Decoupling Transmission Losses to Evaluate Long-Term Benefits of Expansion Planning

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***Abstract*—FERC order 1920 mandates the evaluation of long-term benefits for transmission expansion projects, including their impact on system losses. However, the distinction of expansion projects' impact on transmission losses from the concurrent significant load and generation changes is ambiguous and not straightforward. This work provides an approach for decoupling the impacts of changes in load, generation, and topology on the overall system losses. While the discussion on loss allocation among grid connected entities is well developed, the impact of modifications to transmission infrastructure on losses is yet to be thoroughly explored. Rather than performing computationally-demanding and time-consuming system-wide simulations, the developed approach utilizes the admittance matrix of the network to identify loss components. Additionally, the proposed loss decoupling framework enables the evaluation of transmission infrastructures' impact independently from load and generation changes. To mitigate model-dependent errors in loss estimation, the process for developing a reliable Long-Term Scenario (LTS) is presented with consideration for long-term changes in topology, generation, and large centralized loads such as data centers. Long-term loss reduction benefits of new transmission expansion plans are then estimated using the modeled LTS. Accuracy of the developed loss decoupling framework is demonstrated using the IEEE 30-Bus system and then implemented with real-world data from Dominion Energy. A correlation between loss-reduction and resolving overloading contingencies is noticed, which is expected as losses are directly correlated to the square of current flow.**

***Index Terms*—FERC order 1920, loss allocation, long-term scenario, transmission expansion planning, transmission loss reduction.**

I. Introduction

Identifying the benefits and return on investment of transmission expansion projects is a challenging task given their wide array of impacts. Order 1920 from the Federal Energy Regulatory Commission (FERC) for long-term planning requires a wider set of benefits to be considered for estimating the added value of planned transmission facilities including transmission loss reductions [1]. Unlike loss allocation among grid connected load and generation, evaluating the resulting change to system losses due to the addition/removal of individual transmission assets has not been studied extensively. Evaluating long-term loss reduction benefits is further complicated with the uncertainty in Long-Term Scenario (LTS) modeling especially with the rapid increase in large and centralized loads like data centers [2]. Hence, a framework is required to decouple the long-term impact of transmission expansion projects on system losses, while accounting for the modeling challenges of LTS.

Allocating power system losses to bus-connected load/generation is a widely investigated topic with multiple presented approaches in literature. The approach developed in [3] traces power flow of transactions in an energy market and allocates losses accordingly. Complex power is utilized to allocated losses of bilateral transactions in [4]. The authors in [5] present a current decomposition-based approach to allocate loss among grid customers. The approach in [5] decomposes injected current components in the direction of branch current to estimate the effective loss-causing current components for each customer. An approach for decoupling load and generation components is presented in [6]. Considering the impact of loss allocation on a decentralized grid business model, a decentralized peer-to-peer market clearing approach is presented in [7] taking transmission losses into consideration. Utilizing loss allocation, a model for subsidizing operational loss reduction is presented in [8].

While the available approaches provide valuable insights into loss allocation and reduction subsidies among load/generation buses, there has been no focus on evaluating the impact of long-term transmission expansion. This paper develops an approach to identify the impact of individual transmission facilities on the overall system losses. Based on circuit analysis, transmission losses are decoupled to three components representing the contribution of load, generation, and network topology. An approach for reliable LTS modeling is also presented to handle uncertainty in long-term power system changes. Mathematical derivation and basis are provided for the proposed loss-decoupling approach and implemented on the IEEE 30-bus system. Results demonstrate ability of proposed approach to accurately estimate the impact of transmission line addition/removal on system losses compared to simulation results. The developed framework is then utilized with real-world data from Dominion Energy (DE) to estimate the loss reduction benefits of transmission expansion proposals.

The remainder of the paper is organized as follows. A summary of FERC order 1920 is provided in Section II. The developed approach for decoupling transmission losses is presented in Section III. Section IV describes the LTS modeling process. Section V presents case study results. Finally, Section VI provides the concluding remarks.

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II. FERC ORDER 1920

The Federal Energy Regulatory Commission (FERC) issued order 1920 in May 2024 under the title "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation" with an update issued later in November 2024 [9], [10]. The order addresses the need for sufficient long-term planning to identify long-term transmission needs and provides a set of criteria to assess expansion proposals and evaluate their benefits. Under order 1920, transmission providers are required to study long-term needs, develop criteria for selecting transmission expansion alternatives, evaluate benefits of alternative transmission facilities, consider advanced transmission technologies, and account for state input in cost allocation and expansion planning [1]. In order to satisfy these requirements, it is essential to develop plausible Long-Term Scenarios (LTS) based on the best available data for future system changes to identify long-term needs and evaluate benefits.

Under FERC order 1920, the process of building LTS needs to consider seven factors; potential impact of laws and government policies on demand and resource mix; laws and policies promoting decarbonization and electrification; integrated resource plans; anticipated cost, performance, and availability of generation; planned resource retirement; interconnection request and potential withdrawals; and policy goals for utility. Stakeholders must then be given the opportunity to provide meaningful input on the relevant information to incorporate for plausible modeling. To comply with order 1920, the developed LTS needs to be utilized for long-term benefits assessment of transmission facilities. Transmission are obligated to evaluate a comprehensive set of seven benefits including the modernization of legacy infrastructure, the mitigation of loss-of-load probability, and efficiencies in production costs. Furthermore, the assessment must account for the alleviation of congestion resulting from transmission failures, system robustness against severe meteorological events and unforeseen contingencies, capacity cost savings realized through lowered peak energy losses, and the overall minimization of transmission line losses. This work presents an LTS modeling approach based on practical assumptions and then utilizes the developed LTS to assess the impact of transmission expansion projects on transmission energy losses.

III. ESTIMATING TRANSMISSION LOSSES

Evaluating the impact of new transmission expansion plans on power system losses is an essential requirement of FERC order 1920. Electric grid losses arise from power flow in the impedance of transmission lines. Such flow is impacted by load, generation, and system topology. Although the available power flow simulation software can estimate overall system losses, computational requirements and loss decoupling challenges limit their use for evaluating the impact of new transmission infrastructure. Starting with the admittance matrix (Y_{BUS}) representation of network equations in (1), this section identifies the three loss components for load, generation, and transmission network topology. The decoupled loss components are then utilized to assess the impact of long-term expansion plans on system losses.

$$\begin{bmatrix} I_G \\ I_L \end{bmatrix} = \begin{bmatrix} Y_{GG} & Y_{GL} \\ Y_{LG} & Y_{LL} \end{bmatrix} \begin{bmatrix} V_G \\ V_L \end{bmatrix} \tag{1}$$

where I_G/I_L is current injection at generation/load buses, Y_{GG}/Y_{LL} is the admittance matrix for generation/load buses, $Y_{GL} = Y_{LG}^T$ is the admittance matrix portion between generation and load nodes, and V_G/V_L is the voltage at the generation/load buses, respectively. Equation (1) can be also expressed as follows.

$$I_G = Y_{GG}V_G + Y_{GL}V_L \tag{2}$$

$$I_L = Y_{LG}V_G + Y_{LL}V_L \tag{3}$$

The following relation can be obtained from (3).

$$V_L = -Y_{LL}^{-1}Y_{LG}V_G + Y_{LL}^{-1}I_L \tag{4}$$

By substitution of (4) into (2).

$$I_G = \left(Y_{GG} - Y_{GL}Y_{LL}^{-1}Y_{LG}\right)V_G + Y_{GL}Y_{LL}^{-1}I_L \tag{5}$$

Given the total complex power injected/drawn at generation/load nodes in (6).

$$\begin{aligned} S_G &= V_G^T I_G^* \\ S_L &= V_L^T I_L^* \end{aligned} \tag{6}$$

where S_G is the generation power injection and S_L is the load consumption. Total system losses (S_{loss}) are then estimated as the algebraic sum of all power injections as follows.

$$S_{loss} = S_G + S_L \tag{7}$$

By substitutions, the following can be obtained.

$$S_{loss} = V_G^T Y_{GG_{loss}} V_G^* + V_G^T H_{N_{loss}} I_L^* + I_L^T Z_{LL} I_L^* \tag{8}$$

where $Y_{GG_{loss}} = Y_{GG} - Y_{GL}Z_{LL}Y_{LG}$ estimates generation caused losses, $H_{N_{loss}} = Y_{GL}^* Z_{LL}^* - Y_{LG}^T Z_{LL}^T$ represents the loss caused by power flow from generation to load, and $Z_{LL} = Y_{LL}^{-1}$ is the impedance matrix of load nodes.

Power system losses are decoupled to three main components in equation (8). The first and third term represent losses resulting from power flow between generation and load buses, respectively. The second term represents power-transfer loss from generation to load nodes, based on system topology. In (8), $H_{N_{loss}}$ will be purely imaginary resulting in reactive power loss for symmetric-Y_{Bus} and will be Zero for a system with constant R/X ratio. Hence, it is evident that the topology term is significantly impacted by grid topology and transmission line design parameters. The decoupled load model enables transmission operators to estimate changes in system losses due to generation, load, and topology independently. For large systems, only the relevant terms of Equation (8), based on system topology, need to be considered for an expansion project. For example, a generation interconnection impacts only the first term. Similarly, a large project to connect generation and loads impacts the first and second terms. This property of the proposed framework is utilized to evaluate the loss-reduction benefits of transmission expansion plans.

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IV. Modeling Long-Term Power Systems Changes

Long-term modeling of power systems has been traditionally dependent on load forecasting and planned generation to satisfy such load, where the load was mainly decentralized and follows urban growth. However, the continuous growth of centralized loads introduces new geographical, social, economical, and legislative challenges [11]. In addition to sudden load increase, location specific loads influence planned generation location and requires dedicated topology changes to accommodate the resulting change in power flow patterns. Additionally, long-term changes to large systems can be computationally challenging for power flow software that require proximity to initial conditions for convergence. This section discusses the proposed approach for LTS modeling considering convergence challenges with changes in centralized loads, generation, and topology.

A. Large Centralized Loads

Industry requirements and technological advancements derive an increase in centralized data center loads to support artificial intelligence, cloud computing, big data analytics, web hosting, and enterprise applications. A recent survey identifies power availability and regulation as the leading challenge for expansion in data centers [12]. Power availability can especially be challenging in Northern Virginia as it is the largest data center market [13]. Fig. 1 shows large-load Delivery Point (DP) requests received by Dominion Energy (DE) over the period 2020–2025. While the location and load demand is provided for each DP request, there is significant uncertainty in determining which requests will eventually materialize or if there will be different requests that will materialize in different locations. Moreover, such requests are not bound by historic data and do not follow urban load growth but rather mainly depend on development plans, financial capabilities, and unilateral decisions of customers. A decision-making process is then required to identify the requests to be included in the LTS.

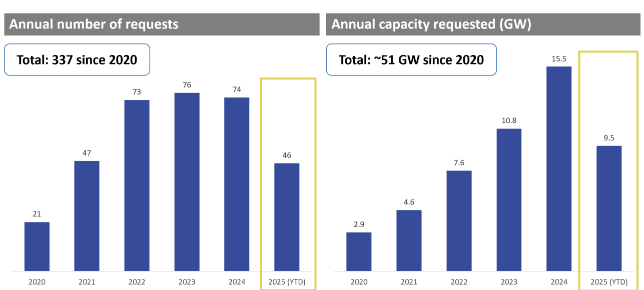

Fig. 1. DE's delivery point requests per year

Realization of DP requests is mainly impacted by five factors; system operator regulations and government legislation; interconnection capabilities of transmission system; estimated connection date; customer financial capabilities to obtain and maintain location; and the historical customers commitment data, if available. Hence, a DP realization score is estimated as a weighted summation of five coefficients representing factors of interest in this work. Coefficients are assigned values between 0 and 1, where certain realization is represented by 1 and non-feasibility corresponds to 0. Importance of different factors is reflected by set weights. Binding law and physical constraints such as legislation and interconnection capabilities are given larger weights (30% each). Connection completion time impacts both the cost of maintaining a location and consequently the willingness to commit, hence, it is given a 20% weight. Finally, cost and commitment are given 10% weight each. System operators are then able to make decisions on the DP requests to model in an LTS based on a threshold for the realization score which can be estimated as follows.

$$P_{rlz} = \sum_{i=1}^{5} \omega_i \epsilon_i \tag{9}$$

where $\omega_{i=1:5}$ are the weights and $\epsilon_{i=1:5}$ are the coefficients for legislation, interconnection capability, date, cost, and commitment, respectively.

B. Generation

Power flow in transmission networks depends on locations, output power, and voltage levels of generating units [14]. The process of modeling an LTS needs to account for such factors. While planned generation units have fixed locations, power dispatch and voltage setpoint allocations are impacted by generation offer price and performance data. Plausible power dispatch in an LTS needs to handle future offer price and performance uncertainty. To dispatch reasonable power to the new units, this work categorizes existing units based on operator, type, location, and manufacturer. The categorization groups units with similar operating cost, performance, bidding strategies, and location. Each group is then assigned a utilization factor for the utilized percentage of maximum generation capacity as follows.

$$U_k = \frac{\sum_{i=1}^{N^k} P_i / P_i^{max}}{N^k} \tag{10}$$

where U_k is the average utilization factors for group k, P_i is the allocated capacity for unit i in the group, P_i^{max} is the maximum capacity, and N^k is the number of units in the group.

Estimating suitable voltage setpoints for simultaneous addition of multiple generation units is a challenging task which is further complicated by limitations on computational power and power flow solvers. Other than generating power, generators drive grid's power flow by setting and maintaining constant voltage at type 2 (fixed active power and voltage magnitude) buses. Such constraints are upheld by power flow solvers and utilized to estimate unknown variables. Voltage level is typically set for type 2 buses during the interconnection process by the generator operator based on design voltage and required operating voltage for supporting local voltage profiles. Proposed voltage setpoint is subject to adjustments during interconnection depending on optimal power flow results to avoid overvoltage/undervoltage, maintain bus-voltage coordination with local voltage-controlled buses, or enhance

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voltage stability [15]. However, the information to perform such complex studies is not usually available for long-term planning, especially for simultanous connections of a large number of new generation units. Alternatively, a process for estimating system-wide setpoints is developed in this work by utilizing the computational features of Newton-Raphson-based power flow solvers. Given the equations for active/reactive power injection at bus i.

$$P_i = \sum_{j=1}^{n} |V_i||V_j|(G_{ij}\cos\theta_{ij} + B_{ij}\sin\theta_{ij}) \tag{11}$$

$$Q_i = \sum_{j=1}^{n} |V_i||V_j|(G_{ij}\sin\theta_{ij} - B_{ij}\cos\theta_{ij}) \tag{12}$$

where V_i is the voltage at bus i, $\theta_{ij} = \delta_i - \delta_j$ is voltage angle difference between buses i and j, G_{ij} is the real component of admittance matrix elements Y_{bus}, and B_{ij} is the imaginary component. Active/reactive power mismatch is given as.

$$\Delta P_i = P_i^{\text{spec}} - P_i^{\text{calc}}, \quad \Delta Q_i = Q_i^{\text{spec}} - Q_i^{\text{calc}} \tag{13}$$

where P_i^{spec} is the specified active power at bus i, P_i^{calc} is the calculated active power, Q_i^{spec} is the specified reactive power, and Q_i^{calc} is the calculated reactive power. Required voltage magnitude/angle changes ($\Delta|V|$ / $\Delta\delta$) are estimated based on power mismatch with the power flow Jacobian as follows.

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} \frac{\partial P}{\partial \delta} & \frac{\partial P}{\partial |V|} \\ \frac{\partial Q}{\partial \delta} & \frac{\partial Q}{\partial |V|} \end{bmatrix} \begin{bmatrix} \Delta\delta \\ \Delta|V| \end{bmatrix} \tag{14}$$

The process for updating bus voltages is repeated until a specified tolerance for mismatch is met.

$$\delta^{(k+1)} = \delta^{(k)} + \Delta\delta \tag{15}$$

$$|V|^{(k+1)} = |V|^{(k)} + \Delta|V| \tag{16}$$

To check wether voltage, active power, and reactive power are within reasonable limits, a final convergence check is performed. The proposed approaches leverages convergence tolerance and mismatch to estimate and update setpoints as shown in Fig. 2.

C. Topology

LTS modeling introduces large loads and generation units that were not present in the original system. Such interconnections change system topology either by adding the required dedicated interconnection infrastructure or, more severely, through do no harm solutions which re-rout power flow in transmission lines to resolve overloading contingencies. Identifying the required interconnection projects to accommodate the new load and generation requires a mix of experienced system knowledge and geographical information. The obvious choice is usually the geographically nearest point of connection which would require shorter transmission lines and lower cost. For most interconnections, however, this is not the case. Acquiring the required right of way and electrical overloading can prevent the choice geographical proximity. In this work, after the geographically closest point of interconnection is identified for loads and generation units, it is validated with experienced planners who could also identify better options. The entire process of LTS modeling is shown in Fig. 2 for updating load and generation power additions over N increments to facilitate the convergence of the power flow case.

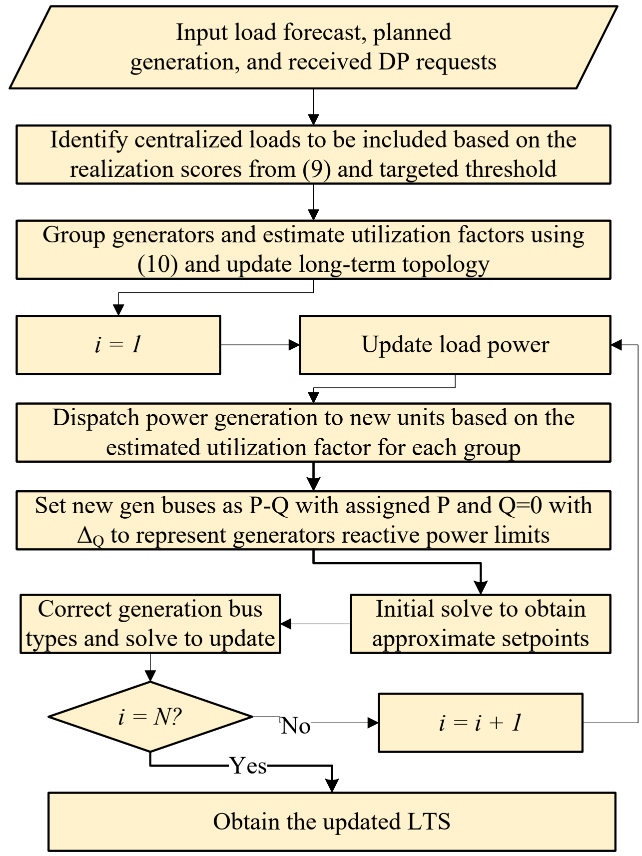

Fig. 2. Modeling LTS power flow case

V. Case Study

To validate the accuracy of the developed loss decoupling approach, it is implemented to the IEEE 30-bus system from [16] and compared to power flow simulation results from Matpower [17]. First, the impact of transmission line addition/removal on system losses is calculated as the difference between total losses in two simulations; one simulation with the line of interest connected and the other has the line disconnected. The proposed Y_{Bus}-based approach is then utilized to estimate the same difference to compare the results. Staring with the original admittance matrix for the 30-bus system, the Y_{Bus} is modified to reflect the disconnection of the line of interest and estimate losses. The approach is implemented to the seven branches forming the loop between the following buses; 6, 10, 22, 24, 25, 27, 28. Compared to Matpower's (get_loss) function, the developed Y_{Bus}-based approach was able to accurately estimated the losses for all cases. Outage of line 27-28 had the largest impact increasing the base case losses by 22%.

To add another perspective into the practicality of the developed approach, it is implemented using an LTS of Dominion Energy (DE). Starting from the 2032 base case, the LTS is modeled using real-world data to add 200^{+} generation units, 800^{+} topology elements (transformers, lines, buses, and capacitor banks), and 250^{+} of the delivery point requests shown in Fig.1. The 50^{+} GW of modeled LTS load is a significant increase compared to current peak load of 24 GW [18]. The impact of four transmission expansion projects on LTS losses is evaluated using the proposed approach. The proposal yielding the largest loss reduction consists of two-line additions (one 765KV and the other is 500KV). Moreover, the same proposal resulted in alleviating the largest number of overloading violations. The number of violations in the LTS (in red) was decreased by about 80% after adding the expansion proposal (in blue) as shown in Fig. 3. The proposal also successfully resolved all the nonconverging contingencies that resulted from the significant load additions. The coherent findings in loss and overloading results are consistent with general power system knowledge, as losses are directly correlated to the square of current flow in transmission lines. Hence, the proposed approach can also be utilized as an indication for expansion plans' ability to resolve overloading contingencies in addition to estimating loss-reduction benefits.

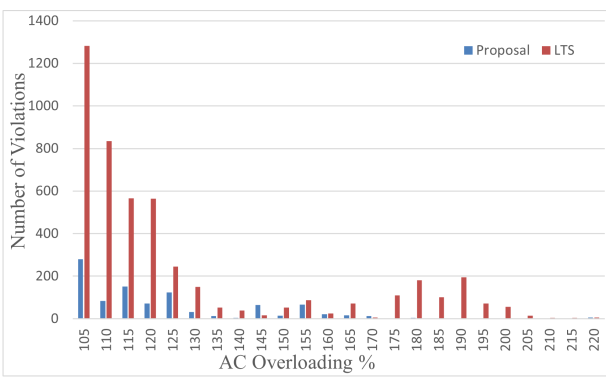

Fig. 3. LTS overloading contingencies

VI. Conclusion

An approach for decoupling losses originating from load, generation, and network topology to independently identify the impact of transmission expansion on system losses is presented in this work for complying with the requirements of FERC order 1920. The proposed approach utilizes the system bus admittance matrix Y_{Bus} rather than relying on computationally demanding simulations, which are not guaranteed to converge with abrupt system changes. Theoretical basis and mathematical derivation are provided and the proposed approach is tested using a the IEEE 30-bus system to demonstrate accuracy. The developed framework is then implemented using real-world data from Dominion Energy (DE) system. DE system continuously undergoes significant changes as they supply the largest data center market in the world and is still receiving an increasing rate of requests. To handle long-term modeling uncertainty in such practical systems, a Long-Term Scenario (LTS) building process is presented considering uncertainties in centralized loads, generation, and topology. Long-term impact of proposed expansion projects on system losses are evaluated using the proposed approach and the developed LTS. Case study results show that the expansion proposal resulting in largest loss reduction was also able to resolve the most number of overloading contingencies. Findings of this work demonstrate that the proposed approach can help in simultaneously optimizing transmission expansion for loss reduction and resolving overloading contingencies.

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