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Interdependent Expansion Planning for Resilient Electricity and Natural Gas Networks

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Abstract: This study explores enhancing the resilience of electric and natural gas networks against extreme events like windstorms and wildfires by integrating parts of the electric power transmissions into the natural gas pipeline network, which is less vulnerable. We propose a novel integrated energy system planning strategy that can enhance the systems' ability to respond to such events. Our strategy unfolds in two stages. Initially, we devise expansion strategies for the interdependent networks through a detailed tri-level planning model, including transmission, generation, and market dynamics within a deregulated electricity market setting, formulated as a mixed-integer linear programming (MILP) problem. Subsequently, we assess the impact of extreme events through worst-case scenarios, applying previously determined network configurations. Finally, the integrated expansion planning strategies are evaluated using real-world test systems.

Keywords: expansion planning; resilience networks; electric power grid; natural gas network

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1. Introduction

The resilience of energy infrastructure against extreme events like windstorms and wildfires has gained increasing attention recently [1], and this is particularly highlighted by the 2021 Texas blackouts. Enhancing energy infrastructure resilience against extreme events, such as windstorms and wildfires, to mitigate their impacts on interdependent energy systems, including electric and natural gas infrastructures, is a critical yet challenging task [2].

Traditional energy resource planning is reliability oriented, typically employing a probabilistic model focused on high-chance and low-impact events [3]. The introduction of the "defender–attacker–defender" framework, incorporating $N-k$ criteria, marks a shift toward improving system resilience against more severe scenarios [4]. In the expansion planning problem, conventional models with an $N-k$ static set are effective but often fail to account for the interactions among energy systems and the low-chance high-impact events. Meanwhile, extreme events usually come with unlikely high-impact consequences. Thus, there is a growing need for resilience-focused operational and planning methodologies.

Some researchers have delved into the concept of interdependent planning. Reference [5] proposed a co-optimization planning model that targets the long-term interdependency of electricity and natural gas systems with both economic and security constraints. Reference [6] offered an optimal planning model with reliability constraints for an integrated energy hub with multiple types of energy systems. Reference [7] developed a stochastic day-ahead hourly scheduling algorithm to dispatch both supply- and demand-side resources, and it can utilize ramping flexibility to deal with the variability of renewable energy resources over time. Reference [8] presented a flexible stochastic security-constrained unit commitment (SCUC) model to accommodate the high integration of wind energy in the midterm allocations of natural gas and hydrosystems optimally. Reference [9] presented a co-optimization algorithm to schedule the coordinated operation of the two types of energy systems in a robust way. Reference [10] focused on the optimal operation of the integrated electric and gas network with bidirectional energy conversion. However, these studies often overlooked the synergistic potential and complementary nature of combining electric and natural gas systems, especially in mitigating impacts from extreme events.

Moreover, the dynamics of the wholesale energy market are essential for effective interdependent planning [11,12]. This market, overseen by an Independent System Operator (ISO), includes transmission limitations and the process for energy market clearing, significantly affecting decisions in resource planning [13]. For example, a Generation Company (GENCO) might postpone investment if faced with severe transmission congestion [14], which can lead to a decrease in generation capacity. Alternatively, excessively expanding the transmission capacity could negatively impact generation investment since the potential for high profits often directs investments toward achieving favorable settlement prices. Therefore, optimal planning decisions require integrating transmission planning with generation planning in a market-based framework [15,16].

Therefore, this paper proposes a two-stage, robust optimization framework aimed at coordinated expansion planning to enhance resilience against extreme events. The first stage combines transmission and generation planning with market clearing to devise an optimal expansion strategy for electricity and natural gas systems. The second stage applies resilience constraints to these systems in anticipation of extreme events, utilizing robust modeling to address potential impacts. Through case studies, we demonstrate the efficacy of our integrated planning approach in enhancing energy system resilience.

The contributions of this paper are as follows:

(1) A novel framework of centralized transmission planning with decentralized generation planning is proposed. It is formulated as an integrated resource tri-level optimization model in a deregulated market environment.
(2) Detailed profiles, constraints, and market dynamics are considered in the interdependent expansion planning of energy systems to enhance its resilience.
(3) To identify promising expansion plans, a Complementary Problem (CP) reformulation is employed to address the original tri-level programming expansion challenge, while a decomposition method is applied to manage the two-stage resilience problem.

The remainder of the paper is organized as follows. In Section 2, a thorough problem description is presented to illustrate the background and framework. In Section 3, the optimal expansion model considering resilience constraints for each level is proposed, covering transmission planning, generation planning, and the market clearing process. Section 4 presents a case study of an IEEE standard test system. Finally, Section 5 summarizes the main conclusions of the paper.

2. Problem Description

The vulnerability of energy infrastructures to extreme weather events, such as windstorms and wildfires, has led to a re-evaluation of traditional energy system designs. Notably, the 2021 winter storm in Texas highlighted the comparative resilience of underground infrastructures over their overhead counterparts [17,18]. Conventionally, gas transportation networks are constructed underground, offering inherent protection against such events. Similarly, underground cable installations represent a strategic defense against the vulnerabilities faced by overhead energy facilities. While these underground solutions entail higher initial costs, their potential to significantly enhance system resilience, particularly in regions prone to extreme events, is substantial.

Thus, by considering the partial integration of power transmission infrastructure with underground gas transportation systems, this study aimed to create a more robust response mechanism to extreme events that threaten utility services. Figure 1 illustrates a system where natural gas units serve as conduits between electric power and natural gas systems, demonstrating the potential for natural gas pipelines to supplement power transmission capacities. This not only meets increased heat demands but also supports electric power delivery, presenting a comprehensive strategy for decision making in energy system planning.

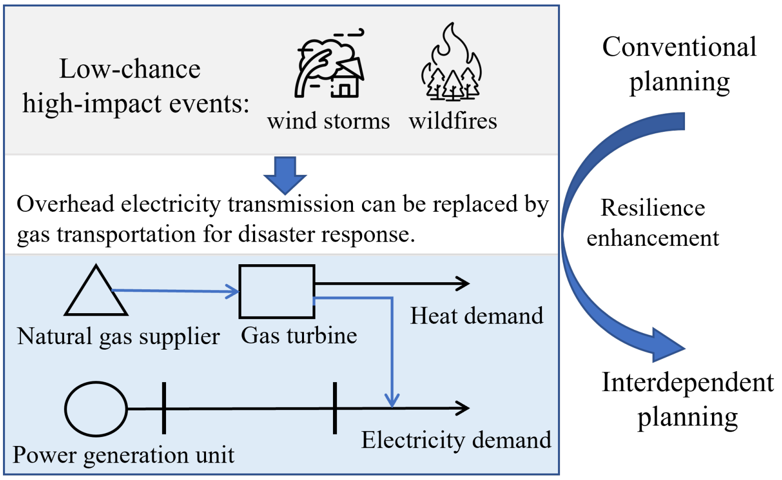

Figure 1. Interconnection of natural gas and electricity systems.

Operating a natural gas system involves complex considerations around safety, reliability, and the physical properties of gas flow. While the compressibility of natural gas offers certain operational flexibilities, such as line packing and storage, the detailed modeling of these aspects falls outside the scope of this study, which is focused on broader planning strategies rather than time-domain transient modeling or stability analysis. Moreover, it is supposed that the non-convex steady-state equations for the gas flow are excluded as well in order to reduce computational burdens in real-world integrated planning [19]. Accordingly, this work set forth specific assumptions to streamline the integrated planning process:

- The initial planning stage conceptualizes a typical hour of operation, setting the groundwork for further detailed scenario analysis in subsequent stages. This approach allows for the possibility of expanding the model to encompass various time frames and stochastic scenarios, including renewable energy outputs and demand variability.
- This work focuses on expanding the capacity of existing lines rather than constructing new ones, assuming constant impedance for any such expansions to simplify the analysis.
- Cost functions for both transmission and generation expansion are assumed as linear to minimize the computational complexity.
- Within the competitive electricity market, Generation Companies (GENCOs) are modeled to make strategic and reasonable decisions. Although each GENCO is initially represented by a single unit for simplicity, the model allows for extension to more complex configurations involving multiple units per GENCO.
- The model presumes a perfectly competitive electricity market, with the capability for all buses to support both load and generation.
- The market equilibrium is simultaneously solved through ISO's market clearing process, and the GENCOs can bid in the market.
- For Case 7 in the analysis, the installed capacities of the candidate transmission lines are set 20% lower than in Case 1.
- The scope of this study is confined to considering expansions in the natural gas transportation system's pipeline infrastructure.

3. Model Formulation

The structured two-stage optimization framework, as illustrated in Figure 2, is formulated for interdependent planning. In Stage-1 , the optimal expansion planning strategies are explored using a tri-level planning model, including a transmission level, generation level, and market level in a deregulated electricity market environment. Subsequently, Stage-2 subjects these identified expansion strategies to rigorous analysis under extreme conditions, employing worst-case scenario assessments to evaluate their robustness and effectiveness.

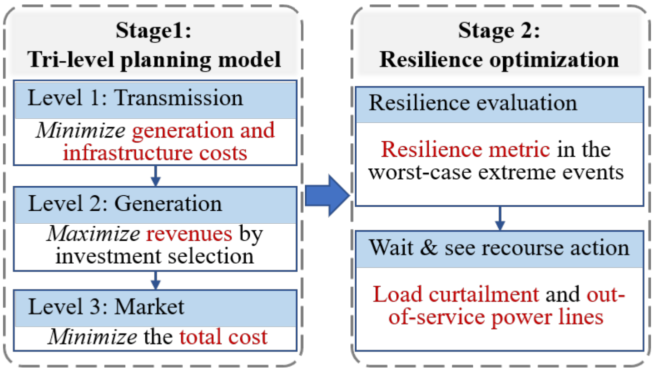

Figure 2. Configuration of two-stage problem.

3.1. Stage-1: Planning Strategy Development

The hierarchical structure of our proposed optimization framework for Stage-1 is depicted in Figure 3. This structure combines the complexities of generation and transmission planning with market clearing processes into a unified optimization model. In this framework, individual GENCOs would simulate the future power prices settled by an energy market and then obtain its investment options and corresponding operational dispatches with the new resource. These strategic decisions are related with transmission planning, as the availability of an adequate transmission capacity is crucial for GENCOs to secure additional revenue by supplying energy from new sources to consumers.

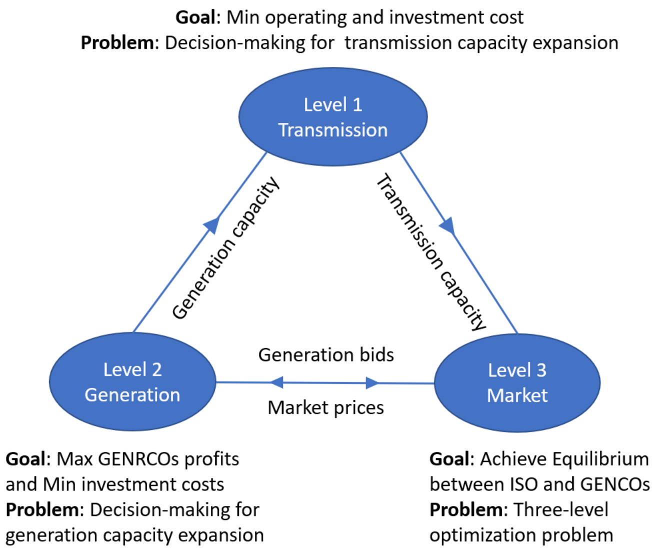

Figure 3. Hierarchical structure of the tri-level model.

Despite being in a deregulated environment, transmission system planning still remains centralized to assure the reliability of the bulk electric power grid since the ownership of transmission facilities lies with Transmission Companies (TRANSCOs). Consequently, the model assigns the responsibility of centralized transmission planning and the reliability management of the electricity market to an Independent System Operator (ISO). The generation and transmission planning issue is structured as a mixed-integer programming (MIP) problem within a tri-level framework, where centralized transmission planning decisions form the first level, followed by GENCOs' expansion strategies at the second level, and an energy market equilibrium problem at the third level.

To streamline this complex tri-level model into a more manageable form, we apply the Karush–Kuhn–Tucker (KKT) conditions to transform it into a single-level convex formulation [20]. Thus, this problem can be solved using commercially available solvers, such as CPLEX [21], directly.

3.1.1. Level-1: Transmission Expansion Planning

At Level-1, we consider enhancing the original system by introducing potential transmission lines and natural gas pipelines. These candidate lines are expected to augment the capacity of existing infrastructure. The objective function of this level, Equation (1), encompasses the operational costs of generation, capital expenditure for the addition of transmission lines and pipelines, and the investment costs from Level-2:

$$\begin{aligned} \min_{f_l^P, f_j^Q} \; & \sum_i (a_i - b_i \bar{P}_i^{GC})(P_i^{GC} + P_i^{GE}) \\ & + \sum_e a_e P_e^{GE} + \sum_i K_i \bar{P}_i^{GC} \\ & + \sum_l K_l (f_l^P - f_l^{P,0}) + \sum_j K_j (f_j^Q - f_j^{Q,0}) \end{aligned} \tag{1}$$

subject to

$$f_l^{P,0} \le f_l^P \le f_l^{P,max} \tag{2}$$

$$f_j^{Q,0} \le f_j^Q \le f_j^{Q,max} \tag{3}$$

$$\text{Level-2 solution} \tag{4}$$

Note that the decision variables $l \in L^{P,inv}$ and $j \in L^{Q,inv}$ are the transmission and pipe line capacity limits after the decisions at Level-1 are obtained. They are constants for Level-2 and Level-3. f_l^P and f_j^Q are defined as continuous ones with limits $[f_l^{P,0}, f_l^{P,max}]$ and $[f_j^{Q,0}, f_j^{Q,max}]$, respectively.

3.1.2. Level-2: Generation Expansion Equilibrium

Here, each GENCO determines its investment strategy to maximize revenue as depicted in (5). The capacity expansion of GENCO G is given by the following profit maximization expression:

$$\begin{aligned} & \max_{\bar{P}_i^{GC}} U = \\ & \sum_{i \in N^{inv}} \pi_i (P_i^{GC} + P_i^{GE}) - [a_i - b_i \bar{P}_i^{GC}](P_i^{GC} + P_i^{GE}) \\ & + \sum_{e \in N^{fix}} \pi_k P_e^{GE} - a_e P_e^{GE} - \sum_{i \in N^{inv}} K_i \bar{P}_i^{GC} \end{aligned} \tag{5}$$

subject to

$$\text{Equilibrium Constraints} \tag{6}$$

The optimization goal is to balance the revenue from energy sales against the costs of capacity expansion, as the first term is the revenues obtained from the market, and the second term is the investment cost for capacity expansion. This formulation is a Mathematical Program with Equilibrium Constraints (MPEC) model, where (6) represents the equilibrium constraints that are obtained from Level-3.

More specifically, each GENCO can decide whether to expand its capacity. However, since these expansion decisions will consider other GENCOs' expansion decisions, we plan to employ the Nash equilibrium to determine the decisions on the equilibrium of the entire power grid in the deregulated wholesale market environment. In this regard, the Nash equilibrium includes all GENCO expansion equilibrium strategies $\bar{P}_i^{GC,EQ}$, where each equilibrium strategy renders more revenues than any other methodology, $\bar{P}_i^{GC}$. It is supposed that the other GENCOs are constants in their equilibrium strategies $\bar{P}_{-i}^{GC,EQ}$. The equilibrium problem at Level-2 is subject to equilibrium constraints obtained through a perfectly competitive equilibrium; i.e., all GENCOs solve their max profit problems at the same time. Constraint (7) presents the Nash equilibrium condition.

$$\begin{aligned} & U_G^E(\bar{P}_i^{GC,E}, \forall i \in N^{inv}) \\ & \quad \geq \max_{\bar{P}_i^{GC}} U_G(\bar{P}_i^{GC}, \bar{P}_{-i}^{GC,EQ}, \forall i \in N_G^{inv}, \forall -i \in N_{-G}^{inv}) \end{aligned} \tag{7}$$

3.1.3. Level-3: Market Clearing Process

Level-3 clears the market with the resources determined previously. The model takes into account transmission constraints with a lossless DC approximation while considering competitive generators, locational marginal prices (LMPs), and inelastic demands.

The market model is divided into two components: (1) candidate generating units eligible for resource capacity expansion and (2) resources that cannot have their capacities increased through investment. In this formulation, dual variables are denoted on the right side of the equations. The problem facing the ISO in the wholesale market aims to minimize total costs, as specified in Equation (8), while adhering to constraints related to resources and the system. Specifically, Equations (9) and (10) detail the output capacities for both candidate and established units. Equation (11) accounts for the total power imported to or exported from each bus, while Equation (12) outlines the constraints on power flow. LMPs are computed based on the dual variables associated with the power balance constraints at each bus, as shown in Equation (13):

$$\min_{P_e^{GE}, P_i^{GC}, P_n^{inj}} \sum_i (a_i - b_i \bar{P}_i^{GC})(P_i^{GC} + P_e^{GE}) + \sum_e a_e P_e^{GE} \tag{8}$$

subject to

$$0 \leq P_i^{GC} \leq \bar{P}_i^{GC} \quad : \xi_i^-, \xi_i^+ \tag{9}$$

$$0 \leq P_e^{GE} \leq \bar{P}_e^{GE} \quad : \gamma_e^-, \gamma_e^+ \tag{10}$$

$$\sum_n P_n^{inj} = 0 \quad : \alpha \tag{11}$$

$$-f_l^P \leq \sum_{n \in N_{n,l}} \varphi_{l,n} P_n^{inj} \leq f_l^P \quad : \lambda_l^-, \lambda_l^+ \tag{12}$$

$$\sum_{i \in N_{i,n}} P_i^{GC} + \sum_{i \in N_{e,n}} P_e^{GE} + P_n^{inj} = P_n^D \quad : \pi_n \tag{13}$$

$$\begin{aligned} & S_m - Q_m^D - c_e P_e^{GE} - c_i P_i^{GC} \\ & \quad = \sum_{n \in N_{m,j}} Q_j^L \quad : \mu_m \end{aligned} \tag{14}$$

$$0 \leq S_m \leq S_m^{max} \quad : \sigma_m^-, \sigma_m^+ \tag{15}$$

$$-f_j^Q \leq Q_j^L \leq f_j^Q \quad : \delta_j^-, \delta_j^+ \tag{16}$$

$$\sum_j Q_j^L = 0 \quad : \beta \tag{17}$$

Constraints (14)–(17) incorporate operational protocols of the natural gas network. Specifically, Constraint (14) addresses the balance of natural gas loads at nodes and the consumption of gas by generation units following capacity expansion. Constraint (15) sets limits on the amount of fuel that can be sourced from individual natural gas nodes. Following expansion, Constraint (16) applies flow restrictions to the natural gas pipelines, assuming that these pipelines operate according to a linear transport model, rather than a nonlinear one, to simplify the planning process without sacrificing significant accuracy. Constraint (17) details the total gas imported to or exported from each node. This setup posits that gas-fired units maintain a consistent ratio of fuel usage to electricity generation, simplifying fuel usage into a piecewise linear function of power generation with minimal impact on computational complexity.

The market clearing model employed for both the market operator and participants is framed linearly, with the Karush–Kuhn–Tucker (KKT) conditions providing a sufficient framework to identify the globally optimal solution. Thus, the original multi-level problem is converted into a single-level model, streamlining the solution process. Further insights into this methodology can be found in [22]. It should be noted that the perfectly competitive environment for maximizing the revenues of generators as a whole is consistent with the economic dispatch model that is used by the market operator, and thus, it is an accurate, equivalent form of the original problems.

Accordingly, Equations (18)–(46) are an equivalent KKT formulation of the original problems set out in Equations (8)–(17). The Fortuny-Amat and McCarl linearization [23] is employed to convert the slackness conditions into linear constraints, which enhances the tractability of the optimization problem and ensures its alignment with the practical demands of energy system planning.

$$a_i - b_i \bar{P}_i^{GC} - \pi_n - \xi_i^- + \xi_i^+ + c_i \mu_m = 0 \tag{18}$$

$$a_e - \pi_n + c_e \mu_m - \gamma_e^- + \gamma_e^+ = 0 \tag{19}$$

$$\alpha - \pi_n + \sum_{l \in L} (\lambda_l^+ - \lambda_l^-) \varphi_{l,i} = 0 \tag{20}$$

$$-\mu_m - \sigma_m^- + \sigma_m^+ = 0 \tag{21}$$

$$\mu_m + \beta - \delta_j^- + \delta_j^+ = 0 \tag{22}$$

$$0 \leq \xi_i^- \leq M^{\xi_i^-} (\eta_i^{\xi^-}) \tag{23}$$

$$0 \leq P_i^{GC} \leq M^{\xi_i^-} (1 - \eta_i^{\xi^-}) \tag{24}$$

$$0 \leq \xi_i^+ \leq M^{\xi_i^+} (\eta_i^{\xi^+}) \tag{25}$$

$$0 \leq g_i - P_i^{GC} \leq M^{\xi_i^+} (1 - \eta_i^{\xi^+}) \tag{26}$$

$$0 \leq \gamma_e^- \leq M^{\gamma_e^-} (\eta_e^{\gamma^-}) \tag{27}$$

$$0 \leq P_e^{GE} \leq M^{\gamma_e^-} (1 - \eta_e^{\gamma^-}) \tag{28}$$

$$0 \leq \gamma_e^+ \leq M^{\gamma_e^+} (\eta_e^{\gamma^+}) \tag{29}$$

$$0 \leq g_e^0 - P_i^{GE} \leq M^{\gamma_e^+} (1 - \eta_e^{\gamma^+}) \tag{30}$$

$$0 \leq \lambda_l^- \leq M^{\lambda_l} (\eta_l^{\lambda^-}) \tag{31}$$

$$0 \leq f_l^P + \sum_{n \in N} \varphi_{l,n} P_n^{inj} \leq M^{f_l^P} (1 - \eta_l^{\lambda^-}) \tag{32}$$

$$0 \leq \lambda_l^+ \leq M^{\lambda_l} (\eta_l^{\lambda^+}) \tag{33}$$

$$0 \leq f_l^P - \sum_{n \in N} \varphi_{l,n} P_n^{inj} \leq M^{f_l^P} (1 - \eta_l^{\lambda^+}) \tag{34}$$

$$0 \leq \sigma_m^- \leq M^{\sigma_m^-} (\eta_m^{\sigma^-}) \tag{35}$$

$$0 \leq S_m \leq M^{\sigma_m^-} (1 - \eta_m^{\sigma^-}) \tag{36}$$

$$0 \le \sigma_m^+ \le M^{\sigma_m^+}(\eta_m^{\sigma^+}) \tag{37}$$

$$0 \le S_m^{max} - S_m \le M^{\sigma_m^+}(1 - \eta_m^{\sigma^+}) \tag{38}$$

$$0 \le \delta_j^- \le M^{\delta_j}(\eta_j^{\delta^-}) \tag{39}$$

$$0 \le f_j^Q + Q_j^L \le M^{f_j^Q}(1 - \eta_j^{\delta^-}) \tag{40}$$

$$0 \le \delta_j^+ \le M^{\delta_j}(\eta_j^{\delta^+}) \tag{41}$$

$$0 \le f_j^Q - Q_j^L \le M^{f_j^Q}(1 - \eta_j^{\delta^+}) \tag{42}$$

$$\sum_n P_n^{inj} = 0 \tag{43}$$

$$\sum_{i \in N_{i,n}} P_i^{GC} + \sum_{i \in N_{e,n}} P_e^{GE} + P_n^{inj} = P_n^D \tag{44}$$

$$S_m - Q_m^D - c_e P_e^{GE} - c_i P_i^{GC} = \sum_{n \in N_{m,j}} Q_j^L \tag{45}$$

$$\sum_j Q_j^L = 0 \tag{46}$$

With binary expansion [24] and Fortuny-Amat linearization [20], variable P_i^{GC} can be discretized, and the nonlinear product $\xi_i \bar{P}_i^{GC}$ can be transferred to a linear expression (48) with constraints (49) and (50) as follows:

$$\bar{P}_i^{GC} = \Delta_{g_i} \sum_{k=0}^{\Lambda_i} 2^k y_{ki} \tag{47}$$

$$\xi_i \bar{P}_i^{GC} = \Delta_{g_i} \sum_{k=0}^{\Lambda_i} 2^k \hat{y}_{ki} \tag{48}$$

$$0 \le \xi_i - \hat{y}_{ki} \le M^{\xi_i}(1 - y_{ki}) \tag{49}$$

$$0 \le \hat{y}_{ki} \le M^{\xi_i} y_{ki} \tag{50}$$

Hence, the complex tri-level framework is rebuilt into a compact MILP model (A1–A56), which enables the accommodation of complex, large-scale systems with numerous decision variables.

3.2. Stage-2: Resilience Optimisation

In this stage, the planning options derived from Stage-1 are subjected to analysis under scenarios of low-probability but high-impact extreme events. This evaluation employs a deterministic approach, utilizing a resilience metric (RM) that quantifies the minimum load curtailment during the most severe scenarios as follows:

$$RM = \max_{z \in Z} \min_{(P,Q)} \sum_n F_n(P_n^{LC}) \le RM_{max} \tag{51}$$

Load curtailment alters the energy flow across gas pipelines and power lines. To streamline our analysis, we omit the impact on gas pipelines due to their resilience against extreme events compared to overhead power lines. The effects on power lines are encapsulated by the constraints below, which take into account the possibility of line outages during extreme events:

$$-f_l^P * (1 - z_l) \le \sum_{n \in N} \varphi_{l,n} P_n^{inj} \le f_l^P * (1 - z_l) \tag{52}$$

$$\sum_{i \in N_{i,n}} P_i^{GC} + \sum_{i \in N_{e,n}} P_e^{GE} + P_n^{inj} = P_n^D - P_n^{LC} \tag{53}$$

In addition, the number of out-of-service power lines due to extreme events is used to measure the impact of extreme events [6], and those failed lines are modeled within the following uncertainty set.

The significance of extreme events is gauged using the number of power lines that go out of service, modeled within the uncertainty set Z, where the confidence level k represents the duration, destructive path, and other characteristics and indicates the severity of extreme events.

$$Z = \{Z_{LC} | \sum_{LC} z_{LC} \le k\} \tag{54}$$

3.3. Problem Formulation and Solution

The two-stage optimization model is expressed mathematically as follows, with linear formulations accommodating generation costs and load curtailments. The model anticipates uncertain extreme events in Stage-1, then selects the worst-case scenarios based on the initial network configuration, and proposes responses to mitigate load curtailment Stage-2.

$$\begin{aligned} \min_{P^0,Q^0,f_j,f_l} \; & F^0(P^0, Q^0) \\ s.t. \; & A^0 P^0 + B^0 Q^0 \le C^0 u + D^0 f_l \\ & \max_{z} \min_{P,Q} F(P) \le RM_{max} \\ & AP + BQ \le Cu + Dz \end{aligned} \tag{55}$$

In the formulation, RM_{max} offers a mechanism for adjusting the resilience against critical loads proportionately to the total load, enhancing the model's robustness.

This can be solved with the column-and-constraint generation (CCG) method, which has been widely utilized to deal with robust optimization problems [25].

This two-stage max–min optimal problem (55) is tackled using the column-and-constraint generation (CCG) method, effectively addressing robust optimization [25]. The problem is bifurcated into a master problem and a sub-problem, as depicted in (56) and (57). The master problem provides a relaxed version of the original problem, while the sub-problem, focused on resilience metrics, integrates new worst-case scenarios into the model iteratively:

$$\begin{aligned} \min_{P^0,Q^0,f_j,f_l} \; & F^0(P^0, Q^0) \\ s.t. \; & A^0 P^0 + B^0 Q^0 \le C^0 f_j + D^0 f_l \\ & F(P^s) \le RM_{max} \\ & AP^s + BQ^s \le Cu + D\hat{z}^s \end{aligned} \tag{56}$$

$$\begin{aligned} \max_{z} \min_{P,Q} \; & F(P) \\ & AP + BQ \le C\hat{u}^s + Dz \end{aligned} \tag{57}$$

The iterative process, detailed in Algorithm 1, continues until the sub-problem's objective function falls below RM_{max}, ensuring that all resilience constraints are met.

Hence, the sub-problem can be transformed into a bilinear problem through the dualization of the inner minimization problem and then further reformulated as an MILP problem using the Big-M method. The master problem is an MILP problem as well. In this regard, these problems can both be solved with available commercial solvers like CPLEX [21].

Algorithm 1 Two-stage resilient planning.

Initialisation: Set the resilience metric $RM \leftarrow \infty$, iteration index $s = 0$, and extreme event scenario $\hat{z}^0 \leftarrow 0$.
while *not converged* **do**
  Solve the primary problem and determine the optimal expansion decisions.
  Solve the secondary problem and calculate the optimal solution $\hat{z}$ and update the related resilience metric RM.
  Build dispatch variables P^s and Q^s, as well as the associated operation constraints, on the basis of $\hat{z}$, and then substitute those variables and constraints into the primary problem.
  Update index $s \leftarrow s + 1$.
end while
return planning decisions

4. Case Studies

4.1. System Settings

In this section, we undertake a comprehensive analysis of the ISO New England power grid, modeled across eight zones, interconnected with a six-node natural gas system, including Maine (ME), Vermont (VT), New Hampshire (NH), NE Mass & Boston (NEMAB), WC Mass (WCMA), SE Mass (SEMA), Rhode Island (RI), and Connecticut (CT) [26]. The map of the system is shown in Figure 4. All eight zones contain electric demands, and all zones except for NEMAB are eligible with existing or candidate generation capacities.

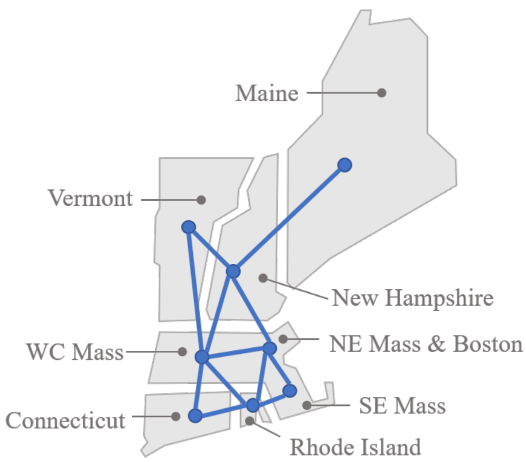

Figure 4. ISO New England system.

The case studies evaluate the interconnected system's response to various scenarios, including cost adjustments, capacity changes, and extreme event simulations, thereby highlighting the robustness and adaptability of our proposed planning approach.

The parameters of existing and candidate generic resources are adopted from [27]. It is assumed that each candidate's resource capacity can be expanded up to 1.5 GW. In addition, we assume that existing and candidate transmission capacities can be expanded up to 1.5 GW. An installation cost of USD 45 millionis imposed for the candidate lines. The network contains two natural gas sources, a large gas source connected to node 1 and a relatively small gas source linked to node 6. The existing capacity of the gas pipelines is adopted from [27]. Moreover, the gas pipeline can be expanded to a maximum capacity of 100,000 MBTU/h at an installation cost of USD 100,000 per MBTU/h. The investment cost is set according to [27]. The electric and non-generation-associated gas heat loads are adopted from [28,29] and are scaled on the basis of the assumed resource and natural gas pipeline capacities. A fixed natural gas price of USD 3 per MBTU is imposed for the whole system.

4.2. General Analysis

To analyze the impact of various costs on the planning results, we evaluate the following cases. Table 1 and Figures 5–8 show the results for all eight cases. For cost analysis, this indicates that lower investment costs are produced by lower-priced power system equipment. The natural gas pipeline investment cost has a significant impact on the total investment. Various equipment investment costs have no impact on the operation costs. For capacity analysis, lower candidate component capacities generally result in higher investment costs. However, in Case 7, with a different generation expansion strategy, a lower investment cost is achieved. The transmission line candidate capacities have no impact on the operating costs, whereas the natural gas pipeline candidate capacities and generation unit candidate capacities both have positive effects on the operating costs. In addition, lower costs are obtained using the proposed method, even with a higher contingency level. The eight cases are as follows:

- Case 1 (Benchmark): the data summarized in Section 4.1 were used to form the benchmark case.
- Case 2: the investment costs of a natural gas pipeline capacity expansion are set 50% lower than in Case 1.
- Case 3: the investment costs of a resource capacity expansion are set 50% higher than in Case 1.
- Case 4: the investment costs of a transmission line capacity expansion are set 50% higher than in Case 1.
- Case 5: the installed capacities of the candidate natural gas pipelines are set 10% lower than in Case 1.
- Case 6: the installed capacities of the candidate generation units are set 20% higher than in Case 1.
- Case 7: the installed capacities of the candidate transmission lines are set 20% lower than in Case 1.
- Case 8: in Stage-1, the simulated loss of transmission lines is reduced by 66%.

Figure 6 lists the generation unit investment decisions. In the cost analysis, there is no difference between Cases 2, 3, and 4. For the capacity analysis, only Cases 5 and 6 have different investment capacities, both of which are higher than in the other cases, i.e., 4000 MW. The higher cost is caused by lower natural gas pipeline candidate capacities or higher generation unit candidate capacities.

Figure 7 summarizes the investment in the transmission system. For the cost analysis, various equipment prices have no impact on the expansion of the transmission network. For the capacity analysis, the various natural gas pipeline candidate capacities and generation unit candidate capacities lead to different expansion strategies.

Figure 8 depicts the investment in natural gas pipeline capacity expansions. A lower candidate capacity results in a lower installed capacity, whereas lower-priced pipelines lead to the installation of more gas pipelines. Moreover, using the proposed method, the load curtailment is reduced from 8688 MW to 7587 MW for the same level of extreme event.

Table 1. Optimal costs for all cases.

	Objective Function Value [USD Billion]	Investment Cost [USD Billion]	Operating Cost [USD Million]
Case 1	30.167	30.166	1.343
Case 2	17.189	17.188	1.343
Case 3	32.217	32.216	1.343
Case 4	30.222	30.22	1.343
Case 5	30.276	30.275	1.283
Case 6	28.352	28.351	1.383
Case 7	29.367	29.366	1.343
Case 8	30.305	30.304	1.303

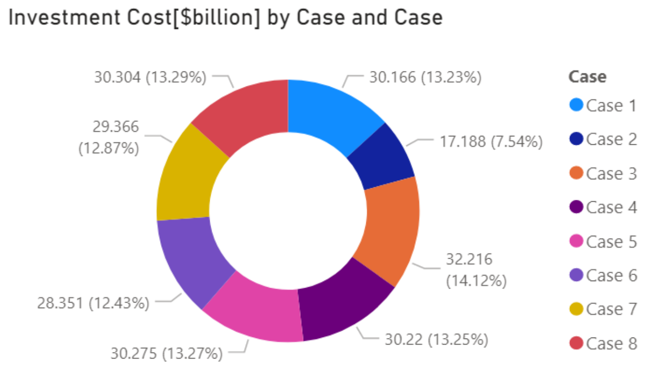

Figure 5. Optimal objective function values for all cases.

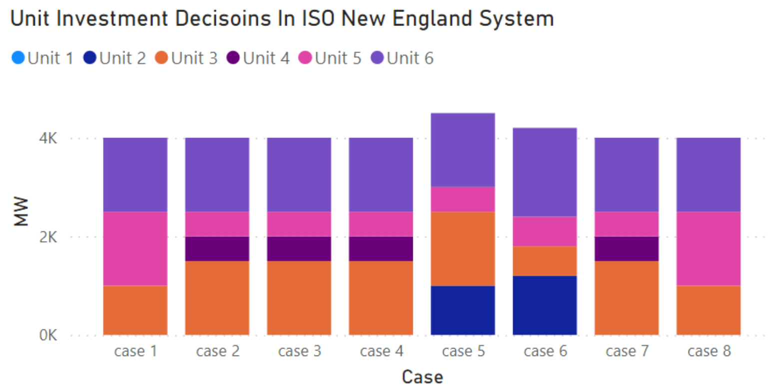

Figure 6. Unit investment decisions in ISO New England system.

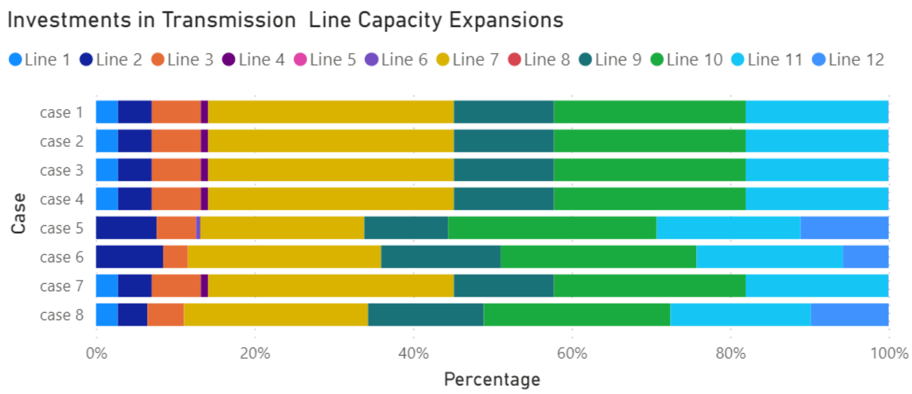

Figure 7. Investments in transmission line capacity expansions.

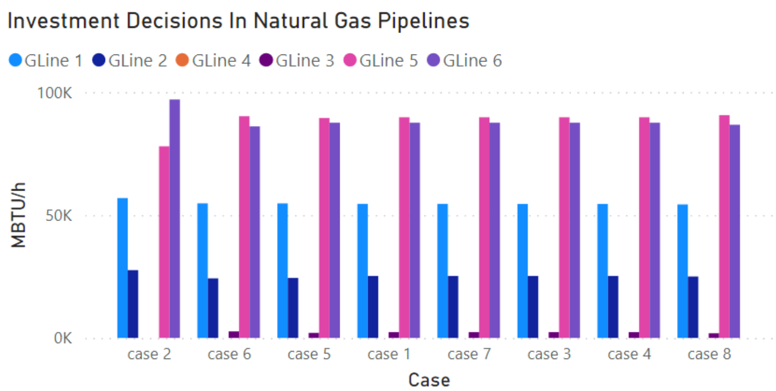

Figure 8. Investment decisions in natural gas pipelines.

4.3. Cost Sensitivity Analysis

Our findings reveal that adjustments in investment costs directly influence the overall planning outcomes. Notably, a reduction in natural gas pipeline expansion costs (Case 2) significantly decreases the total investment required, underscoring the substantial financial impact of pipeline infrastructure on regional energy systems. Conversely, increases in the costs associated with resource and transmission line expansions (Cases 3 and 4) slightly elevate the total project costs.

4.4. Capacity Sensitivity Analysis

Adjusting the capacities of candidate components yields insightful trends; notably, reducing natural gas pipeline capacities (Case 5) leads to marginally higher investment costs, reflecting the critical role of gas infrastructure in ensuring system resilience. On the other hand, enhancing generation unit capacities (Case 6) or reducing transmission line capacities (Case 7) influences both investment and operational costs, highlighting the intricate balance between generation, transmission, and demand in maintaining system efficiency.

4.5. Load Curtailment Sensitivity

The reduction in simulated transmission line losses (Case 8) further validates the resilience of our planning approach. By effectively managing infrastructure vulnerabilities, our model demonstrates a capacity to mitigate the impacts of severe disruptions, ensuring reliable energy delivery even under stringent conditions.

4.6. Operational Implications and Strategic Insights

The diverse investment decisions across generation units, transmission systems, and gas pipeline expansions, as visualized in Figures 6–8, encapsulate the strategic nuances inherent in our planning model. Specifically, the model's adaptability to various pricing and capacity scenarios illustrates its potential to guide strategic investment decisions, ensuring that infrastructure development aligns with regional energy needs and resilience objectives.

Moreover, the resilience optimization stage plays a pivotal role in enhancing system robustness against extreme events. By quantifying the minimum load curtailment achievable under severe conditions, our model not only informs infrastructure investment decisions but also contributes to the strategic planning necessary to withstand unforeseen disruptions.

5. Conclusions

In conclusion, this paper emphasizes the vital importance of integrating pipeline planning within the broader strategy for enhancing utility resilience. Underground pipelines, which are less affected by extreme weather events compared to overhead power lines, provide a sturdy solution for maintaining electricity supply during adverse conditions.

We developed a two-stage model to strengthen the combined resilience of electricity and natural gas systems. This approach, practical through the use of mixed-integer programming, was designed to meet current planning needs while being adaptable for future changes. The insights from our case studies on cost, capacity, and load curtailment illustrate the model's ability to navigate the intricacies of modern energy systems effectively, offering valuable strategies for utilities to ensure economic efficiency alongside resilience to extreme events.

Future work will focus on incorporating renewable energy and adjusting to evolving market dynamics, enhancing our model's readiness for a renewable-powered future.

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Nomenclature

Indices	
e	Index of existing generation units.
i	Index of candidate generation units.
j	Index of natural gas pipelines.
l	Index of transmission lines.
m	Index of natural gas system nodes.
n	Index of power system buses.
G	Index of generation companies.
Sets	
N^{inv}	Set of candidate generation units.
N^{fix}	Set of fixed generation units.
$L^{P,inv}$	Set of candidate transmission lines.
$L^{Q,inv}$	Set of candidate gas pipelines.
Constants	
a_i, b_i	Parameters of the candidate generation operational cost function of unit i.
g_i^0	Generation capacity of unit i available before *Level-2*.
K_i	Annual unit cost of investment in capacity expansion for candidate generation unit i.
K_j	Annual unit cost of investment in capacity expansion for gas pipeline j.
K_l	Annual unit cost of investment in capacity expansion for transmission line l.
$f_l^{P,0}, f_l^{P,max}$	Initial/maximum capacity of transmission line l.
$f_j^{Q,0}, f_j^{Q,max}$	Initial/maximum capacity of gas pipeline j.
M	Large constant.
$\varphi_{l,n}$	Power transfer distribution factor associated with line l with respect to unit injection/withdrawal at bus n.
Δ_{g_i}	Size of the step used to discretize generation capacity i.
P_n^D	Inelastic demand at bus n.
Λ_i	Parameter used to the discretize generation capacity g_i expansion associated with the number of binary variables. The total number of binary variables is $\Lambda_i + 1$.
Variables	
f_l^P	Thermal capacity limit of transmission line after decisions have been made at *Level-1*. This remains constant for *Level-2* and *Level-3*.
f_j^Q	Capacity limit of gas pipeline after decisions have been made at *Level-1*. This remains constant for *Level-2* and *Level-3*.
g_i	Generation capacity available at node after decisions have been made at *Level*-2.
P_e^{GE}	Power generated by existing generation units.
P_i^{GC}	Power generated by candidate generation units.
P_n^{inj}	Import/export power from/to bus i.
S_m	Natural gas extracted from node m.
Q_j^L	Natural gas flow through pipeline j.
$\bar{P}_i^{GC,EQ}$	Expansion equilibrium strategies for all GENCOs.
$\bar{P}_i^{GC}$	Each equilibrium strategy renders more revenue than any other one.
$\bar{P}_{-i}^{GC,EQ}$	Other GENCOs are considered constants in their equilibrium strategies.
Dual Variables	
α	Dual variable related to constraint P_n^{inj}.
β	Dual variable related to the nodal natural gas flow balance constraint.
λ_l^-, λ_l^+	Dual variable of the thermal capacity bounds of transmission line l.
δ_j^-, δ_j^+	Dual variable of the capacity bounds of gas pipeline j.

γ_e^-, γ_e^+	Dual variable of the operating range for existing unit e.
μ_m	Dual variable of the gas balance equation at node m.
π_n	Locational marginal price reflecting the dual variable of the electricity balance equation at bus n.
σ_m^-, σ_m^+	Dual variable of the production capacity for gas source m.
ξ_i^-, ξ_i^+	Dual variable of the production operating range for candidate resource i.
Ancillary Variables	
η	Binary variables from the Fortuny-Amat linearization at *Level-3*.
y_{ki}	Binary variable that is equal to 1 if the kth step of the discretization of g_i is considered and is equal to 0 otherwise.
$\hat{y}_{ki}$	Product of ξ^+ by y_{ki}.
$\tilde{y}_{ki}$	Product of P_i^{GC} by y_{ki}.

Appendix A

We present the complete model of the transmission planning formulated as an MILP problem subject to the EPEC-MILP and market equilibrium constraints:

$$\begin{aligned}\min_{f_l^P, f_j^Q} \sum_{i \in N^{inv}} & \left[a_i (P_i^{GE,E} + P_i^{GC,E}) - b_i (\Delta_{g_i} \sum_{k=0}^{\Lambda_i} 2^k \tilde{y}_{ki}^E) \right] \\ & + \sum_{i \in N^{fix}} a_i P_i^{GE,E} + \sum_{i \in N^{inv}} K_i (\Delta_{g_i} \sum_{k=0}^{\Lambda_i} 2^k y_{ki}^E) \\ & + \sum_{l \in L^{inv}} K_l (f_l^P - f_l^{P,0}) + \sum_{j \in J^{inv}} K_j (f_j^Q - f_j^{Q,0})\end{aligned} \tag{A1}$$

subject to

$$f_l^{P,0} \le f_l^P \le f_l^{P,max} \tag{A2}$$

$$f_j^{Q,0} \le f_j^Q \le f_j^{Q,max} \tag{A3}$$

$$0 \le P_i^{GC,E} - \tilde{y}_{ki}^E \le M^{g_i} (1 - y_{ki}^E) \tag{A4}$$

$$0 \le \tilde{y}_{ki}^E \le M^{g_i} y_{ki}^E \tag{A5}$$

Equilibrium and Profit Definition

$$U_G^E \ge U_G^S \tag{A6}$$

$$\begin{aligned}U_G^E = & \sum_e P_e^{GE,max} \gamma_e^{+,E} + \sum_{i \in N_G^{inv}} \Bigg\{ (P_i^{GC,max} \xi_i^{+,E} + \\ & \Delta_{g_i} \sum_{k=0}^{\Lambda_i} 2^k \hat{y}_{ki}^E) - K_i (\Delta_{g_i} \sum_{k=0}^{\Lambda_i} 2^k y_{ki}^E) \Bigg\}\end{aligned} \tag{A7}$$

$$\begin{aligned}U_G^S = & \sum_e P_e^{GE,max} \gamma_e^{+,S} + \sum_{i \in N_G^{inv}} \Bigg\{ (P_i^{GC,max} \xi_i^{+,S} + \\ & \Delta_{g_i} \sum_{k=0}^{\Lambda_i} 2^k \hat{y}_{ki}^S) - K_i (\Delta_{g_i} \sum_{k=0}^{\Lambda_i} 2^k y_{ki}^S) \Bigg\}\end{aligned} \tag{A8}$$

Left-Hand-Side Constraints

$$a_e - \pi_n^E - \gamma_e^{-,E} + \gamma_e^{+,E} + c_e \mu_e^E = 0 \tag{A9}$$

$$\begin{aligned}& a_i - b_i (\Delta_{g_i} \sum_{k=0}^{\Lambda_i} 2^k y_{ki}^E) - \pi_n^E \\ & - \xi_i^{-,E} + \xi_i^{+,E} + c_i \mu_i^E = 0\end{aligned} \tag{A10}$$

$$\alpha^{E} - \pi_n^{E} + \sum_{l \in L} (\lambda_l^{+,E} - \lambda_l^{-,E}) \varphi_{l,n} = 0 \tag{A11}$$

$$-\mu_m^{E} - \sigma_m^{-,E} + \sigma_m^{+,E} = 0 \tag{A12}$$

$$\mu_m^{E} + \beta^{E} - \delta_j^{-,E} + \delta_j^{+,E} = 0 \tag{A13}$$

$$0 \le \xi_i^{-,E} \le M^{\xi_i^{-,E}} (\eta_i^{\xi^{-,E}}) \tag{A14}$$

$$0 \le P_i^{GC,E} \le M^{\xi_i^{-,E}} (1 - \eta_i^{\xi^{-,E}}) \tag{A15}$$

$$0 \le \xi_i^{+,E} \le M^{\xi_i^{+,E}} (\eta_i^{\xi^{+,E}}) \tag{A16}$$

$$0 \le \Delta_{g_i} \sum_{k=0}^{\Lambda_i} 2^k y_{ki}^{E} - P_i^{GC,E} \le M^{\xi_i^{+,E}} (1 - \eta_i^{\xi^{+,E}}) \tag{A17}$$

$$0 \le \gamma_e^{-,E} \le M^{\gamma_e^{-,E}} (\eta_e^{\gamma^{-,E}}) \tag{A18}$$

$$0 \le P_e^{GE,E} \le M^{\gamma_e^{-,E}} (1 - \eta_e^{\gamma^{-,E}}) \tag{A19}$$

$$0 \le \gamma_e^{+,E} \le M^{\gamma_e^{+,E}} (\eta_e^{\gamma^{+,E}}) \tag{A20}$$

$$0 \le P_e^{GE,max} - P_e^{GE,E} \le M^{\gamma_e^{+,E}} (1 - \eta_e^{\gamma^{+,E}}) \tag{A21}$$

$$0 \le \lambda_l^{-,E} \le M^{\lambda_l} (\eta_l^{\lambda^{-,E}}) \tag{A22}$$

$$0 \le f_l^{P} + \sum_{n \in N} \varphi_{l,n} P_n^{inj,E} \le M^{f_l^{P}} (1 - \eta_l^{\lambda^{-,E}}) \tag{A23}$$

$$0 \le \lambda_l^{+,E} \le M^{\lambda_l} (\eta_l^{\lambda^{+,E}}) \tag{A24}$$

$$0 \le f_l^{P} - \sum_{n \in N} \varphi_{l,n} P_n^{inj,E} \le M^{f_l^{P}} (1 - \eta_l^{\lambda^{+,E}}) \tag{A25}$$

$$0 \le \sigma_m^{-,E} \le M^{\sigma_m^{-,E}} (\eta_m^{\sigma^{-,E}}) \tag{A26}$$

$$0 \le S_m \le M^{\sigma_m^{-,E}} (1 - \eta_m^{\sigma^{-,E}}) \tag{A27}$$

$$0 \le \sigma_m^{+,E} \le M^{\sigma_m^{+,E}} (\eta_m^{\sigma^{+,E}}) \tag{A28}$$

$$0 \le S_m^{max} - S_m \le M^{\sigma_m^{+,E}} (1 - \eta_m^{\sigma^{+,E}}) \tag{A29}$$

$$0 \le \delta_j^{-,E} \le M^{\delta_j} (\eta_j^{\delta^{-,E}}) \tag{A30}$$

$$0 \le f_j^{Q} + Q_j^{L} \le M^{f_j^{Q}} (1 - \eta_j^{\delta^{-,E}}) \tag{A31}$$

$$0 \le \delta_j^{+,E} \le M^{\delta_j} (\eta_j^{\delta^{+,E}}) \tag{A32}$$

$$0 \le f_j^{Q} - Q_j^{L} \le M^{f_j^{Q}} (1 - \eta_j^{\delta^{+,E}}) \tag{A33}$$

$$0 \le \xi_i^{+,E} - \hat{y}_{ki}^{E} \le M^{\xi_i^{+}} (1 - y_{ki}^{E}) \tag{A34}$$

$$0 \le \hat{y}_{ki}^{E} \le M^{\xi_i^{+}} y_{ki}^{E} \tag{A35}$$

$$\sum_{n} P_n^{inj,E} = 0 \tag{A36}$$

$$\sum_{i \in N_{i,n}} P_i^{GC,E} + \sum_{i \in N_{e,n}} P_e^{GE,E} + P_n^{inj,E} = P_n^{D} \tag{A37}$$

$$S_m^{E} - Q_m^{D} - c_e P_e^{GE,E} - c_i P_i^{GC,E} = \sum_{n \in N_{m,j}} Q_j^{L,E} \tag{A38}$$

$$\sum_{j} Q_j^{L,E} = 0 \tag{A39}$$

Right -Hand-Side Constraints

$$a_e - \pi_n^S - \gamma_e^{-,S} + \gamma_e^{+,S} + c_e\mu_e^S = 0 \tag{A40}$$

$$a_i - b_i(\bar{P}_i^{GC.S}) - \pi_n^S - \xi_i^{-,S} + \xi_i^{+,S} + c_i\mu_i^S = 0 \tag{A41}$$

$$\begin{aligned} &a_{-i} - b_{-i}(\Delta_{g_{-i}} \sum_{k=0}^{\Lambda_{-i}} 2^k y_{k_{-i}}^E) - \pi_n^S \\ &- \xi_{-i}^{-,S} + \xi_{-i}^{+,S} + c_{-i}\mu_{-i}^S = 0 \end{aligned} \tag{A42}$$

$$\alpha^S - \pi_n^S + \sum_{l\in L}(\lambda_l^{+,S} - \lambda_l^{-S})\varphi_{l,n} = 0 \tag{A43}$$

$$\mu_m^S - \sigma_m^{-,S} + \sigma_m^{+,S} = 0 \tag{A44}$$

$$\mu_m^S + \beta^S - \delta_j^{-,S} + \delta_j^{+,S} = 0 \tag{A45}$$

$$0 \le \xi_i^{-,S} \le M^{\xi_i^{-,S}}(\eta_i^{\xi^{-,S}}) \tag{A46}$$

$$0 \le P_i^{GC,S} \le M^{\xi_i^{-,S}}(1 - \eta_i^{\xi^{-,S}}) \tag{A47}$$

$$0 \le \xi_i^{+,S} \le M^{\xi_i^{+,S}}(\eta_i^{\xi^{+,S}}) \tag{A48}$$

$$0 \le \Delta_{g_i} \sum_{k=0}^{\Lambda_i} 2^k y_{ki}^E - P_i^{GC,S} \le M^{\xi_i^{+,S}}(1 - \eta_i^{\xi^{+,S}}) \tag{A49}$$

$$0 \le \gamma_e^{-,S} \le M^{\gamma_e^{-,S}}(\eta_e^{\gamma^{-,S}}) \tag{A50}$$

$$0 \le P_e^{GE,S} \le M^{\gamma_e^{-,S}}(1 - \eta_e^{\gamma^{-,S}}) \tag{A51}$$

$$0 \le \gamma_e^{+,S} \le M^{\gamma_e^{+,S}}(\eta_e^{\gamma^{+,S}}) \tag{A52}$$

$$0 \le P_e^{GE,max} - P_e^{GE,S} \le M^{\gamma_e^{+,S}}(1 - \eta_e^{\gamma^{+,S}}) \tag{A53}$$

$$0 \le \lambda_l^{-,S} \le M^{\lambda_l}(\eta_l^{\lambda^{-,S}}) \tag{A54}$$

$$0 \le f_l^P + \sum_{n\in N}\varphi_{l,n}P_n^{inj,S} \le M^{f_l^P}(1 - \eta_l^{\lambda^{-,S}}) \tag{A55}$$

$$0 \le \lambda_l^{+,EQ} \le M^{\lambda_l}(\eta_l^{\lambda^{+,S}}) \tag{A56}$$

$$0 \le f_l^P - \sum_{n\in N}\varphi_{l,n}P_n^{inj,S} \le M^{f_l^P}(1 - \eta_l^{\lambda^{+,S}}) \tag{A57}$$

$$0 \le \sigma_m^{-,S} \le M^{\sigma_m^{-,S}}(\eta_m^{\sigma^{-,S}}) \tag{A58}$$

$$0 \le S_m \le M^{\sigma_m^{-,S}}(1 - \eta_m^{\sigma^{-,S}}) \tag{A59}$$

$$0 \le \sigma_m^{+,S} \le M^{\sigma_m^{+,S}}(\eta_m^{\sigma^{+,S}}) \tag{A60}$$

$$0 \le S_m^{max} - S_m \le M^{\sigma_m^{+,S}}(1 - \eta_m^{\sigma^{+,S}}) \tag{A61}$$

$$0 \le \delta_j^{-,S} \le M^{\delta_j}(\eta_j^{\delta^{-,S}}) \tag{A62}$$

$$0 \le f_j^{Q,S} + Q_j^{L,S} \le M^{f_j^Q}(1 - \eta_j^{\delta^{-,S}}) \tag{A63}$$

$$0 \le \delta_j^{+,S} \le M^{\delta_j}(\eta_j^{\delta^{+,S}}) \tag{A64}$$

$$0 \le f_j^{Q,S} - Q_j^{L,S} \le M^{f_j^Q}(1 - \eta_j^{\delta^{+,S}}) \tag{A65}$$

$$0 \le \xi_{-i}^{+,S} - \hat{y}_{k-i}^S \le M^{\xi_{-i}^{+}}(1 - y_{k-i}^E) \tag{A66}$$

$$0 \le \hat{y}_{k-i}^S \le M^{\xi_{-i}^{+}} y_{k-i}^E \tag{A67}$$

$$\sum_n P_n^{inj,S} = 0 \tag{A68}$$

$$\sum_{i \in N_{i,n}} P_i^{GC,S} + \sum_{i \in N_{e,n}} P_e^{GE,S} + P_n^{inj,S} = P_n^D \tag{A69}$$

$$S_m^S - Q_m^D - c_e P_e^{GE,S} - c_i P_i^{GC,S} = \sum_{n \in N_{m,j}} Q_j^{L,S} \tag{A70}$$

$$\sum_j Q_j^{L,S} = 0 \tag{A71}$$

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