# MAE 573 Term Project

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# 1 Introduction

As the U.S. electricity system advances toward a net-zero future, a significant increase in the deployment of weather-dependent renewable energy resources is anticipated. While this grid transformation holds positive environmental, economic and climate promises, ensuring grid reliability amidst the transition remains paramount, particularly during peak demand periods. In recent years, the U.S. electric power sector has faced considerable reliability challenges, such as forced outages due to the unreliability of gas supply for dispatchable resources critical to grid reliability. Notable incidents include the 2014 Polar Vortex [10] and the Texas power crisis of February 2021 [11], underscoring the vulnerabilities in the current U.S. energy infrastructure. This is raising public concern over grid reliability. In fact, companies like Dominion Energy have recognized the urgency of this issue and are currently implementing measures to guarantee power supply reliability during high-demand winter seasons using onsite Liquefied Natural Gas (LNG) storage [9]. As a key mitigation strategy, the deployment onsite gas storage allows power plants to procure and store essential fuel for meeting generation needs during periods of gas scarcity.

The aim of this project is to explore the impact of onsite gas storage deployment on the fixed and variable costs of thermal power plants, determine the optimal storage capacity required by each facility, and devise effective scheduling strategies. The analysis spanned three storage options: natural gas, the transitional and predominant fuel for U.S. gas-fired plants particularly in New England; hydrogen; and oil storage, viewed as a last-resort alternative. The findings indicate an uptick in fixed costs with the introduction of storage across all scenarios, coupled with disparities in storage volumes and potential land usage across different options. Hydrogen emerged as the costliest due to higher capital expenditures, attributed to technological and infrastructural factors, whereas oil storage, initially the least expensive, incurred significant additional costs when dual combustion retrofitting expenses were factored in. Notably, for natural gas plants without dual oil combustion capabilities, options such as natural gas or hydrogen storage present more cost-effective alternatives. Furthermore, the study examined variations in total variable costs associated with the fuel used for storage, revealing that green hydrogen incurred the relatively higher variable costs, followed by natural gas and then oil, which remained a more economical choice. This reveals the need for technological innovation and policy support to double down on efforts geared towards reducing cost premiums associated with clean energy technologies.

Employing the GenX Electricity System planning model, developed collaboratively by the Zero-carbon Energy Systems Research and Optimization (ZERO) Lab at Princeton University and MIT Energy Initiative, the model was refined to integrate updates addressing storage deployment's fixed costs, variable costs and associated storage constraints. These adjustments ensured that the storage solutions met both energy generation and reserve requirements for the thermal power plant(s). The test bed for this model was the single-zone Small New England system, adjusted for unit commitment and reserve obligations, containing a sole dispatchable thermal power resource alongside variable renewable energy sources and battery storage. Despite the system's simplicity, the insights garnered provide a valuable understanding of the grid's behavior under various onsite gas storage scenarios.

# 2 Methods

## 2.1 GenX Electricity System Planning Model

The optimization model employed for this study is GenX, an advanced open-source electricity system optimization model jointly developed by Princeton University's ZERO Lab and the Massachusetts Institute of Technology (MIT) Energy Initiative. GenX evaluates net-zero scenarios for electricity systems with high degrees of temporal and spatial resolutions. It has proven highly effective in modelling net-zero scenarios with dispatchable thermal resources, and significant penetration of renewable energy resources like wind and solar, as well as fast-burst resources like batteries. As an open-source tool, GenX is accessible to a wide range of researchers, industry stakeholders and policymakers, for continuous improvement and adaptation, enhancing its credibility and robustness for detailed net-zero energy systems planning and policy analysis. These properties make GenX a suitable modelling candidate for this project.

## 2.2 Project Model Formulation

For this study, an onsite gas storage module was developed within the GenX model. The module extends the core functionalities of GenX by incorporating additional variables, cost expressions, and constraints relevant to modeling onsite gas storage. GenX is equipped with various test systems that serve as a basis for deriving modeling insights. For the purposes of our project, we utilized the SmallNewEngland System—a straightforward setup that includes a single dispatchable resource, one solar resource, one wind resource, and a battery storage system. While efforts are ongoing to evaluate the updated model on larger and more complex systems, the SmallNewEngland System proves to be adequately robust for yielding insights that are valuable to this project's objectives. Subsequent sections share more on the model's design and implementation.

## 2.3 Model Integration with GenX

On GenX, an onsite_gas_storage!() function integrates an onsite gas storage module into the optimization model EP. It adds variables, expressions, and constraints related to onsite gas storage to the energy production model EP, utilizing input data and configuration parameters from inputs and setup dictionaries.

## 2.4 Model Variables

In the model developed for assessing onsite gas storage in gas-fired power plants, several variables are defined to capture various aspects of storage and power generation. The Storage Capacity (vStorageCap) represents the required storage capacity for each resource in MMBtu, while the Storage Charge (vStorageCharge) and Storage Discharge (vStorageDischarge) track the hourly amount of gas stored and discharged, respectively, in MMBtu. The State of Storage (vStateOfStorage) provides a dynamic measurement of the gas amount in storage at each hour. The fixed and variable costs of storage are captured through eCStorage_fixed[y] for individual resources and eTotalCStorage_fixed for all resources, along with eCStorage_var[y, t] and eTotalCStorage_var which mirror these costs on a variable basis. The energy output of each resource is quantified in MWh through EP[vP], and the reserve requirements are tracked by EP[vRSV][y, t]. The model also includes the gas reliability factor (g_GR), which ranges from 0 to 1 to indicate gas supply reliability each hour, the heat rate (heat_rate[y]) for each resource's efficiency, and a dataframe (dfGen) containing data of all generators. Additionally, the set of all gas-fired power plants (GAS_PLANTS) and the total number of time steps (T) representing 8,760 hours in a year, are integral to the model, providing a holistic framework for analyzing the interplay between storage, costs, and power generation efficiency.

## 2.5 Objective Function

The objective function includes fixed and variable costs associated with different types of gas storage (CNG, oil, hydrogen).

### 2.5.1 Fixed Cost Expression:

The fixed costs associated with onsite gas storage for each gas-fired resource $y$ are calculated as follows:

- For CNG Storage:

$$\begin{aligned} eCStorage\_fixed[y] = {} & dfGen[y, \text{Fixed\_CNG\_Storage\_Cost\_per\_MMBTUyr}] \\ & + dfGen[y, \text{Fixed\_CNG\_Compressor\_Cost\_per\_MMBtuyr}] \\ & \times vStorageCap[y] \end{aligned}$$

- For Oil Storage:

$$\begin{aligned} eCStorage\_fixed[y] = {} & dfGen[y, \text{Fixed\_Oil\_Storage\_Cost\_per\_MMBTUyr}] \\ & \times vStorageCap[y] \quad + dfGen[y, \text{Fixed\_Dual\_Oil\_Combustor\_Cost\_per\_MWyr}] \\ & \times EP[vCAP][y] \end{aligned}$$

- For Hydrogen Storage:

$$\begin{aligned} eCStorage\_fixed[y] = {} & dfGen[y, \text{Fixed\_Hydrogen\_Storage\_Cost\_per\_MMBTUyr}] \\ & + dfGen[y, \text{Fixed\_Hydrogen\_Compressor\_Cost\_per\_MMBtuyr}] \\ & \times vStorageCap[y] \end{aligned}$$

The total onsite gas storage fixed costs are the sum of the individual resource contributions:

$$eTotalCStorage\_fixed = \sum(eCStorage\_fixed[y] \text{ for } y \text{ in } GAS\_PLANTS)$$

### 2.5.2 Variable Cost Expression:

The variable costs of onsite storage for charging during each hour $t$ for resource $y$ are determined by the fuel cost:

- For CNG Storage:

$$eCStorage\_var[y, t] = (C\_Fuel\_per\_MWh[y, t]/heat\_rate[y]) \times vStorageCharge[y, t]$$

- For Oil Storage:

$$eCStorage\_var[y,t] = Oil\_Fuel\_Cost\_per\_MMBtu \times vStorageCharge[y,t]$$

- For Hydrogen Storage:

$$eCStorage\_var[y,t] = Green\_Hydrogen\_Fuel\_Cost\_per\_MMBtu \times vStorageCharge[y,t]$$

The total variable charging costs are the sum of the individual resource contributions for all time steps $T$:

$$eTotalCStorage\_var = \sum(eCStorage\_var[y,t] \text{ for } y \text{ in } GAS\_PLANTS \text{ for all } T)$$

### 2.6 Mathematical Expressions for Constraints

1. **State of Storage Constraint**
   Ensures continuity in the storage level for each gas-fired resource $y$ at each time $t$:

   $$vStateOfStorage[y,t] = vStateOfStorage[y,t-1] + vStorageCharge[y,t] - vStorageDischarge[y,t]$$

2. **Conditional Storage Discharge Constraint**
   Regulates storage discharge based on the hourly gas reliability factor $g\_GR$ for each resource $y$ and time $t$:

   $$vStorageDischarge[y,t] = (1 - g\_GR[y,t]) \times EP[vP][y,t] \times heat\_rate[y]$$

3. **Minimum State of Storage Constraint**
   Ensures the storage level meets discharge and reserve requirements for each resource $y$ and time $t$:

   $$vStateOfStorage[y,t] \geq vStorageDischarge[y,t] + EP[vRSV][y,t] \times heat\_rate[y]$$

4. **Maximum State of Storage Constraint**
   Ensures the storage level does not exceed the built storage capacity for each resource $y$ and time $t$:

   $$vStateOfStorage[y,t] \leq vStorageCap[y]$$

5. **Maximum Storage Charge Rate Constraint**
   Limits the charge rate for storage depending on the type of storage for each resource $y$ and time $t$:

   $$vStorageCharge[y,t] \leq dfGen[y, \text{'Storage\_Max\_Charge\_Rate'}] \times g\_GR[y,t]$$

## 3 Data Sources

### 3.1 Generator Parameters and Costs

In the analysis of the SmallNewEngland system, comprehensive datasets for generators were readily accessible within GenX. These included the hourly energy demand for the zone, hourly capacity factors for variable renewable resources, and parameters for generators such as heat rate, fixed and variable costs, and relevant operational sets. Additionally, unit commitment parameters—encompassing minimum up and down times, as well as ramp rates—were also pre-integrated on GenX.

## 3.2 Storage Equipment Costs

A comprehensive review of various sources was conducted to ascertain the cost parameters essential for running the model. The fixed cost parameters—including the costs of CNG storage tanks, compressors for CNG storage, oil storage tanks, and the installation of dual combustion capabilities in natural gas plants—were sourced from [1]. Given that most natural gas-fired power plants are progressively adapted to combust hydrogen [2] and considering that hydrogen combustion is intended only for periods when gas supply is unreliable, it was assumed that no supplementary cost for dual combustion retrofitting for hydrogen would be necessary. The literature presents a wide range of compressor costs for hydrogen [3]; however, the cost of hydrogen compressors was considered the same as that of CNG compressors since they fall within the same cost spectrum. The costs for hydrogen compressors and the dual retrofitting for oil storage obtained from [1] were annualized based on a 30-year lifespan for the power plant assets, incorporating the Weighted Average Cost of Capital (WACC) of 0.035 or Capital Recovery Factor (CRF) of 0.0544 obtained from GenX.

The resource [1] offers detailed fixed and equipment costs for CNG and oil across three scenarios: low, medium, and high. For this study, we elected to consider only the median values from the medium scenario, as the study's outcomes rely on markedly conservative data, suggesting that the actual costs may be lower than those reported. For the fixed cost data for compressed hydrogen storage tanks, the U.S. Department of Energy (DOE) base case of $383/kgH2 was employed [4].

## 3.3 Fuel Costs and Maximum Charging Rate Parameters

CNG fuel costs were obtained from the existing hourly natural gas price data within the GenX database. The costs for green hydrogen were obtained from [5]. The maximum filling rates for the CNG storage tanks were based on standards from fast-fill CNG stations, as reported in industry references [7]. Given the analogous nature of their storage processes, the same filling rate assumptions for CNG was applied to compressed hydrogen storage. For oil storage rates, the U.S EPA limit of 6-10gpm of petroleum discharge [8] was incorporated.

## 3.4 Gas Reliability Factors

The gas reliability factors were calibrated to mirror periods of heightened demand. As detailed in [1], gas unreliability within the ISO NE region is predominantly observed during the winter and spring months. Nonetheless, incidents of gas scarcity are known to extend throughout the year. To assign precise gas reliability factors to each hourly segment, the 8,760 hours under consideration were categorized into the four meteorological seasons: winter, spring, summer, and fall. Utilizing demand data sourced from GenX, hours where demand surpassed 90% of the seasonal peak were allocated a gas reliability factor of 0. Conversely, all remaining hours received a gas reliability factor of 1. This stratagem ensures that the model's storage solutions are equipped to alleviate potential shortages throughout the year. The cumulative count of critical hours—designated by a gas reliability factor of 0—totals approximately 136 hours, equating to around 5.667 days for each storage system, which may be deemed conservative. For context, Dominion Energy is planning for a 4-day storage capacity for each of their two major plants. Table 1 summarizes relevant parameters employed for the study.

Table 1: Important Onsite Storage Model Parameters

| **Relevant Model Parameters** | **Parameter Value** |
|---|---|
| Fixed CNG Compressor Cost per MMBtuyr | 3808.00 |
| CNG Storage Max Charge Rate MMBtu per hr | 49.40 |
| Fixed Oil Storage Cost per MMBTUyr | 13.77 |
| Fixed Dual Oil Combustor Cost per MWyr | 2938.00 |
| Oil Storage Max Charge Rate MMBtu per hr | 52.00 |
| Oil Fuel Cost per MMBtu | 27.00 |
| Fixed Hydrogen Storage Cost per MMBTUyr | 3372.81 |
| Fixed Hydrogen Compressor Cost per MMBtuyr | 3808.00 |
| Hydrogen Storage Max Charge Rate MMBtu per hr | 49.40 |
| Green Hydrogen Fuel Cost per MMBtu | 48.43 |

# 4 Results

## 4.1 Fixed Costs

The deployment of on-site storage results in only a slight increase in the total system fixed costs, as illustrated in Figure 1. This minimal rise is attributed to the relatively low cost of storage when compared to the fixed costs of the power plant itself. However, the inclusion of retrofitting costs, as demonstrated with oil storage, leads to a significant escalation in fixed costs. This increase is primarily because the fixed costs associated with installing dual combustion capabilities are proportional to the plant's capacity, rather than the storage capacity required. In the case of hydrogen storage, dual combustion costs were not considered, given that new gas turbines are increasingly being built with capabilities for hydrogen combustion [2]. Therefore, when considering on-site storage for natural gas-fired power plants, where the installation of dual combustion capability is a factor, opting for on-site hydrogen or natural gas storage presents more economical alternatives.

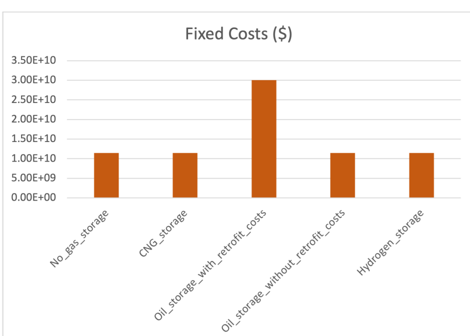


Figure 1: System fixed costs across difference storage scenarios

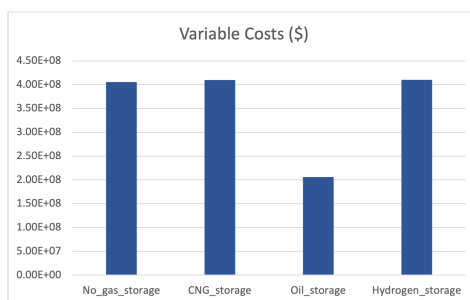


Figure 2: Variable costs across different storage scenarios

## 4.2 Variable Costs

Similar to fixed costs, only marginal changes are noted in the total system variable costs, as depicted in Figure 2. This is primarily because only a limited number of storage hours are required annually. For this project, each gas-fired facility needs storage for only 136 hours out of the total 8,760 hours in a year. Consequently, any changes in variable costs are specific to the hours when an alternative combustion fuel is used, while the overall system's variable costs are affected only minimally. Among the three scenarios examined, oil storage demonstrates the most significant reduction in variable costs. This decrease is directly linked to the current relative affordability of oil compared to natural gas and hydrogen fuels. The most considerable increase in variable costs was observed with green hydrogen, followed by natural gas, and then oil. However, the advantages of lower variable costs with oil could be offset by the expenses incurred from retrofitting for dual combustion. Furthermore, the negative environmental impacts of using fossil fuels, combined with the escalating oil prices exacerbated by the Russia-Ukraine conflict, render oil storage an unsustainable option.

## 4.3 Optimal Storage Scheduling

A significant finding from the study relates to the optimal scheduling of storage, as integrated into the constraints for each scenario. The model, along with its constraints, is strategically designed to ensure the lowest possible fuel consumption while constructing adequate storage capacity. This approach adheres to all pertinent storage constraints, including discharging during periods of gas unreliability and maintaining a minimum reserve in each hour.

For instance, considering a typical case of CNG storage, Figure 3 illustrates the state of storage (i.e., the amount of gas in storage), along with storage discharge and charge in each hour. Notably, storage discharge is predominantly zero for most hours, occurring only during select periods when the gas reliability factor drops to zero. Furthermore, it is observed that storage charging (indicating when excess CNG is purchased and stored) primarily takes place during the summer months of June, July and August (hours 3500 to 6000), attributed to the lower costs of CNG fuels in these periods.

These insights into scheduling are invaluable for plant operators who aim to balance supply reliability with cost minimization. Similar patterns in scheduling are observed across other storage scenarios as well.

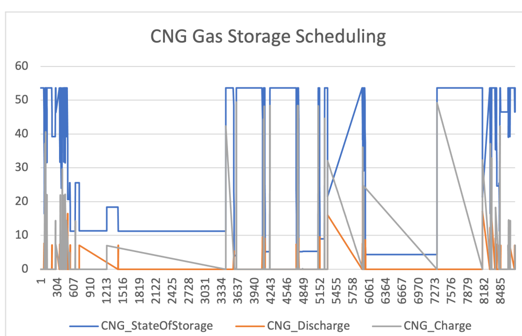


Figure 3: Optimal storage scheduling for CNG storage

## 4.4 Optimal Built Storage Capacities

Figure 4 illustrates the relationship between the optimal storage capacity required for each scenario. While the model results indicate a uniform storage requirement in MMBtu for each resource, the actual volume of storage necessary varies due to the differing densities of the fuels. Oil, being the densest, necessitates the smallest volume of storage, followed by CNG, and then hydrogen. These variations in density are likely to have significant implications on land requirements for each type of storage. Consequently, the land area required for oil storage is anticipated to be approximately five times less than that for CNG storage and six times less than that for hydrogen storage, as depicted in Figure 4.

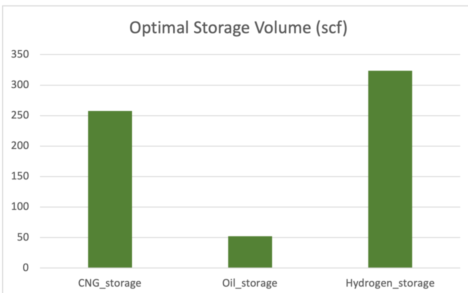


Figure 4: System fixed costs across difference storage scenarios

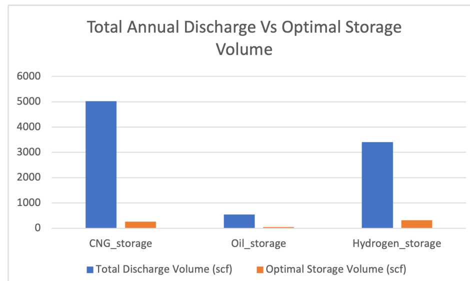


Figure 5: Variable costs across different storage scenarios

## 4.5 Total Annual Discharge vs. Optimal Storage Volume

In this study, the optimality of the storage capacities determined by the model was also investigated. By calculating the total annual discharge from each storage facility, the efficiency of the built capacities can be assessed. Suppose the storage facilities were designed to hold the entire year's fuel requirement at the start of the year, discharging it as needed. In that case, Figure 5 reveals that CNG would necessitate 20 times more storage, oil would require 5 times more, and hydrogen would demand 10 times more storage capacity. This underscores the crucial role of optimal storage scheduling in minimizing both the required storage capacity and overall system costs.

# 5 Discussion

In addressing the U.S. electricity system's transition towards a net-zero future, this project, utilizing the GenX Electricity System planning model, focused on the pivotal role of onsite gas storage in enhancing grid reliability, particularly during peak demand periods. The study's findings, set against the backdrop of significant reliability challenges like the 2014 Polar Vortex and the 2021 Texas power crisis, reveal that while introducing storage solutions—encompassing natural gas, hydrogen, and oil—marginally increases fixed costs, it is crucial for ensuring grid stability. Notably, the fixed and variable costs analysis, show green hydrogen as the most expensive, followed by natural gas and oil, with the latter emerging as a cost-effective but environmentally unsustainable option. Where dual combustion retrofitting is required, the results also show that oil storage is less economical compare to hydrogen and natural gas storage options. The study also highlights the importance of storage volume optimization and land use efficiency, especially considering the density differences among fuels and their subsequent land requirements. Furthermore, optimal storage capacity and scheduling are underscored as vital for minimizing storage needs and costs, aligning with initiatives like Dominion Energy's use of LNG storage for winter demand. These insights offer a comprehensive understanding of the economic and environmental implications of storage deployment, guiding the energy sector towards sustainable, reliable, and cost-effective solutions in the face of an evolving energy landscape and climate change.

The findings of this study, while providing valuable insights, also point towards the need for further research to obtain a more comprehensive and realistic understanding of the U.S. electricity grid under distributed onsite gas storage configuration. A key limitation lies in the simplicity of the modeled system, which primarily included a single dispatchable thermal power resource. To enhance the applicability of these insights, future studies should consider a system with a broader deployment of gas-fired power plants, reflecting more complex and varied grid scenarios. Additionally, the practicality of using Compressed Natural Gas (CNG) and compressed hydrogen for power plants, given their volumetric limitations, emerges as a significant concern. Real-world applications often require large volumes of fuel, rendering CNG and compressed hydrogen less feasible due to their high storage requirements and related logistical challenges. Future modeling efforts should pivot towards exploring the use of Liquefied Natural Gas (LNG) and potentially liquid hydrogen. These liquid fuels, capable of being transported in larger quantities and regasified onsite, present a more practical solution for meeting the high fuel demands of power plants. Incorporating parameters and costs associated with LNG and liquid hydrogen would provide a more accurate representation of potential storage solutions, thereby offering more realistic and actionable insights for decision-makers in the energy sector.

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# 6 Appendix

For more information on the model's formulation on GenX, the onsite gas storage module can be accessed via a fork of the GenX GitHub repository, available here.

## 6.1 Variables

In the model, new variables were defined for onsite gas storage:

1. Storage Capacity ($vStorageCap$): Represents the required storage capacity by each gas-fired resource in MMBtu.
2. Storage Charge ($vStorageCharge$): Amount of gas purchased and stored by each resource per hour in MMBtu.
3. Storage Discharge ($vStorageDischarge$): Amount of gas or oil discharged from onsite storage of each resource per hour in MMBtu.
4. State of Storage ($vStateOfStorage$): The amount of gas in onsite storage for each resource at each hour in MMBtu.
5. $eCStorage\_fixed[y]$: Fixed cost of storage for each gas-fired resource.
6. $eTotalCStorage\_fixed$: Total fixed cost of storage for all gas-fired resources.
7. $eCStorage\_var[y, t]$: Variable cost of storage for each gas-fired resource.
8. $eTotalCStorage\_var$: Total variable cost of storage for all gas-fired resources.
9. $EP[vP]$: Energy Generated by each resource in MWh.
10. $EP[vRSV][y, t]$: Reserve requirement of each gas-fired resource in each hour.
11. $g\_GR$: Gas reliability factor, which ranges between 1 and 0 and indicates the reliability of gas supply in each hour. A $g\_GR$ of 1 indicates reliable gas supply. A $g\_GR$ of 0 indicates gas supply unreliability.
12. heat_rate[y]: heat rate of each gas-fired resource.
13. dfGen: Dataframe containing data of all generators.
14. GAS_PLANTS: Set of all gas-fired power plants.
15. T: Total number of time steps, 8760.