasibility of DLR.

6.3. Combined Impact of Load and Generation Growth

When both load and generation growth affect a facility, the interaction of their respective impacts must be carefully evaluated:

- If both aggravate the violation under the same contingency scenario, the overall loading trajectory is exponential, making temporary or marginal solutions infeasible. In such cases, ATT options like APFC or transmission switching may be ruled out altogether, while advanced conductors or rebuilds may be the only viable long-term solution.
- If load growth and generation growth affect the facility in opposite directions (e.g., load aggravates, generation helps), SMEs should consider the net impact and use sensitivity scenarios to determine feasibility shifts.
- In areas where load and generation both fluctuate seasonally or hourly, hybrid or modular solutions such as APFC may offer scalable mitigation pathways until more robust solutions are justified. DLR may provide flexible incremental capacity when periods of high loading coincide with favorable ambient conditions. However, if peak loading occurs during unfavorable weather conditions, the available DLR uplift may be limited, reducing its effectiveness as a mitigation option.

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