Hydrogen Supply Chain Planning with Flexible Transmission and Storage Scheduling

Guannan He, Dharik S. Mallapragada, Abhishek Bose, Clara F. Heuberger, and Emre Gençer

Abstract—Hydrogen is becoming an increasingly appealing energy carrier, as the costs of renewable energy generation and water electrolysis continue to decline. Developing modelling and decision tools for the H₂ supply chain that fully capture the flexibility of various resources is essential to understanding the overall cost-competitiveness of H₂ use. To address this need, we have developed a H₂ supply chain planning model that determines the least-cost mix of H₂ generation, storage, transmission, and compression facilities to meet H₂ demands and is coupled with power systems through electricity prices. We incorporate flexible scheduling for H₂ trucks and pipeline, allowing them to serve as both H₂ transmission and storage resources to shift H₂ demand/production across space and time. The case study results in the U.S. Northeast indicate that the proposed framework for flexible scheduling of H₂ transmission and storage resources is critical not only to cost minimization but also to the choice of H₂ production pathways between electrolyzer and centralized natural-gas-based production facilities. Trucks as mobile storage could make electrolyzer more competitive by providing extra spatiotemporal flexibility to respond to the electricity price variability while meeting H₂ demands. The proposed model also provides a reasonable trade-off between modeling accuracy and computational time.

Index Terms—Hydrogen supply chain planning, electrolytic hydrogen production, mobile storage, flexibility

NOMENCLATURE

Indices and Sets

- \( i, \, I \): Index and set of H₂ pipelines options in the network
- \( j, \, J \): Index and set of H₂ truck resources
- \( k, \, K \): Index and set of H₂ generation resources
- \( s, \, S \): Index and set of H₂ storage resources
- \( t, \, \tau \): Index of time intervals
- \( z, \, z' \): Index of zones in the network
- \( z \rightarrow z' \): Index of paths for H₂ transport
- \( B \): Set of paths for H₂ transport
- \( T \): Set of time intervals
- \( Z \): Set of zones in the network
- \( E \): Superscript for empty truck
- \( F \): Superscript for full truck
- \( CHA \): Superscript for charging
- \( DIS \): Superscript for discharging
- \( c \): Superscript for capital cost
- \( e \): Superscript for electricity consumption

Parameters

- \( t_0 \): Time origin
- \( \Delta t \): Time resolution (hour)
- \( \delta_{ij} \): Annuity factor for various resources
- \( c^*_{\text{GEN}} \): Unit capital cost of H₂ generation unit \( k \) ($/(tonne-H₂/hour))
- \( \lambda^*_{\text{ELE}} \): Electricity price at zone \( z \) and time \( t \) ($/MWh)
- \( \lambda^*_{\text{GAS}} \): Natural gas price at zone \( z \) and time \( t \) ($/MMBtu)
- \( \eta^*_{\text{ELE}} \): Electricity consumption rate per unit H₂ production resource \( k \) at zone \( z \) ($/MWh/tonne-H₂$)
- \( \eta^*_{\text{GAS}} \): Natural gas consumption rate per unit H₂ production resource \( k \) at zone \( z \) ($/MMBtu/tonne-H₂$)
- \( M^*_{\text{GEN}} \): The rated production capacity of a H₂ generation unit for resource \( k \) at zone \( z \) (tonne-H₂/hour)
- \( c^*_{\text{TRU}} \): Unit capital cost of H₂ storage \( s \) ($/tonne-H₂$)
- \( c^*_{\text{TRU}} \): Unit capital cost of truck \( j \) ($/unit$)
- \( c^*_{\text{TRU}} \): Unit operational cost of truck \( j \) ($/mile$)
- \( \bar{E}_j \): Capacity of truck technology \( j \) (tonne-H₂)
- \( \sigma_j \): H₂ boil-off loss of truck technology \( j \)
- \( \Delta_{z,z'} \): Travel time delay of trucks between zone \( z \) and \( z' \)
- \( e^*_{\text{GEN}} \): Unit emission rate of H₂ generation resource \( k \) (tonne-CO₂/tonne-H₂)
- \( e^*_{\text{TRU}} \): Emission rate of truck \( j \) (tonne-CO₂/(tonne-H₂-mile))
- \( c^*_{\text{LOS}} \): Unit value of lost H₂ load ($/(tonne/hour)$)
- \( \alpha^e_j, \, \alpha^f_j \): Unit capital cost and electricity consumption of compression facilities proportional to pipeline length for pipeline type \( i \) ($/mile$, MWh/tonne-H₂-mile)
- \( \beta^e_j, \, \beta^f_j \): Unit capital cost and electricity consumption of compression facilities not related to pipeline length for pipeline type \( i \) ($, MWh/tonne-H₂$)
- \( \Gamma^e_j, \, \Gamma^f_j \): Unit capital cost and electricity consumption of compression/liquefaction facilities for truck type \( j \) ($/(tonne-H₂/hour)$, MWh/tonne-H₂)
- \( \Phi^e_j, \, \Phi^f_j \): Unit capital cost and electricity consumption of compression facilities for storage type \( s \) ($/(tonne-H₂/hour)$, MWh/tonne-H₂)
- \( D_{z,t} \): H₂ demand at zone \( z \) time \( t \) (tonne-H₂/hour)
- \( \Omega_t \): Annual scaling factor for time \( t \)
- \( c^*_{\text{EMI}} \): Carbon emission price ($/tonne$)

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**Variables**

\[ h_{\text{GEN}}^{k,z,t} \]  
H₂ produced by resource \( k \) at zone \( z \) during time \( t \) (tonne/hour)

\[ h_{\text{TRA}}^{z,t} \]  
H₂ transport to zone \( z \) during time \( t \) (tonne/hour)

\[ h_{\text{COM}}^{s} \]  
Natural gas used by resource \( k \) to produce H₂ at zone \( z \) during time \( t \) (MMBtu/hour)

\[ N_{k,z} \]  
Number of available units of resource \( k \) at zone \( z \)

\[ V_{s}^{\text{STO}} \]  
Capacity of H₂ storage resource \( s \) at zone \( z \) (tonne)

\[ H_{s}^{\text{STO}} \]  
Maximum charge/discharge rate of H₂ storage resource \( s \) at zone \( z \) (tonne/hour)

\[ I_{\text{PIP},i}^{j,z,z',t} \]  
Number of pipeline type \( i \) between \( z \) and \( z' \)

\[ h_{\text{PIP}}^{z,z',t} \]  
H₂ exchange at zone \( z \) via pipeline \( i \) between \( z' \) and \( z \) during time \( t \) (tonne/hour). PIP+ is the superscript for delivered H₂, and PIP- for drawn H₂

\[ p_{c,t}^{z} \]  
Power consumption by compression facilities at zone \( z \) during time \( t \) (MW)

\[ H_{\text{TRU}}^{j,z,t} \]  
Maximum compression liquefaction capacity of truck station type \( j \) at zone \( z \) (tonne/hour)

\[ V_{j}^{t} \]  
Number of full or empty trucks of type \( j \) at time \( t \)

\[ u_{j}^{t} \]  
Total number of invested trucks of type \( j \)

\[ x_{j}^{t} \]  
Number of full or empty trucks of type \( j \) in transit from \( z \) to \( z' \) at time \( t \)

\[ y_{j}^{t} \]  
Number of full or empty trucks of type \( j \) departing from \( z \) to \( z' \) at time \( t \)

\[ q_{j}^{t} \]  
Number of full, charged, discharged trucks of type \( j \) at time \( t \)

I. Introduction

Deep decarbonization of the energy system is contingent on identifying pathways for eliminating greenhouse gas (GHG) emissions from not only the power sector but also other end-use sectors where direct electrification may be challenging [1]. In this context, identifying cost-effective pathways for supplying energy carriers like hydrogen remains an appealing prospect [2]. Recent renewed interest in hydrogen has been spurred, in part, by expectations on cost declines for water electrolyzers [3], which raises the prospect of electrolytic hydrogen produced from variable renewable energy (VRE) resources becoming cost-competitive with fossil-fuel-based pathways such as steam methane reforming (SMR) [4]. However, hydrogen production represents only a fraction of the total cost of hydrogen supply for distributed end uses like transportation, owing to the relatively high cost associated with transmission, storage, and distribution [5]. Therefore, identification of cost-effective hydrogen supply chains (HSC) requires a careful consideration of all stages of the supply chain, including production, transport, storage and end-use, as well as their inter-dependencies.

Some existing studies have investigated hydrogen as a basic storage system (with co-located electrolyzer, fuel cell, and gas tank) while not as a network that consists of various production, transmission and storage infrastructures as well as hydrogen demand. The coordination schemes of hydrogen storage with wind farms are studied in [6], [7]. The scheduling and energy trading strategies of hydrogen storage in wholesale or local energy markets are studied in [8], [9]. These studies revealed the potential role and benefit of hydrogen storage in power systems, while they did not explore the economic competitiveness of power-to-hydrogen technologies nor inform the investment needed in HSC infrastructures for hydrogen use in power and other end-use sectors.

In the literature on HSC planning, many opportunities for further modeling improvements exist. First, few HSC models account for the variability in electricity supply and its impact on the least-cost infrastructure planning. With the prospect of electrolytic hydrogen supply, there is a need to incorporate the arising spatiotemporal variations in electricity supply (and prices) resulting from increasing VRE penetrations in the power systems [10], [11]. Second, most existing literature on HSC planning adopt a limited set of hydrogen transmission pathways, ignoring pipeline [12]–[16], gas truck [16], and/or liquid truck [14] options. Some also ignore critical hydrogen production options including electrolyzer [13] and SMR with or without carbon capture and storage (CCS) [12], [14], [17]–[19], even though the mode of hydrogen production (electrolyzer versus SMR) is a critical determining factor to the cost-competitive transmission mode (gas/liquid truck versus pipeline). Third, most literature use over-simplified models for hydrogen transmission via truck transport. For example, the truck transportation is modelled with fixed lower and upper flow limits for each route in [13]–[15], [18]–[20]. In reality, traveling delay is inevitable for road transport, and a truck can serve different routes and sites both as transmission and storage assets. The availability of trucks is also likely to vary over space and time, and assuming the hydrogen flow limits are time- and route-invariant will underestimate either the required capital costs or the flexibility of trucks. To the best of our knowledge, there has not been a full-fledged HSC model that incorporates all critical technological options in hydrogen production, transmission, and storage while also accounting for their spatiotemporal operational flexibility.

This paper develops a high-fidelity HSC model to evaluate the cost-competitiveness of hydrogen for decarbonizing various end-uses and the trade-offs between various technology options across the HSC. The main contributions of this paper are summarized as follows:

1) We propose an HSC planning model that determines the least-cost technology mix across the supply chain based on its operation under spatiotemporal variations in electricity inputs and hydrogen demands.

2) We explicitly model the flexibility of a wide range of conventional and emerging hydrogen-related technologies, including electrolyzer, SMR with and without CCS, pressure vessel and geological storage, hydrogen transport via liquid and gaseous modes in trucks, gaseous mode via pipeline, and associated compression/liquefaction facilities.

3) The framework incorporates a flexible scheduling and routing model for hydrogen trucks to serve as both transmission and mobile storage, which shift hydrogen demand/production in space and time while being shared across
the whole hydrogen network. We also develop a scheduling model for pipeline operation that considers the ability of pipeline to function as storage via an approximation of line packing. While the HSC planning model with flexible truck scheduling is complex in nature, we made the model computationally tractable using judicious approximations at little cost of modelling accuracy.

4) We apply the HSC planning model to study the future hydrogen infrastructure needs under various carbon policy and hydrogen demand scenarios in the U.S. Northeast, based on electricity price profiles generated from a power system capacity expansion model. We demonstrate the value of the proposed sophisticated scheduling models and analyze the trade-offs and synergies between different technologies given their investment and operational flexibility.

The remainder of this paper is organized as follows. Section II introduces the flexibility characteristics of various transmission and storage technologies across the HSC. Section III formulates the HSC planning model in detail. Section IV describes the case studies and the results of the HSC planning model for various technology and policy scenarios. The conclusions are drawn in Section V.

II. Flexibility of Storage and Transmission Technologies in Hydrogen Supply Chain

H\textsubscript{2} storage resources, both stationary and mobile storage either in geological formations and pressure vessels, enable shifting production in space and time to better match supply and demand. Among stationary storage, we focus on physical H\textsubscript{2} storage technologies, namely pressure vessel H\textsubscript{2} storage and geological H\textsubscript{2} storage, which are the most mature technologies to store H\textsubscript{2} today [21].

Geological H\textsubscript{2} storage is based on storing thousands of tonnes of compressed H\textsubscript{2} in geological formations like salt caverns and aquifers. The limited geographic availability of these formations and perceived safety issues, however, may limit their use. Pressure vessel H\textsubscript{2} storage, unlike geological storage, does not depend on geographical resources and thus can be deployed in a modular and spatially flexible manner. The cost of pressure vessel H\textsubscript{2} storage at pressures of 350-500 bar is low compared to electrochemical energy storage, typically ranging from $15-20/kWh-H\textsubscript{2} [21]–[23]. Cushion gas is required to maintain the pressure and withdraw rate of geologic storage, typically ranging from 30-50% of the total storage volume, depending on the geological formation type [24].

Among mobile H\textsubscript{2} storage options, compressed H\textsubscript{2} trucks, or namely gas trucks, carry pressure vessels (bundles of H\textsubscript{2} tubes) with hydrogen usually compressed at 180 bar, much lower than the pressure vessel stationary storage (and hence lower carrying weight). Due to the pressure limit imposed by road transport regulations, the hydrogen carrying capacity of a gas truck is limited to 0.3-0.6 tonne (10-17 MWh\textsubscript{t}) [22], [25]. The advantage of gas trucks over pressure vessel H\textsubscript{2} storage is that it can travel and be shared across the whole HSC to provide on-demand storage service and meet spatio-temporally varying energy supply and demand. Liquid trucks carry cryogenic vessels with liquid hydrogen (lower than 33 K). The hydrogen carrying capacity of commercially available liquid truck is typically 4 tonnes (133 MWh\textsubscript{t}) [22], [25], significantly greater than gas trucks owing to higher volumetric energy density of liquid hydrogen. Liquefaction, however, requires much higher energy consumption and capital costs than gas compression (approximately 11 MWh/tonne vs. 1 MWh/tonne [22]). Liquid trucks also have higher boil-off rates and thus are not a preferred solution for long-duration storage but may be more suitable for long-distance transport.

While pipelines are usually built for large-volume transmission, it can also function as storage, through line packing. Hydrogen can be either withdrawn from or injected to the pipeline terminals like storage discharging or charging. A pipeline with 8-inch diameter and 100 bar can store approximately 0.3 tonne hydrogen per mile, approximately 20% of the energy content of natural gas that can be stored in a similar natural gas pipeline per mile [26].

III. Hydrogen Supply Chain Planning Model

Here we present the model framework for identifying the least-cost H\textsubscript{2} infrastructure, spanning production, transmission and storage, needed to meet given spatio-temporal H\textsubscript{2} demand and energy (electricity, natural gas) prices. The schematic of the HSC including various components and energy flows are shown in Figure 1. The interactions between the HSC and the power grid are modeled assuming that the HSC is a price-taker, which implies that electricity price profiles at a given location are not impacted by electricity consumption from the HSC at that location. The decision variables are the capacities/numbers of units for H\textsubscript{2} production, storage, compression, and transmission resources, as well as the hourly operational schedules of the resources. They are continuous except the truck scheduling variables.

A. Objective function

The total cost associated with H\textsubscript{2} infrastructure includes the capital and operating cost of the four main elements of the supply chain, production, storage, compression and transmission (as in (1)). This includes the capital costs of: H\textsubscript{2} production units ($C_{GEN}$) as in (2), H\textsubscript{2} storage ($C_{STO}$) as in (3), H\textsubscript{2} pipeline ($C_{PIP}$) as in (4), trucks for H\textsubscript{2} transport ($C_{TRU}$) as in (5), and H\textsubscript{2} compression facilities ($C_{COM}$) associated with pipeline ($C_{COM,PIP}$), truck station ($C_{COM,TRU}$), and storage
The main operating costs included in the objective function are: electricity cost ($C_{\text{ELE}}$) as in (7), natural gas, cost for H₂ production ($C_{\text{GAS}}$) as in (9), operating costs for H₂ truck transport ($C_{\text{TRU}}$) as in (10), emission costs from H₂ production and truck transport ($C_{\text{EMI}}$) as in (11), and costs of lost load ($C_{\text{LOS}}$) as in (12).

$$\min \quad C_{\text{GEN}} + C_{\text{STO}} + C_{\text{PIP}} + C_{\text{TRU}} + C_{\text{COM}} + C_{\text{ELE}} + C_{\text{GAS}} + C_{\text{TRU}} + C_{\text{EMI}} + C_{\text{LOS}}$$

$$C_{\text{GEN}} = \delta \sum_{k \in K} \sum_{z \in Z} \sum_{t \in T} h_{kz}^{\text{NEW}}$$

$$C_{\text{STO}} = \delta \sum_{s \in S} \sum_{z \in Z} \sum_{t \in T} h_{sz}^{\text{VSTO}}$$

$$C_{\text{PIP}} = \delta \sum_{i \in I} \sum_{z \in Z} \sum_{t \in T} h_{zii}^{\text{LPP}} I_{z \rightarrow z', i, t}$$

$$C_{\text{TRU}} = \delta \sum_{j \in J} \sum_{z \in Z} \sum_{t \in T} h_{jz}^{\text{TRU}} V_{j}$$

$$C_{\text{COM}} = \delta \sum_{k \in K} \sum_{z \in Z} \sum_{t \in T} \left( \alpha_{z}^{2} L_{z \rightarrow z', i, t} + \beta_{z}^{2} \right)$$

$$C_{\text{ELE}} = \delta \sum_{z \in Z} \sum_{t \in T} \gamma_{z}^{\text{TRU}} + \sum_{z \in Z} \sum_{t \in T} \phi h_{z}^{\text{STO}}$$

$$C_{\text{GAS}} = \delta \sum_{k \in K} \sum_{z \in Z} \sum_{t \in T} \left( \eta_{kz}^{\text{ELE}} h_{kz}^{\text{GEN}} + \phi_{kz}^{\text{COM}} \right)$$

$$C_{\text{TRU}} = \delta \sum_{j \in J} \sum_{z \in Z} \sum_{t \in T} \left( \eta_{jz}^{\text{TRU}} \right)$$

$$C_{\text{EMI}} = \delta \sum_{k \in K} \sum_{z \in Z} \sum_{t \in T} \left( \phi \right)$$

$$C_{\text{LOS}} = \delta \sum_{z \in Z} \sum_{t \in T} \left( \right)$$

### C. Hydrogen Production Constraints

The outputs of each type of H₂ generation facilities have to be kept within their lower and upper bounds ($R_{kz}^{\text{GEN}}$ and $R_{kz}^{\text{utton}}$), as in (14). $M_{kz}^{\text{GEN}}$ is the rated size of a H₂ generation unit. $n_{kz,t}$ denotes the number of online units. The number of online units have to be less than the number of generation units as in (15).

$$n_{kz,t} \leq N_{kz}$$

The number of units starting up and shutting down, represented by $n_{kz,t}^{\text{UP}}$ and $n_{kz,t}^{\text{DOWN}}$, are modelled in (16). There are limits on the period of time between when a unit starts up and when it can be shut-down again, and vice versa, modelled in (17) and (18). The minimum up and down time are denoted by $t_{kz}^{\text{up}}$ and $t_{kz}^{\text{down}}$, respectively.

$$n_{kz,t} \geq \sum_{\tau = t \pm t_{kz}^{\text{up}}}^{t_{kz}^{\text{down}}} n_{kz,t}^{\text{UP}}$$

$$n_{kz,t} - n_{kz,t-1} \geq n_{kz,t}^{\text{UP}} - n_{kz,t-1}^{\text{DOWN}}$$

### D. Hydrogen Storage Constraints

The cumulative H₂ in storage should be kept under its maximum capacity and above a volume for cushion gas requirement, as follows:

$$V_{sz}^{\text{STO}} \geq \sum_{t \in T} \left( h_{sz}^{\text{CHU}} \eta_{sz}^{\text{STO}} - h_{sz}^{\text{DIS}} \right) \Delta t \geq R_{sz}^{\text{STO}} V_{sz}^{\text{STO}}$$

where $V_{sz}^{\text{STO}}$ is the available storage capacity; $\eta_{sz}^{\text{STO}}$ is the charging and discharging efficiency (typically 100% for H₂ storage); and $R_{sz}^{\text{STO}}$ denotes the minimum ratio of stored H₂ to the maximum capacity. The charging rate of H₂ storage is physically capped by compression capability, as follows:

$$h_{sz}^{\text{CHU}} \geq H_{sz}^{\text{CHU}} \geq 0 \quad \forall z \in Z, s \in S, t \in T$$

### E. Hydrogen Transmission Constraints

1) **Balance:** The total amount of H₂ transport between two zones is equal to the sum of the amounts through pipeline and truck. $h_{z \rightarrow z', i, t}^{\text{PP}}$ represents that H₂ is delivered to zone z through the pipeline i between zone z and z' during time t. Positive $h_{z \rightarrow z', i, t}^{\text{PP}}$ represents that H₂ is delivered to zone z, while negative value represents that H₂ flows out from zone z. $h_{z \rightarrow z', j, t}^{\text{TRU}}$ denotes the H₂ exchange of the truck type j at zone z during time t. Positive $h_{z \rightarrow z', j, t}^{\text{TRU}}$ represents that the truck is discharging H₂ to zone z, while negative value represents that the truck is charging H₂ from zone z.

$$h_{z \rightarrow z', i, t}^{\text{PP}} = \sum_{z \in Z} \sum_{t \in T} h_{z \rightarrow z', i, t}^{\text{PP}} + \sum_{j \in J} h_{z \rightarrow z', j, t}^{\text{TRU}}$$

$$\forall z \in Z, t \in T$$
2) Pipeline: The H\textsubscript{2} exchange at zone \(z\) through the pipeline \(i\) between zone \(z\) and \(z'\) can be split into the H\textsubscript{2} delivery (\(h_{\text{PIP}}^{z,z'}\)) and the H\textsubscript{2} flowing out (\(h_{\text{PIP}}^{z',z}\)), as follows:

\[
h_{\text{PIP}}^{z,z'} = h_{\text{PIP}}^{z,z'} - h_{\text{PIP}}^{z',z} \quad \forall z \to z' \in B, i \in I, t \in T \quad (22)
\]

The flow rate of H\textsubscript{2} through pipeline type \(i\) is capped by the operational limits of the pipeline \(i\), \(E_i\), multiplied by the number of constructed pipeline \(i\) (\(l_{z-z'}\)), as follows:

\[
E_i l_{z-z'} \geq - \sum_{\tau=0}^{t} (h_{\text{PIP}}^{z,z',\tau} + h_{\text{PIP}}^{z',z,\tau}) \Delta t_i \geq \frac{1}{2} \sum_{\tau=0}^{t} (h_{\text{PIP}}^{z,z',\tau} + h_{\text{PIP}}^{z',z,\tau}) \Delta t_i \\
\forall z' \in Z, z \in Z, i \in I, t \in T \quad (24)
\]

where the maximum amount of H\textsubscript{2} that can be stored in pipeline is denoted by \(E_i\), and the minimum amount, typically 0, is denoted by \(R_{\text{PIP}}^{z,z'}\).

3) Truck: We incorporate a flexible truck scheduling and routing model, which accurately captures the travelling delay of trucks and allows trucks to be shared across different routes and zones. We denote full and empty trucks with different sets of variables. Within each set, the state of trucks are further categorized into trucks in inventory at each zone and trucks in transit between each pair of zones, the latter category including departing, traveling, and arriving trucks. The schematic of the truck scheduling model is shown in Figure 2. While the number of trucks are integer in nature, we relax them to continuous variables to improve the computational tractability. In the case studies, we validate that this approximation is at little cost of modelling and decision accuracy.

The sum of full and empty trucks should equal the total number of invested trucks, as (25). The full (empty) trucks include full (empty) trucks in transit and staying at each zones, as (26):

\[
\begin{align*}
V_j^F &= \sum_{z-z'} \sum_{\tau=0}^{t} u_{z-z',\tau,j}^F + \sum_{z} q_{z,j}^F \quad \forall j \in J, t \in T \quad (25) \\
V_j^E &= \sum_{z-z'} \sum_{\tau=0}^{t} u_{z-z',\tau,j}^E + \sum_{z} q_{z,j}^E \quad \forall j \in J, t \in T \quad (26)
\end{align*}
\]

The change of the total number of full (empty) available trucks at zone \(z\) should equal the number of charged (discharged) trucks minus the number of discharged (charged) trucks at zone \(z\) plus the number of full (empty) trucks that just arrived minus the number of full (empty) trucks that just departed:

\[
\begin{align*}
q_{z,j}^{E,F} - q_{z,j}^{E,F} &= u_{z-z',\tau,j}^F - u_{z,z',\tau,j}^E + \sum_{z} (x_{z,z',j}^{F,E} - x_{z,z',j}^{E,F}) \\
\forall z \in Z, j \in J, t \in T
\end{align*}
\]

The number of full (empty) trucks in transit from zone \(z\) to zone \(z'\) should equal the number of full (empty) trucks that just departed from zone \(z\) minus the number of full (empty) trucks that just arrived at zone \(z'\):

\[
\begin{align*}
\sum_{\tau=0}^{t} \left( u_{z-z',\tau,j}^E - x_{z,z',\tau,j}^{E,F} - x_{z,z',\tau-1,j}^{E,F} \right) &= \sum_{\tau=0}^{t} \left( x_{z,z',\tau,j}^{E,F} - u_{z-z',\tau,j}^E - x_{z,z',\tau-1,j}^{E,F} \right) \\
\forall z \to z' \in B, j \in J, t \in T
\end{align*}
\]

The minimum travelling time delay is modelled in (29)-(30). The number of full (empty) trucks in transit from \(z\) to \(z'\) at time \(t\) should be greater than the number of full (empty) truck departing \(z\) between time \(t - \Delta_{z-z'} + 1\) and \(t\), as follows:

\[
\begin{align*}
\sum_{\tau=0}^{t} x_{z-z',\tau,j}^{E,F} &= \sum_{\tau=0}^{t} \left( x_{z-z',\tau,j}^{E,F} - x_{z-z',\tau-1,j}^{E,F} - x_{z-z',\tau-1,j}^{E,F} \right) \\
\forall z \to z' \in B, j \in J, t \in T
\end{align*}
\]

The number of full (empty) trucks in transit from \(z\) to \(z'\) at time \(t\) should be greater than the number of full (empty) trucks arriving at \(z'\) from between time \(t + 1\) and \(t + \Delta_{z-z'}\), as follows:

\[
\begin{align*}
\sum_{\tau=0}^{t} x_{z-z',\tau,j}^{E,F} + \sum_{\tau=0}^{t} x_{z-z',\tau,j}^{E,F} &= \sum_{\tau=0}^{t} \left( x_{z-z',\tau,j}^{E,F} - x_{z-z',\tau-1,j}^{E,F} - x_{z-z',\tau-1,j}^{E,F} \right) \\
\forall z \to z' \in B, j \in J, t \in T
\end{align*}
\]

The amount of H\textsubscript{2} delivered to zone \(z\) should equal the truck capacity times the number of discharged trucks minus the number of charged trucks, adjusted by the H\textsubscript{2} boil-off loss during truck transportation and compression, as follows:

\[
H_{z,j,t}^{\text{TRU}} = \left( 1 - \sigma_i \right) q_{z,j,t}^{\text{DIS}} - q_{z,j,t}^{\text{CHA}} E_j^{\text{TRU}} \\
\forall z \to z' \in B, j \in J, t \in T
\]

The charging capability of truck stations is limited by their compression or liquefaction capacity, as follows:

\[
q_{z,j,t}^{\text{CHA}} E_j^{\text{TRU}} \leq H_{z,j,t}^{\text{TRU}} \\
\forall z \in Z, j \in J, t \in T
\]

IV. Case Studies in the U.S. Northeast

We apply the HSC planning model to evaluate the least-cost infrastructure needed to serve potential H\textsubscript{2} demand in transportation in the U.S. Northeast, based on simulating annual operations through operations over 20 representative weeks. The model is solved with Gurobi on a 40-core Intel Xeon Gold 6248 with 8 GB RAM.

A. Data Descriptions

Below is a brief description of the input parameters used to define the U.S. Northeast case studies, with further details available in the supporting document.

We focus on two types of H\textsubscript{2} generation technologies: electrolysis and natural gas fueled SMR (with and without CCS). We consider truck and pipeline as the key modes of H\textsubscript{2} transmission. We also model them as potential storage resources, in tandem with stationary H\textsubscript{2} storage. We model two types of trucks, based on handling H\textsubscript{2} as a cryogenic liquid or compressed gas, while the pipelines are considered
Fig. 2. Schematic of the truck scheduling model. The upper row represents the trucks full of H\textsubscript{2}, and the lower row represents empty trucks. Without loss of generality, zone z is shown as the H\textsubscript{2} exporting zone, while zone z' is the importing zone. Each truck can be dispatched to any zone and route.

Fig. 3. (a) Geographical zone classification for U.S. North-East and average H\textsubscript{2} demands for each zone. (b) Average price profiles generated from a power system capacity planning model for the studied U.S. Northeastern region.

The U.S. Northeast region is represented in the model as 6 zones as shown in Fig. 3 (a). The distances are measured by the distances between the polygon centroids of each zone. As Zone 2 and 4 are heavily urbanized, we do not allow central SMR to be built there in the model. The H\textsubscript{2} demands for each zone are developed based on available fuel consumption data and hourly charging profiles for both light- and heavy-duty fuel cell electric vehicles (FCEV) and the relative penetration of FCEV [29], [30]. The average H\textsubscript{2} demands in the units of tonne/hour and MWt (lower heating value) are labeled in Fig. 3 (a), based on a 20% FCEV penetration.

The electricity price profiles for the 20 representative weeks that are inputs to the HSC planning model are derived from a power systems capacity expansion model (CEM) for the U.S. Northeast under to the same carbon policy constraints as considered for the HSC model [31]. The CEM evaluates the least-cost mix of generation and storage technologies required to serve the prescribed electricity demand in 2050 based on modeling annual grid operations using the same representative weeks [32]. The electricity profiles under various carbon prices are presented in Fig. 3 (b).

B. Results

1) Optimal H\textsubscript{2} generation mix: Fig. 4 shows the optimal generation mixes in HSC with different carbon prices and unit capital cost of electrolyzer, which highlight several key observations. First, Fig. 4 (a) shows that as the carbon price increases, the H\textsubscript{2} generation switches from central SMR, to SMR with CCS, and then to electrolyzer. Second, with decreasing capital cost, electrolyzer is cost-effective for deployment at lower carbon prices. For example, as seen in Fig. 4 (b), installed electrolyzer capacity at $100/tonne CO\textsubscript{2} price is 44 tonne/hour (2.4 GW) for an electrolyzer capital cost of $700/kW as compared to 59 tonne/hour (3.1 GW) for $300/kW. Thirdly, although carbon price increase favors an increasing share of generation from electrolyzer, it has a relatively small impact on the installed capacity of SMR with CCS in H\textsubscript{2} generation. SMR with CCS remains a cost-effective source of H\textsubscript{2} supply for time periods when electricity prices are very high for all carbon prices (see Fig. 3 (b)).

The last observation can also be confirmed in Fig. 5, where the electrolyzer produces H\textsubscript{2} when the electricity price is below approximately $30/MWh. The results point to cost-effectiveness of electrolytic H\textsubscript{2} supply with moderate carbon policy ($50/tonne or greater) and electrolyzer capital cost reduction ($300/kW or lower). In the following discussions, we choose $300/kW electrolyser cost and $100/tonne carbon price as the benchmark scenario to explore other aspects of the HSC model outcomes.

2) Truck scheduling model comparison: TABLE I compares the computational complexity and optimal investment decisions of our proposed model (linear truck scheduling) with that of the integer model (integer truck scheduling) and the model in existing literature ("Existing" model in TABLE I, assuming a fixed transport capacity limit and ignoring (25)-
(30 in the proposed model) [13–15, [18–20]. Two cases are examined, one is the base case, the other is a mini case with one representative week and gas truck only. The mini case highlights how relaxing truck scheduling variables to continuous rather than integer significantly reduces computational time while achieving almost the same planning outcome (only less than 0.3% deviation in the H₂ truck and generation capacities). Notably, the integer model for the U.S. Northeast with 20 weeks is computationally intractable for the imposed model time limit of 24 h. The existing model without flexible truck scheduling over-invests both trucks (by 86%) and stationary storage (by 213%) because it does not allow trucks to be shared across different routes (as transmission) and zones (as storage) and to serve as storage simultaneously, resulting in an 11% increase in H₂ supply cost. Moreover, electrolyzer generation increases (by 10%) with truck sharing in the proposed model, which effectively enhances electrolyzer flexibility to respond to temporal variability in electricity prices while meeting H₂ demands.

3) Storage and transport functions of resources in the HSC: In the base case, H₂ pipeline is not economically competitive. However, it could become attractive if the existing natural gas pipeline infrastructure can be retrofitted at relatively low cost for transporting H₂. Therefore, we also evaluate the case with 50% pipeline cost in addition to the base case. The supplied storage capacities and the annual amounts of stored H₂ and transported H₂ in both cases are summarized in TABLE II. In the base case, mobile storage resources including gas and liquid trucks supply more than 70% of the total H₂ storage capacity and throughput. Gas trucks have higher contributions than liquid truck in both storage and transport, partially due to the lower cost and energy consumption of gas compression than liquefaction. In the case with 50% pipeline cost, pipelines are built to handle over half of the total transported H₂, reducing the need in truck for transport compared to the base case. As the truck capacities decrease, the need in stationary storage rises in turn, while the mobile storage resources still contribute approximately 60% of the total stored H₂. Although pipelines present significant storage capacities through line packing, they are hardly used as storage, because they incur less operational costs than trucks in transport and should be used for transport as much as possible.

Fig. 6 illustrates how mobile storage, both gas and liquid trucks, and stationary storage serve the HSC in response to the electricity price and demand fluctuations in a representative week. During off-peak electricity price periods, storage resources store H₂ during times of low H₂ demand and release H₂ during times of high H₂ demand. In the first short peak-price period (Hour 33–47), the trucks mostly serve as storage by releasing H₂. During the longer peak-price period (Hour 111–168), the storage resources are insufficient (or not cost-efficient to be over-built) to meet local demands, and the trucks are used for transporting and delivering H₂ from other zones installed with central SMR facilities.

TABLE III compares the optimal infrastructures in systems with and without significant electrolytic H₂ generation. If pipeline is cheaper with retrofitting, more pipelines will be built in the system with less electrolytic H₂ generation.
($500/kWh electrolyzer, $50/tonne CO$_2$ price) than the base case. This implies that trucks have synergy with distributed electrolysis, because they are more flexible and cost-efficient than pipelines to support intermittent electrolytic H$_2$ generation. Pipelines are more cost-efficient to cope with large and steady transmission demand in the centralized SMR production pathway, while electrolyzers can be deployed in a more distributed manner and thus complement smaller-scale and more flexible hydrogen transmission mechanisms like trucks.

V. CONCLUSIONS

Assessments on the role of hydrogen in future low-carbon energy systems have to contend with the multiple end-uses of hydrogen along with the plurality of technological options for its production, transport and storage. Here, we propose a least-cost HSC infrastructure planning model that accounts for a variety of operational and policy constraints, the model including: a) temporal and spatial variability in H$_2$ demand and renewable energy generation; b) a wide range of hydrogen-related technology options, and c) scalable representation of the flexibility offered by hydrogen truck and pipeline scheduling for transmission and storage functions.

Application of the model to study HSC outcomes in the U.S. Northeast reveals the potential for electrolyzer to be cost-effective under moderate carbon policy and electrolyzer cost reduction ($50/tonne carbon price and $500/kW unit capital cost). Enabling trucks to be shared across zones (as storage) and routes (as transmission) is critical to fully exploit their flexibility for VRE integration and HSC cost minimization.

If the hydrogen demand increases as it penetrates into the heating and industrial sectors in the future, the HSC will have a greater impact on the electricity price and becomes a price-maker. Then the planning of HSC requires coupled modelling of power systems and HSC, which is an area of future work. More complex and accurate modelling of pipeline flow rate and linepack and including the option of retrofitting natural gas pipeline are also interesting future directions.

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1 Transportation Demand

1.1 Average Hydrogen Refuelling Demand

Table S1: Average Hourly Hydrogen Demand for Light-Duty (LDV) and Heavy-Duty (HDV) vehicles [1, 2]

| Zone   | LDV Demand (tonne/hour) | HDV Demand (tonne/hour) |
|--------|-------------------------|-------------------------|
| Zone 1 | 25                      | 6                       |
| Zone 2 | 159                     | 33                      |
| Zone 3 | 57                      | 12                      |
| Zone 4 | 123                     | 21                      |
| Zone 5 | 39                      | 9                       |
| Zone 6 | 55                      | 46                      |
| Zone 7 | 0                       | 0                       |
1.2 Hydrogen Refuelling Profile

![Hydrogen Refuelling Profile](image)

Figure S1: Hourly hydrogen refuelling profile normalized based on the mean.

1.3 Hydrogen Demand Profile Calculation

$H^D_z$: the sum of LDV and HDV demands, as shown in Table. S1

$U_{z,t}$: hydrogen refuelling profile, as shown in Fig. S1

$$D_{z,t} = H^D_z \cdot U_{z,t}$$

2 Inter Zone Distances

Table S2: Inter-Zone Distances for Hydrogen Supply Chain Model ($L_{z\rightarrow z'}$, mile)

| Zone | 1   | 2   | 3   | 4   | 5   | 6   |
|------|-----|-----|-----|-----|-----|-----|
| 1    | 0   | 317 | 504 | 602 | 487 | 608 |
| 2    | 317 | 0   | 199 | 297 | 179 | 340 |
| 3    | 504 | 199 | 0   | 99  | 158 | 333 |
| 4    | 602 | 297 | 99  | 0   | 216 | 358 |
| 5    | 487 | 179 | 158 | 216 | 0   | 186 |
| 6    | 608 | 340 | 333 | 358 | 186 | 0   |
3 Electricity Price Profiles

Description:

1. Power system capacity expansion model used to generate prices for each zone and hour of the year ([http://energy.mit.edu/eps/tools/genx/](http://energy.mit.edu/eps/tools/genx/))

2. Greenfield setup considered for capacity expansion. Existing capacity considered for hydro, pumped storage and transmission infrastructure

3. 20 representative weeks are modelled for annual operations, based on methods described in [3]

4. Capacity expansion in transmission of electricity is not allowed in the base case model

Load Data:
2018 NREL electrification futures study (EFS) projected load for 2050 with assumed BAU technology advancement and reference electrification. Reference: [https://data.nrel.gov/files/126/EFSLoadProfile_Reference_Moderate.zip](https://data.nrel.gov/files/126/EFSLoadProfile_Reference_Moderate.zip)

Resource Characterization:

1. **Renewable Data Source**: NREL Wind Toolkit (onshore and offshore wind) and National Solar Radiation database (solar)

2. Offshore wind is included with no capacity limits and single resource profile for zone 2 and zone 4 based on sampling sites from the NREL Wind Toolkit that overlaps with the areas for which leases have been auctioned

3. Three types of hydropower resources included in the model: Reservoir hydro (with flexible generation and constraints on weekly energy generation limits), run-of-river hydro (inflexible generation) and Canadian hydro imports (Zone 7, flexible with weekly energy generation limits)

3.1 Power System Technology Cost and Performance Assumptions

| Technology          | Capital Cost $/MW | Capital Cost $/MWh | Lifetime year | Fixed O&M Cost $/(MW-year) | Fixed O&M Cost $/(MWh-year) | Variable O&M Cost ($/MWh) |
|---------------------|-------------------|--------------------|---------------|---------------------------|-----------------------------|---------------------------|
| Onshore Wind        | 1,085,886         | -                  | 30            | 34,568                    | -                           | 0                         |
| Offshore Wind       | 1,901,981         | -                  | 30            | 48,215                    | -                           | 0                         |
| Utility-Scale Solar | 724,723           | -                  | 30            | 11,153                    | -                           | 0                         |
| Li-ion Battery      | 120,540           | 125870             | 15            | 2,452                     | 3071                        | 0.03                      |
| Pumped Hydro        | 1,966,151         | -                  | 50            | 41,000                    | -                           | 0.02                      |
| CCGT                | 816,971           | -                  | 30            | 10,560                    | -                           | 2.77                      |
| OCGT                | 815,863           | -                  | 30            | 12,230                    | -                           | 7.14                      |
3.2 Power System Capacity Mix

Figure S2: Optimal Power System Planning Results for the U.S. Northeast in 2050

4 Hydrogen Generation Cost and Performance Parameters

Table S4: Parameters of H₂ Generation Technologies, in 2019 US$ [4–8]

|                     | Electrolysis | SMR | SMR w/ CCS |
|---------------------|--------------|-----|------------|
| $M_{k,z}^{\text{GEN}}$ (tonne/hour) | 0.06 | 9.2 | 9.2 |
| $c_k^{\text{GEN}}$ (M$\$$)          | 3    | 161 | 296 |
| $\eta_{k,z}^{\text{ELE}}$ (MWh/tonne) | 53   | 0   | 0   |
| $\eta_{k,z}^{\text{GAS}}$ (MMBtu/tonne) | 0    | 146 | 160 |
| $e_k^{\text{GEN}}$ (tCO₂/tH₂)       | 0    | 10.0| 1.0 |
| Lifetime (year)       | 10   | 25  | 25 |
5 Hydrogen Transmission and Storage Parameters

Table S5: Parameters of H\(_2\) Transmission and Storage in 2019 US$ [9–13]

| Pipeline | Gas Tank |
|----------|----------|
| \(c^\text{PIP}_i\) (M$/mile) | \(c^\text{STO}_s\) (M$/tonne) | 2.8 | 0.58 |
| \(E^\text{PIP}_i\) (tonne/mile) | \(\Phi^c_s\) ($/(tonne/hour)) | 0.3 | 0.5 |
| Lifetime (year) | \(\Phi^e_s\) (MWh/tonne) | 40 | 2 |
| \(\alpha^c_i\) ($/mile-unit) | \(\beta^c_i\) ($/unit) | 700 | 0.75 |
| \(\alpha^e_i\) (MWh/tonne-mile) | \(\beta^e_i\) (MWh/tonne) | 1 | 1 |
| \(R^\text{PIP}_i\) | | 0 | |

| Liquid Truck | Gas Truck |
|--------------|-----------|
| \(E^{\text{TRU}}_j\) (tonne) | \(E^{\text{TRU}}_j\) (tonne) | 4 | 0.3 |
| \(c^{\text{TRU}}_j\) (M$/mile) | \(c^{\text{TRU}}_j\) (M$/mile) | 0.8 | 0.3 |
| \(o^{\text{TRU}}_j\) ($/mile) | \(o^{\text{TRU}}_j\) ($/mile) | 1.5 | 1.5 |
| \(\sigma_j\) | \(\sigma_j\) | 0 | 3% |
| Lifetime (year) | Lifetime (year) | 12 | 12 |
| \(\Gamma^c_j\) ($/(tonne/hour)) | \(\Gamma^c_j\) ($/(tonne/hour)) | 32 | 1.5 |
| \(\Gamma^e_j\) (MWh/tonne) | \(\Gamma^e_j\) (MWh/tonne) | 11 | 1 |
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