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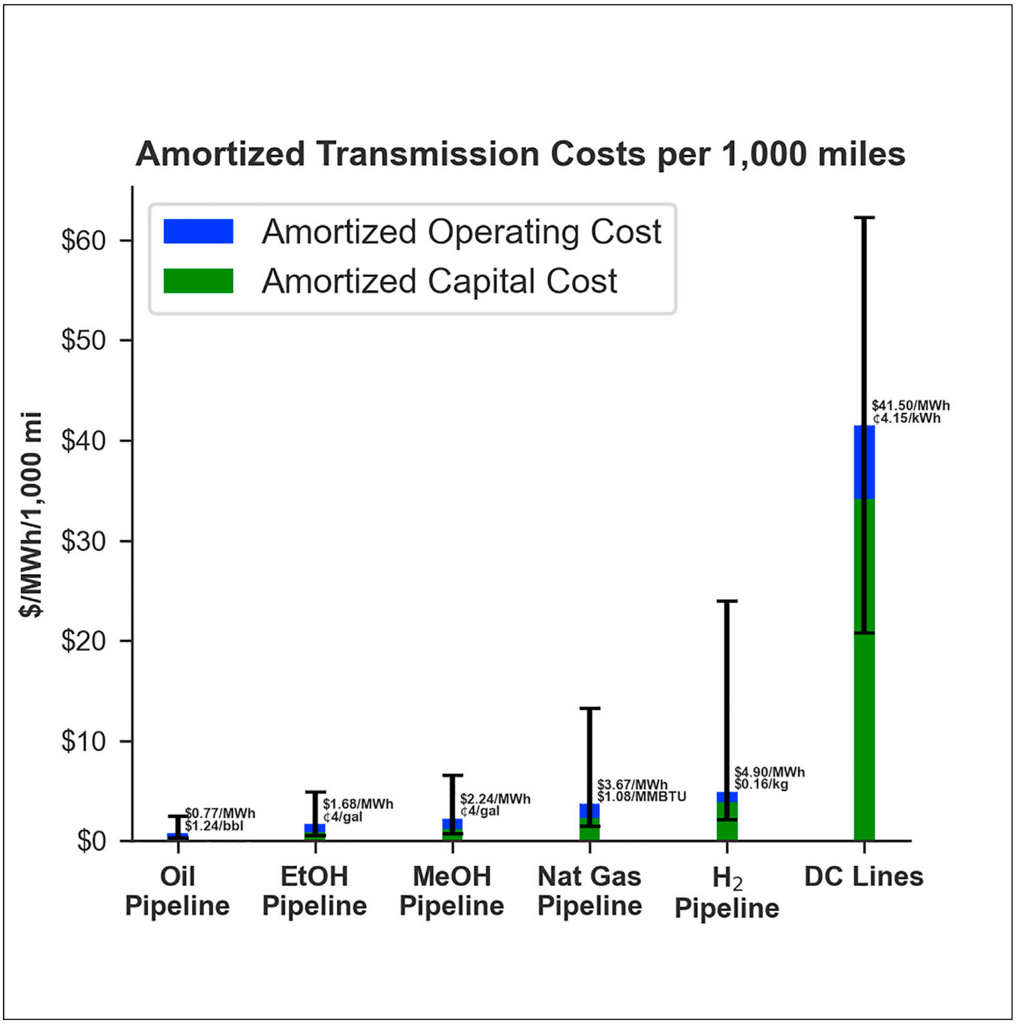

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Highlights

Energy transmission over 1000s of miles will likely be needed in decarbonized economy

Transmission by electricity is much more expensive than by gaseous and liquid carriers

DeSantis et al., iScience *24*, 103495
December 17, 2021
https://doi.org/10.1016/j.isci.2021.103495

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Article

Cost of long-distance energy transmission by different carriers

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SUMMARY

This paper compares the relative cost of long-distance, large-scale energy transmission by electricity, gaseous, and liquid carriers (e-fuels). The results indicate that the cost of electrical transmission per delivered MWh can be up to eight times higher than for hydrogen pipelines, about eleven times higher than for natural gas pipelines, and twenty to fifty times higher than for liquid fuels pipelines. These differences generally hold for shorter distances as well. The higher cost of electrical transmission is primarily because of lower carrying capacity (MW per line) of electrical transmission lines compared to the energy carrying capacity of the pipelines for gaseous and liquid fuels. The differences in the cost of transmission are important but often unrecognized and should be considered as a significant cost component in the analysis of various renewable energy production, distribution, and utilization scenarios.

INTRODUCTION

The modern economy critically depends on moving large amounts of energy over long distances. For example, a supertanker carries the equivalent of about 3 TWh in petroleum (2-million-barrel capacity at 5.46 MMBtu/bbl) halfway around the globe from terminals in the Middle East to refineries in America or Asia. A coal train moves about 100 GWh worth of coal (130 cars × 120 tonnes each at 22.7 MJ/kg) over thousands of miles from mines in Wyoming to power plants on the East Coast. There are multiple renewable energy options, including solar, wind, geothermal, as well as nuclear fission, capable of producing energy at a scale large enough to satisfy energy demands currently being supplied by fossil fuels. However, the required land areas and potential geographic mismatch between energy production sites and energy demand sites must be carefully considered. For example, to replace a 1 GW baseload power plant (24 GWh/day) with a solar power generation at a solar irradiation rate of 4kWh/m^2/day (GHI Solar Map, 2014) and a PV efficiency of 20%, the required collection area would be approximately 30 km^2, or roughly half the area of Manhattan. Most cities consume much more than 1 GW of power and the idea of covering city centers or suburbs with solar panels is impractical for many reasons. Conversely, another option for large-scale renewable power production would be to locate large remote energy farms outside of densely populated urban areas. In this case, energy will have to be accumulated and transported on a very large scale. This is a tenable and renewable option for large urban and industrial areas where energy demand may be too high for local solar power installations. However, this approach also has challenges, such as that most concentrated wind and solar resources in the United States are available in the Great Plains and Southwest regions, whereas regions of the country having the highest populations, and thus greatest energy demand, are located on the East and West Coasts.

According to an Lawrence Livermore National Laboratory analysis shown in Figure 1, the United States consume about 100 Quads (~105 EJ = 1.05*10^{20} J) of energy per year (LLNL, 2020). Out of this amount, about 33 Quads are useful energy services in all sectors of the economy, whereas 67 Quads are rejected energy. Renewable power is expected to have higher efficiency and to generate significantly less waste heat. Still, to replace all the energy currently generated from petroleum, natural gas, and coal, at least 40 Quads (~40 EJ) of wind and solar energy will have to be produced annually in the USA. (Available hydro power is almost completely utilized already and nuclear power has its own set of challenges which currently prevents rapid growth in nuclear power generation.) This is approximately a 10-fold increase from about 4 Quads of current renewable electricity production, and about 3 times higher than the total current electricity generation in the US.

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https://doi.org/10.1016/j.isci.2021.103495

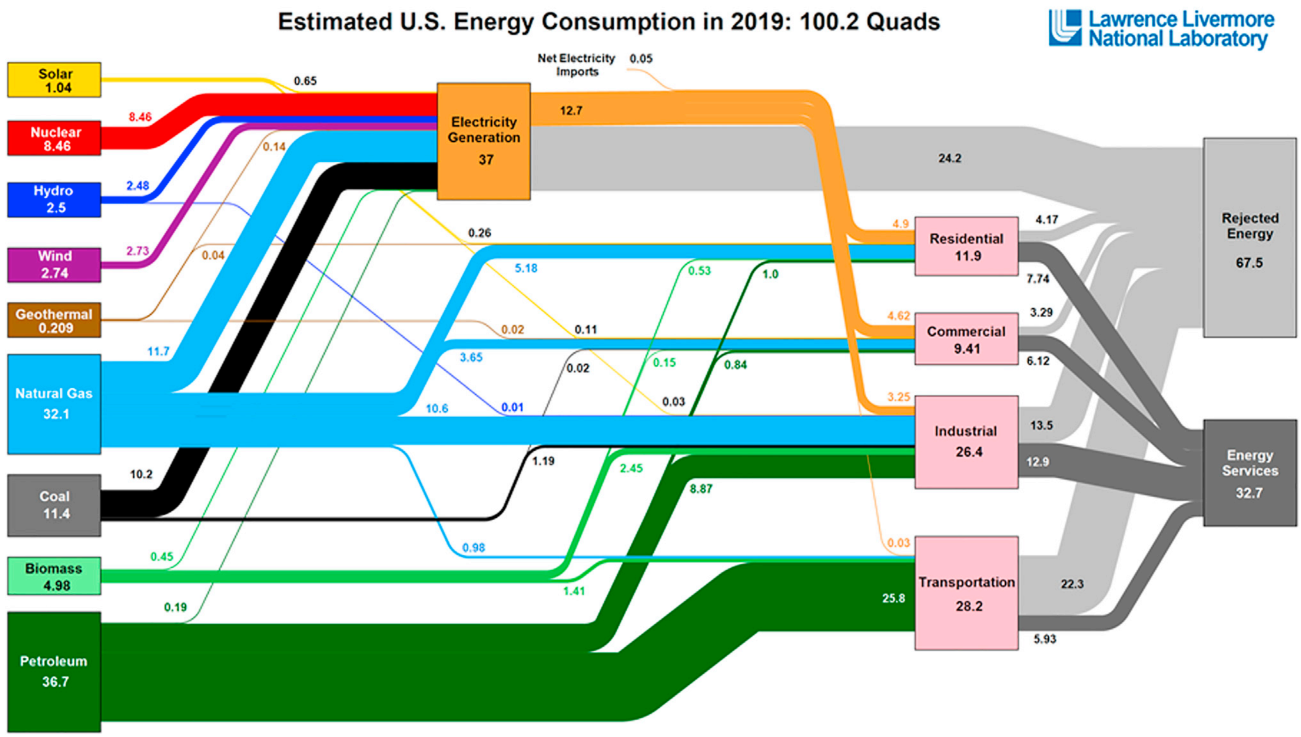

Figure 1. Sankey diagram for energy consumption in the United States in 2019 compiled by Lawrence Livermore National Laboratory and the US Department of Energy
(LLNL, 2020).

The National Renewable Energy Laboratory (NREL) has analyzed availability (technical potential) of various forms of renewable energy in the USA (Lopez et al., 2012). A map of the technical potential for combined wind and solar power shows that the highest concentration of these renewable resources is located in the Midwest region of the country (Figure 2). Even assuming the resource potential at the highest value of 200 GWh/yr/mi^2, as shown in Figure 2, collecting 40 Quads (~40 EJ) of wind and solar energy would require a land area of about 60,000 sq. mi, or roughly a square with a side of 250 miles (400 km). Obviously, with the lower wind and solar technical potential found on the East and West Coasts, the required land area would be many times larger. It is likely, therefore, that large amounts of renewable energy will have to be collected in the Midwest regions of the country and transported over thousands of miles to densely populated areas on the shores.

It is generally assumed that electricity and the existing electrical grid will be the primary means of delivering renewable energy to consumers. Electricity generally provides higher efficiency in power applications than do chemical energy carriers. However, for many large, mobile power applications where high energy density is required, e.g., large ships, trucks or jet airplanes, chemical fuels will be preferable to electricity. For such applications, remote renewable energy can be converted into chemical energy through electrolysis or other water splitting technologies to produce hydrogen. Hydrogen, in turn, can be combined with captured CO_2 to produce methane (synthetic natural gas) or net zero carbon liquid fuels, such as methanol, ethanol, or synthetic oil products, each of which can also be used to transport renewable energy (Ahlgren, 2012; Goeppert et al., 2014; Lim, 2015; Matzen et al., 2015; Lyubovsky, 2017). These are all well-developed, commercially practiced technologies, which can be rapidly deployed on a large scale.

Although significant comprehensive analysis of transmission costs required for integration of variable renewable electricity generation into the power grid can be found in literature (Gorman et al., 2019; Lamy et al., 2016; Tröndle et al., 2020), surprisingly little literature is available on comparing the cost of energy transmission by electricity and by other types of energy carriers. Such comparison is complicated by

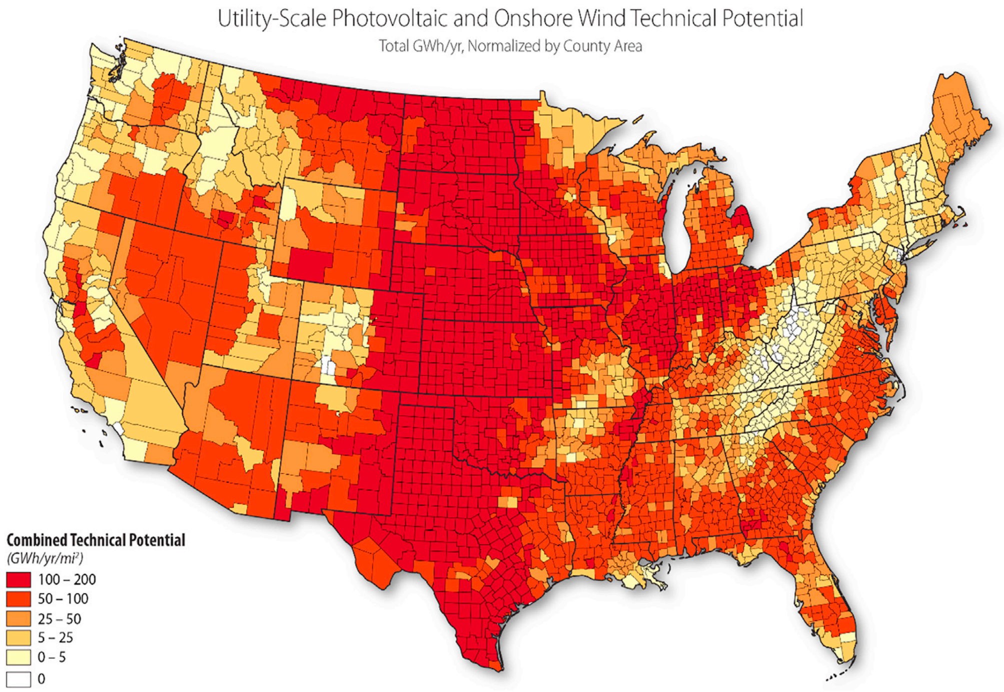

Figure 2. Combined technical potential for on-shore wind and utility scale photovoltaics resources in the USA by county normalized by the county land area in GWh/yr/mi^2

Data source: NREL analysis, (Lopez et al., 2012). Map courtesy of Nicholas Gilroy.

the costs for construction of electricity transmission lines and oil and gas pipelines are often being evaluated using broadly varying sets of technical and financial assumptions and reporting units. Furthermore, electric transmission lines are built not only to link new generation capacity but also to provide reliability and distribution services to the grid in general, which makes it difficult to attribute the cost of construction to transmission capacity.

In a recent work F. Saadi et al. (2018) compared the relative costs of transporting energy by electricity and chemical fuels using a common set of assumptions and concluded that "the cost of electricity and hydrogen transmission are substantially higher than the cost of oil and natural gas transportation". In this work we have conducted a more comprehensive study of the cost of long-distance energy transmission by electricity vs. gaseous (natural gas and hydrogen) and liquid (oil, ethanol, and methanol) energy carriers under a set of consistent technical and financial assumptions. A total transmission distance of 1,000 miles is assumed as a baseline case. This is approximately the distance between St. Louis, MO and New York City, NY and is meant to represent large-scale long-distance transport. The cost of energy transmission is estimated as the levelized capital costs for building new transmission lines and the operating expenses and energy losses associated with transmission. The costs presented here are normalized per unit of delivered energy (based on the lower heating value of the delivered fuels) and expressed as capital cost ($/mile/MW) and total transmission cost per unit of delivered energy over specified distance ($/MWh). All calculations are completed with a utilization factor of 100%, assuming that the given transmission method is being used continuously at nominal design capacity. Although 100% utilization is unlikely for real-world application, such an assumption provides the lowest levelized cost of energy transmission for all carriers and allows for accurate comparison of the cost of transmission between electrical transmission lines and fuel pipelines. Sufficient cost breakdown details are given in the paper to allow the reader to estimate capital costs ($/mile-MW) at other utilizations. Unlike the analysis in Saadi et al., we have accounted for the compressibility of gases in pipeline transmission, the transmission losses for all carriers, and the cost of capital investments. Although there is general agreement in the conclusions between the Saadi et al. and our analysis, there are some significant differences, particularly in the relative cost of energy transmission by electricity and hydrogen. The detailed comparison of the results is provided in the Discussion Section of this paper.

Table 1. Summary data for comparing energy transmission costs in \$/mile, \$/MWh, and \$/mile-MW

	Electrical	Liquid Pipeline			Gas Pipeline	
Energy carrier	HVDC	Crude Oil	MeOH	EtOH	NG	H_2
Total flow (Amp, kg/s)	6,000	1,969	1,863	1,859	368.9	69.54
Delivered power (MWe, MW_{LHV})	2,656	91,941	37,435	50,116	17,391	8,360
Capital cost (\$M/mile)	\$3.90	\$1.47	\$1.92	\$1.92	\$1.69	\$1.38
Power loss in transmission	12.9%	0.78%	2.02%	1.51%	2.67%	1.94%
Capital cost (\$/mile-MW)	\$1,502	\$16	\$51	\$38	\$97	\$166
Amortized cost (\$/MWh/1000 mi)	\$41.5	\$0.77	\$2.2	\$1.7	\$3.7	\$5.0

RESULTS

Cost of transmission over 1000 mi

The combined energy delivery cost analysis results for energy transmission over 1,000 miles are shown in Table 1. The amortized cost in \$/MWh per 1,000 mi combines the total of the operating costs and the amortized capital cost for new line construction. They suggest that energy transmission through pipelines is significantly less expensive than electrical transmission lines. These results are further shown in Figure 3 for capital costs (\$/mile-MW) and in Figure 4 for the total cost (\$/MWh per 1,000 miles). The total transmission cost for pipelines ranges from less than \$1/MWh to \$5/MWh, with the capital cost ranging from \$16/mile-MW to \$166/mile-MW. The electrical transmission cost is above \$40/MWh (¢4/kWh) with an associated capital cost of \$1,502/mile-MW, which is in keeping with published data for electrical transmission (Fares, 2017; Eurek et al., 2016). It should be recognized that different fuels will have different utilization or conversion efficiencies to a useful end-state for various power applications. While liquid fuels consumed in small internal combustion engines generally provide only ~25% efficiency, fuel cells running on hydrogen can produce 60% efficiency, whereas electric motors can provide nearly 100% efficiency (Fuel Cell Fact Sheet – FCTO, 2015).

Table 2 shows a breakdown of the capital costs for each transmission method. Variations in the pipeline cost exist in the materials and labor categories due to cost modifiers for methanol, ethanol, and hydrogen service pipelines. Note that the electrical cost model does not list a miscellaneous cost. Rather, it itemizes an Allowance for Funds Used During Construction (AFUDC)/Overhead cost which is represented in the labor category of this table. The primary cost component of the electrical lines is related to the materials cost, where labor cost plays the most significant role in the pipeline cost. The only exception to this is the compression cost for the natural gas compression station, which exceeds even the labor costs.

The material and labor costs for the methanol and ethanol pipelines are greater than those for oil or natural gas due to the cost modifier applied to pipelines carrying corrosive fluids. Likewise, the material and labor costs for hydrogen pipelines are also higher than those of oil or natural gas due to the ASME code required modifications described in the STAR Methods section. In both cases, the ratio of material to labor costs was preserved between the oil/natural gas pipeline costs and the modified pipeline costs.

Right of Way (ROW) costs for the electrical transmission lines are greater than those of the modeled pipelines. The pipeline data references models are based on ROW costs of actual pipelines built in the United States whereas ROW costs within the electrical transmission model are based on an average BLM land cost (i.e., multiplying acreage per mile of transmission line by the cost per acre as defined as the average of 12 zones within the Bureau of Land Management's Linear Right of Way Schedule). Should the electrical model be recalculated with the entire transmission length assumed to be in BLM Zone 7, the ROW cost would decrease to \$82,800/mile for the transmission line which is similar to \$71,575/mile estimated for ROW cost in an oil pipeline. If the entire electrical transmission line were to be constructed in BLM zone 1, the ROW cost estimated by the Black and Veatch model (Pletka et al., 2014) is a mere \$2,160/mile while if the construction was completed solely in zone 12, the ROW cost would be a significant \$827,760/mile. While this does not close the ROW cost gap completely, it clearly demonstrates the effect the BLM zone can have on ROW cost and provides a possible explanation for the cost differences.

Figure 3 shows the cost results for the modeled capital cost of construction for each transmission method. The shown pipeline results are based on the Rui et al. (2011) cost model. The error bars are representative of

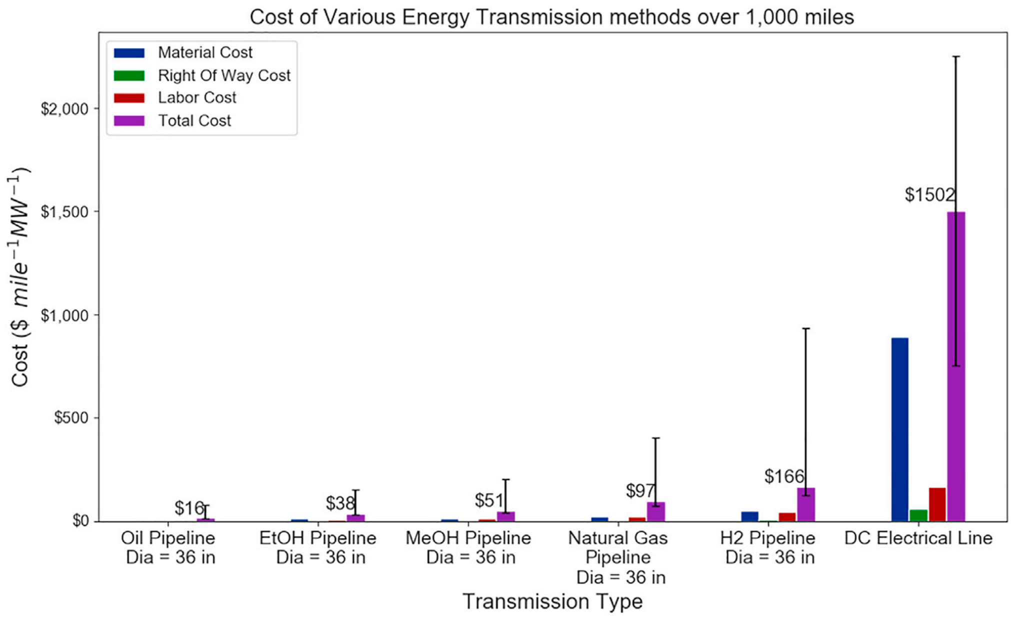

Figure 3. Capital cost of energy transmission over 1000 miles by different energy carriers

Table 2 provides the detailed costs breakdown. Error bars for the pipelines demonstrate the 90% confidence interval resultant from the Monte Carlo analysis. For electricity transmission, +/− 50% of the total cost was used for the error bars in keeping with the estimate range reported in the literature for electrical transmission lines (Saadi et al., 2018; Eurek et al., 2016; Pletka et al., 2010).

the Monte Carlo analysis described in the STAR Methods section. The error bars around several of the pipeline costs appear large in magnitude and are a direct result of the upper bound of the error bars including cost estimates from the Brown et al. (2011) cost model, which has a baseline cost increase of 3.5 times of the Rui et al. cost model. This is in conjunction with increases due to the location of construction (with approximately a 44% cost increase possible from the average cost), and a capital cost modifier that scales proportionally with the baseline capital cost (approximately an additional 24%). Figure 5 further shows the comparison of the capital cost results from this model with cost of transmission data for electrical transmission lines and hydrogen pipelines published in the literature, indicating that while capital cost varies over a broad range, the results from this model are in keeping with similar published results. Figure 4 shows the fully amortized transmission costs ($/MWh per 1,000 miles) over the lifetime of the transmission method. In all cases of transmission pipelines prove to be the most cost-effective method to transmit energy across long distances.

Pipeline cost based on pipeline diameter

The above results were forecasted under the assumption of a 36-inch OD pipeline. It is worthwhile to examine the effect of diameter on transmission cost while all other factors (such as pressure drop, utilization, or compressor/pump efficiency) are held constant. Figure 6 provides an estimation of the capital cost in natural gas and oil pipelines at various diameters. The data predictably shows a significant cost decrease as the pipeline diameter is increased, since the total capacity of the pipeline increases as the diameter of the pipeline increases. (Note, that 100% pipeline utilization is assumed for all cases). The cost of the oil pipeline starts at approximately $100/mile-MW and tapers off to approximately $20/mile-MW. The natural gas cost trend is similar but magnified. The natural gas curve starts close to $500/mile-MW when a 12-inch diameter pipeline is modeled. This cost drops significantly, decreasing below $100/mile-MW in large pipe diameters, though these large pipelines may not be practical for limited supply and demand as few, if any, 46-inch pipelines exist. The hydrogen pipeline curve mirrors the curve demonstrated in the natural gas pipeline, whereas methanol and ethanol pipeline curves mirror those of the oil curve. The baseline case studies above involve developing a cost for the pipeline using a pressure optimization calculation to ensure the optimal number of pumping or compression stations along the pipeline, as described in the STAR Methods section. However, for purposes of developing the cost data in Figure 6, the results are shown for a fixed station spacing as the primary intent is to show the cost trends at various diameters.

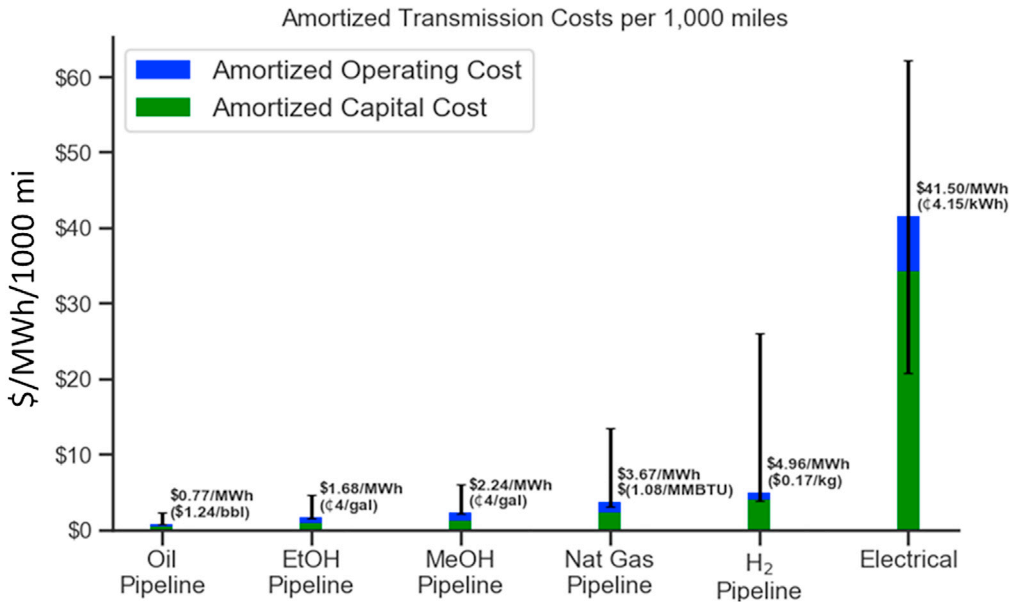

Figure 4. Amortized cost of energy transmission over 1000 mi by different energy carriers

Table 1 provides the detailed costs breakdown. Conversion of the transmission cost into the cost units customary for each energy carrier is shown in the parenthesis. Error bars for the pipelines demonstrate the 90% confidence interval resultant from the Monte Carlo analysis. For electricity transmission, +/− 50% of the total cost was used for the error bars in keeping with the estimate range reported in the literature for electrical transmission lines (Saadi et al., 2018; Eurek et al., 2016; Pletka et al., 2010).

Transmission cost relationship to transmission distance

Although the main analysis focus is on the comparative cost of long-distance energy transmission, the cost variation at shorter distances is also of interest, and in particular, the distance at which cost asymptotes to a long-distance value. Consequently, the length of each transmission method varied between 10 and 2,500 miles and the cost impact computed is shown in Figure 7.

In this analysis the electrical transmission cost is broken down into four primary sub-costs: line & tower costs, AFUDC/Overhead costs, ROW costs, and substation costs. The Black & Veatch cost model maintained an electrical transmission line cost of $2.29M/mile for electrical transmission lines above 10 miles in length, which combines the costs of the transmission cable and the towers. Cost modifiers are added for distances below 10 miles, raising the cost by 20% for transmission distances of 3-10 miles and 50% for transmission distances less than 3 miles. AFUDC/Overhead costs are constant for distances greater than 10 miles, on a $/mile basis. ROW costs, given a similar distribution in area and terrain type, are constant for all lengths on a $/mile basis. Total substation costs are independent of transmission distance, and thus, when assessed on a $/mile basis, substation costs are highest at short distances and declines to an asymptote with distance. Given the consistent cost structure for the majority of cost categories above 10 miles, we focus our study of the effect of transmission distance on distances above 10 miles.

Previously, it was assumed that all electrical transmission over long distances would be conducted by DC lines. However, to ensure that a proper and complete examination over the distance range is presented, 345 kV Alternating Current (AC) lines were also considered. The same costing methodology used for the DC electrical transmission lines was used to create costs for the AC lines with one major exception: no electrical substations at either end of the transmission line were considered necessary for AC lines, as it is expected that the electricity would be both produced and consumed in AC form.

The cost parity point between AC and DC lines occurs around 300 miles (on a $ $mile^{-1}$ MW^{-1} basis). At shorter transmission distances, AC line costs are comparatively low because an AC line is not burdened with the requirement of two HVDC transformer substations (one at each end) as is a DC line. However, as distance increases, the lower-voltage/higher-current of the AC line leads to high power losses and

Table 2. Capital cost breakdown for modeled transmission scenarios

	Electrical	Liquid Pipeline			Gas Pipeline	
Fuel	500 kV HVDC	Crude Oil	Methanol	Ethanol	Natural Gas	H_2
Materials ($M/mile)	$2.291	$0.353	$0.572	$0.572	$0.409	$0.433
Labor ($M/mile)	$0.428	$0.327	$0.530	$0.530	$0.376	$0.401
ROW ($M/mile)	$0.154	$0.0715	$0.072	$0.072	$0.082	$0.081
Misc. Costs ($M/mile)	NA	$0.141	$0.141	$0.141	$0.162	$0.160
Substation costs ($M/mile)	$1.024	NA	NA	NA	NA	NA
Pump/Compressor station costs ($M/mile)	NA	$0.583	$0.603	$0.604	$0.662	$0.308
Total ($M/mile)	$3.898	$1.474	$1.918	$1.918	$1.691	$1.384

All values rounded to the nearest thousand.

thus, high costs per electricity actually delivered. Consequently, DC lines are cost-favoured above 300 miles, though the cost of DC lines begins to increase after approximately 2,000 miles in transmission length, due to the diminished line capacity due to high resistive losses.

In contrast, the cost of transmission for pipelines continues to decrease as the pipeline length increases. Beyond about 500 miles the cost reductions are quite small or are essentially flat for all the pipelines except H_2 pipelines. For H_2 pipelines, the cost curve is slightly steeper and cost reductions continue to occur out to ~2,000 miles. It is expected that the cost curve will become flat at greater distances. This relationship between pipeline length and cost ($ mile^{-1} MW^{-1}) is also seen when looking at the cost categories of the pipelines. Materials, labor, pumping/compressor station costs, and miscellaneous costs all follow similar cost trends as seen for total pipeline costs in Figure 7. The pumping/compressor station cost is both the highest cost contributor and shows the highest percentage decrease after 10 miles, though specific magnitudes of changes are different for each pipeline. The only cost category that does not decrease over the changes in length is the ROW cost, which largely remains flat across all transmission lengths.

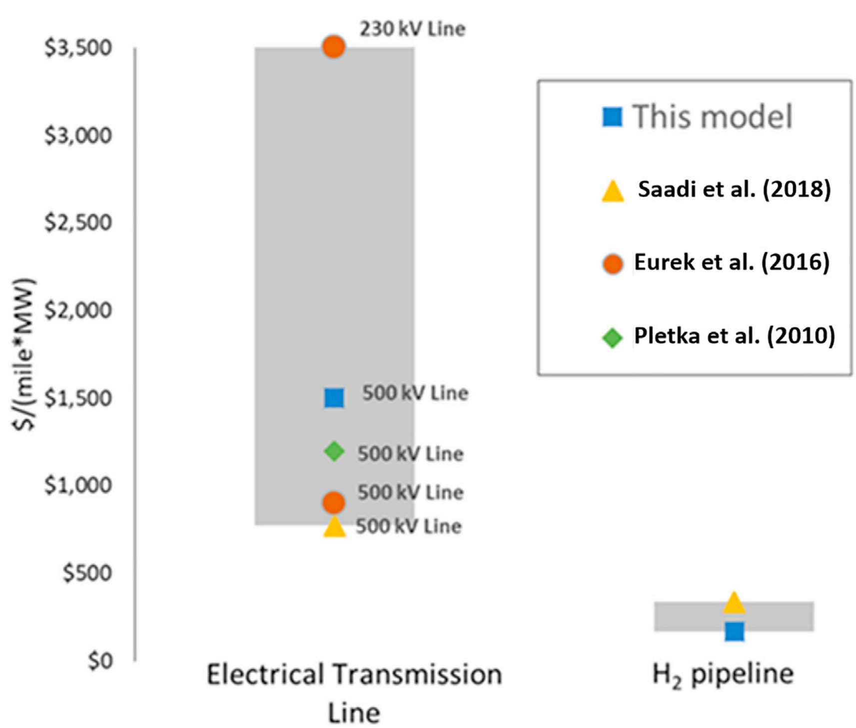

Figure 5. Comparison of the capital cost of long-distance energy transmission by HVDC transmission line and by hydrogen pipeline normalized per (MW*mile) between this model and published literature data.

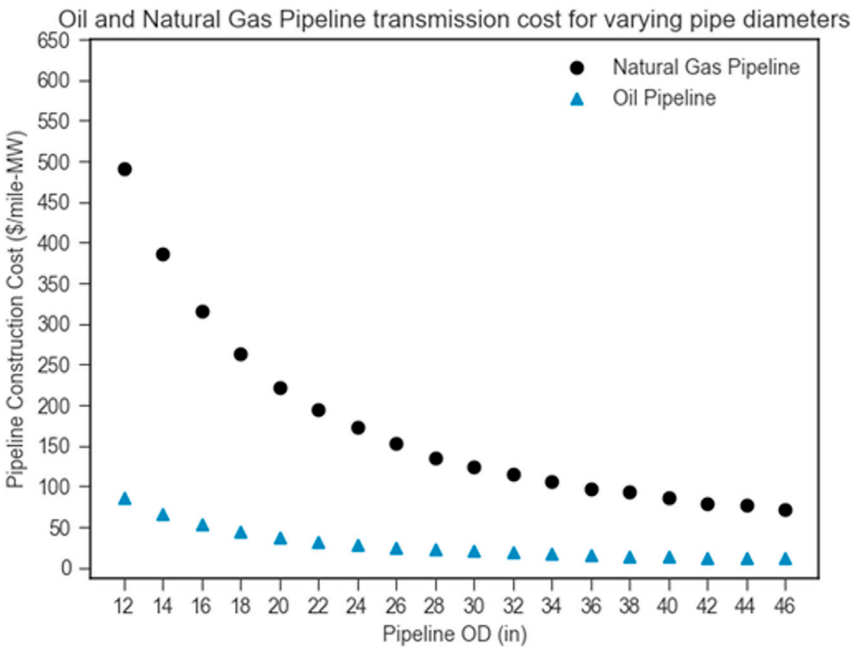

Figure 6. Transmission cost for natural gas and oil pipelines at various pipeline diameters.

Pipeline capital cost variations because of assumed construction location

As described in the STAR Methods section, two different cost models were examined to develop the pipeline capital costs. Each of these models, Rui et al. and Brown et al., breaks the cost of the pipeline down into four categories, materials, labor, right-of-way, and miscellaneous costs. The Brown model bases its cost regression formulas on diameter while the model by Rui is based on the pipeline cross-sectional area and the length of the pipeline. Both models also vary in cost with the region in which the pipeline is completed. Table 3 compares the variation in capital cost of the various models for 36-inch diameter natural gas and oil pipelines using both cost models. The table also shows the effect of the construction location on the cost of the pipeline by listing the highest possible capital cost based on construction location and the lowest possible capital cost based on construction location. Unfortunately, the models by Rui and Brown identify different regions within the U.S (and in the case of Rui et al., Canada is a specified region), the table reports whether the region has the highest or lowest relative cost by region, rather than the specific regions themselves. For reference, the lowest cost region in the Brown model includes the states of Texas, Louisiana, Arkansas, and Oklahoma while the highest cost region in the Brown model covers the Northeastern states of Vermont, New Hampshire, Maine, Massachusetts, Connecticut, and Rhode Island. The lowest cost region in the Rui model is Canada while the highest cost region in the Rui model covers the Southeastern states of Kentucky, North Carolina, South Carolina, Georgia, Alabama, and Florida.

DISCUSSION

Comparison of the results of this paper vs. Saadi et al.

In a recent work F. Saadi et al. (2018) made a similar analysis of the cost of energy transmission by different carriers and concluded that “the cost of electricity and hydrogen transmission are substantially higher than the cost of oil and natural gas transportation”. Table 4 compares the results of Saadi et al. and the results of this study (the results for capital cost and total cost of energy transmission from Saadi et al. are converted from $/kW*km and $/J*km to $/MW-mi and $/MWh per 1,000 mi, respectively). Although in this work only pipeline transmission systems having high carrying capacity were considered for each carrier, Saadi et al. analyzed a broad range of transmission options. Only the transmission methods from Saadi et al. that are most relevant for comparison with this work (e.g. 36-inch diameter pipelines) appear in Table 4.

Table 4 shows that the capital cost for an oil pipeline in $/MW-mi in Saadi et al. is about twice as high as for the value estimated in this work. This is because of a higher estimate of the construction cost in $/mi and

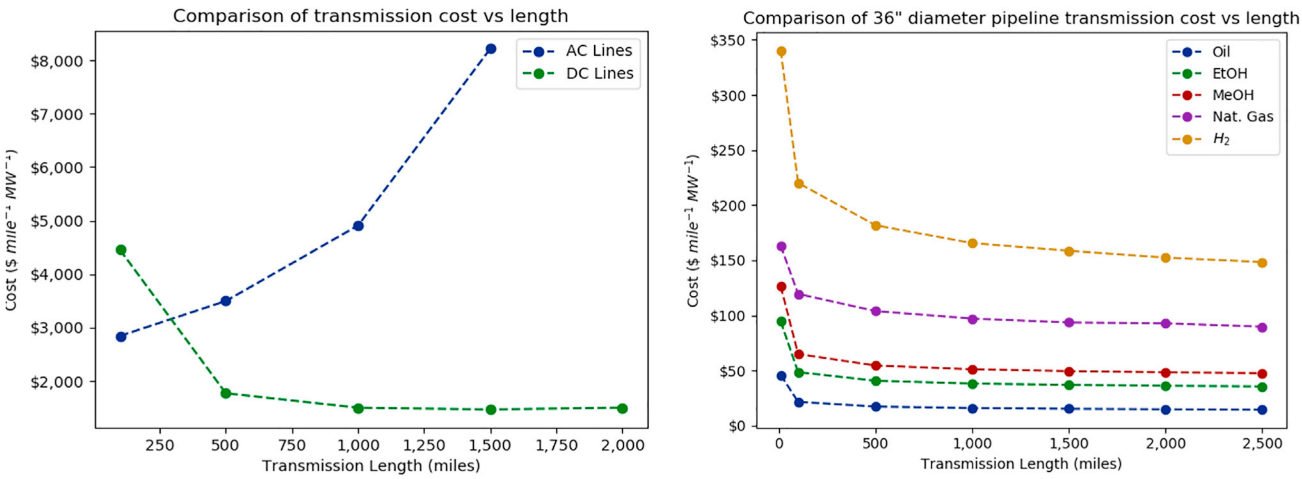

Figure 7. Comparison of transmission cost vs transmission distance.

slightly lower flow velocity. However, the total cost in $/MWh is about 3.4 times higher in this work. This is because of accounting for financial interest and taxes in amortizing the capital cost used in this work, whereas the simple capital recovery method was used at Saadi et al. where they divided the capital cost over the total amount of energy transported through the pipeline over the specified number of years.

The ratio of natural gas to oil pipeline costs in $/mi is similar for both our work and Saadi et al., suggesting a similar set of assumptions between the liquid and gas pipelines. Yet the natural gas pipeline costs presented in this work in $/MW-mi is 50% higher than that of Saadi et al. This is due to significantly higher flow velocity assumed by Saadi et al. and also to the different methodology in calculating the effective gaseous volumetric flow. Saadi et al. assume a constant gas velocity within the pipeline. The calculation method used in this work assumes a significant change in velocity along the pipeline length due to pressure drop and frictional losses. Therefore, the maximum gas velocity (the design maximum shown in Table 4) occurs at the point of minimum fluid pressure in the line (which occurs immediately before repressurization). The velocity is actually much lower after repressurization and the velocity change corresponds to a substantially reduced volumetric flow rate and pipeline capacity, when compared to Saadi et al. This reduced capacity in conjunction with the difference in financial calculations described above for the oil pipeline results in the cost from this analysis being approximately 5 times greater than that of Saadi et al. for natural gas pipelines.

The hydrogen pipeline cost differences between Saadi et al. and this paper are much less than for natural gas because of the hydrogen flow velocity changing much less between compression stations. For the hydrogen pipeline, Saadi et al. estimates higher $/mi construction cost because of required pipeline modifications and lower hydrogen flow velocity which results in $/MW-mi and $/MWh cost for H_2 about 5 times higher than for NG. The work presented in this paper estimates the cost for hydrogen pipelines on a $/mile basis slightly lower than that of natural gas. This lower cost results from fewer compressor stations required for hydrogen recompression. Also because of the lower pressure drop calculated in this paper for hydrogen

Table 3. Cost comparisons for both capital cost models under the assumption that the pipeline is constructed in different regions

			Capital cost ($/mile-MW)	
Fuel	Diameter	Model	Lowest Cost Region	Highest Cost Region
Natural gas	36″	Rui et al. (2011)	$77	$115
Natural gas	36″	Brown et al. (2011)	$191	$493
Oil	36″	Rui et al. (2011)	$13	$18
Oil	36″	Brown et al., (2011)	$35	$92

Table 4. Comparison of the results from this work to selected results from Saadi et al.

	Oil Pipeline (36″)		NG Pipeline (36″)		H_2 Pipeline (36″)		Electricity (500 kV HVDC)	
	Saadi et al. Table 1, Line 3	This Paper	Saadi et al. Table 2, Line 4	This Paper	Saadi et al. Table 3, Line 6	This Paper	Saadi et al. Table 7, Line 10	This Paper
Maximum pressure (Bar,kV)	NA	108	90	100	100	100	500	500
Fluid velocity at maximum pressure (m/s, Amp)	3	3.7	25	8.2	15	14.1	6,000	6,000
Fluid velocity at minimum pressure (m/s, Amp)	3	3.7	25	18.6	15	18.6	6,000	6,000
Capital cost ($M/mile)	2.3	1.5	2.9	1.7	3.2	1.4	2.3	3.9
Capital cost ($/MW-mile)	32.2	16	64.4	97	338.1	166	772.8	1,502
Total cost ($/MWh-1,000mi)	0.23	0.77	0.75	3.7	4.0	5.0	4.4	41.5

transmission relative to natural gas, the volumetric flow is higher in the H_2 pipeline than in the natural gas pipeline. This results in the capital and transmission costs for H_2 estimated in this paper only slightly higher than that for the capital and transmission costs for natural gas calculated in this paper.

The largest difference between Saadi et al. and this work is in the estimate of the transmission cost for electricity. The cost of electricity line construction estimated in this work is about 70% higher than in Saadi et al. This work accounts for a transformer station at the beginning and end of each line, which are not included in the Saadi et al. analysis. The same electricity transmission power rating is used in both works, but due to accounting for transmission power losses, the cost in $/MW-mi estimate in this work is about twice the value of Saadi et al. The above factors, plus differences in the capital cost amortization methodology, result in the electricity transmission cost estimated in this work being nearly 10 times higher than in Saadi et al.

There is general agreement between the two works that the cost of energy transmission by chemical fuel carriers is lower than for electricity. The methodology used in this work accounting for volumetric flow of the compressible gases in the pipelines, power losses in the electric line, and capital cost amortization of the transmission line construction further suggests that the actual cost of the electricity transmission is about an order of magnitude higher than that estimated at Saadi et al.

Cost of transmission relative to energy costs

This work had focused on cost comparison of energy transmission, while largely setting aside the costs of energy production, conversion, and storage on either side of the transmission line. Multiple pathways and energy conversion technologies may be utilized for production and consumption of various energy carriers. For example, on the production side, renewable electricity can be used to generate hydrogen through water electrolysis. There are also photo-electrochemical (PEC) and solar thermochemical (STCH) methods for producing hydrogen directly from solar energy, which are being actively researched (e.g. HydroGen consortium publications). Hydrogen can then be combined with captured CO_2 to produce synthetic natural gas, methanol, ethanol, or liquid hydrocarbons. Alternatively, there is growing research on direct electrochemical reduction of CO_2 or artificial photosynthesis for renewable hydrocarbon fuels production. All relevant delivery scenarios need to be analyzed through comprehensive LCA studies, which should account for all energy conversion, storage, and distribution steps, including the cost of energy transmission.

It is often assumed that in the deeply decarbonized future economy scenarios renewable energy has to be consumed primarily in the form of electricity. Yet, there are large sectors of economy, such as air transportation, ocean shipping, long distance trucking, etc., which will be very difficult to electrify, and which will continue to require a supply of carbon-neutral high energy density carriers (fuels) to operate without producing a net increase in CO_2 emissions. It is difficult to tell *a priori* how much of each type of energy carrier will be consumed in the future economy. From basic market principles, it can be assumed that the carriers which can deliver net carbon zero energy to the consumer at the lowest overall cost and be competitive with fossil alternatives will be in the highest demand.

Table 5. Historic price ranges of common fuels in the USA vs. cost of transmission over 1000 miles

Fuel/energy carrier	Customary price	Price in $/MWh (by LHV)	Cost of transmission, $/MWh/1000mi
Levelized on-shore wind electricity	2-4 ¢/kWh	$20-40	$41.5
Industrial grid electricity	5-15 ¢/kWh	$50-150	$41.5
Renewable hydrogen production	2 - 4 $/kg	$60-120	$5.0
Natural gas	2-4 $/MMBTU	$7-15	$3.7
Methanol	0.8–1.6 $/gal	$50-100	$2.2
Ethanol	1.2–2.4 $/gal	$50-100	$1.7
Crude oil	40-80 $/bbl	$25-50	$0.77

In the interest of comparing the cost of energy transmission and the customary prices of electricity and fuels, Table 5 shows approximate ranges for prices of electricity and gaseous and liquid fuels in the USA over the last few decades converted into the same $/MWh units as the previously calculated costs of energy transmission. For electricity, the cost of long-distance transmission (which still does not include storage and distribution costs) significantly exceeds the cost of renewable electricity production and would constitute the major share of the overall electricity cost. This is consistent with the findings by Lamy et al. (2016) who concluded that to add 40 TWh (~0.15 EJ) of new wind electricity generation in the Midcontinent Interdependent System Operator (MISO) region of the U.S., it is economically beneficial to locate new wind farms in Minnesota and Iowa, rather than in North and South Dakota, despite the latter having significantly better wind resources because of the excessively high cost of electricity transmission from the Dakotas. Production of renewable hydrogen utilizing wind and solar power sources can be comparable in cost to industrial electricity prices. When accounting for transmission over long distances, the cost of hydrogen is within the range of delivered industrial electricity prices. Transmission costs for the liquid and gaseous fuels make up only a fraction of the overall fuel cost.

Although the cost of wind or solar conversion into electricity is well defined by the large scale operation of wind turbines and PV solar farms, the costs of the technologies for renewable energy conversion into gas and liquids, e.g., through water electrolysis and gas-to-liquid processes, are less clear. Currently, production of liquid fuels, such as methanol, using renewable electricity is more expensive than common industrial electricity or fossil fuels (Lyubovsky, 2017). However, large scale deployment of e-fuel production technologies can reduce the production cost of e-fuels in the same way as costs decreased for wind turbines and solar PV energy panels, potentially making the renewable e-fuels cost-competitive with fossil fuel alternatives.

Another important consideration is the efficiency of the energy conversion in different delivery pathways. Hydrogen production by water electrolysis has efficiency of about 60-70% depending on the type of the electrolyzer. Efficiency of e-fuel production can be about 40-50%, depending on the type of fuel produced and the specifics of the synthesis system integration (Zang et al., 2021; Ueckerdt et al., 2021). On the consumption side, when hydrogen or e-fuels are converted back into electricity, the conversion efficiency ranges from approximately 30% for internal combustion generators to approximately 60% for large IGCC turbines or fuel cells. The round-trip efficiency for hydrogen or e-fuels, therefore, is between 15% and 30%. That means that producing hydrogen or e-fuels from renewable energy requires about 4–5 times more electricity production than direct electricity transmission. It is likely that for electrified applications energy delivery in the form of electricity may be preferred, particularly in locations where local sources or renewable electricity are readily available. Low conversion efficiency also suggests that electricity which is already delivered by the grid should not be used for production of hydrogen or e-fuels, but should be directed toward electrified energy applications. On the other hand, green hydrogen and carbon-neutral liquid e-fuels for the power applications, which cannot be readily electrified, such as long-haul trucking, ocean shipping, aviation, etc., should be produced in remote regions having high quality renewable resources where these carriers can be produced at lower cost and transported to consumers over long distances bypassing the electricity grid.

Renewable carbon-neutral liquid fuels provide additional advantages over electrical transmission in that they allow for long-term, cost-effective, and large-scale energy storage. Such storage may address the

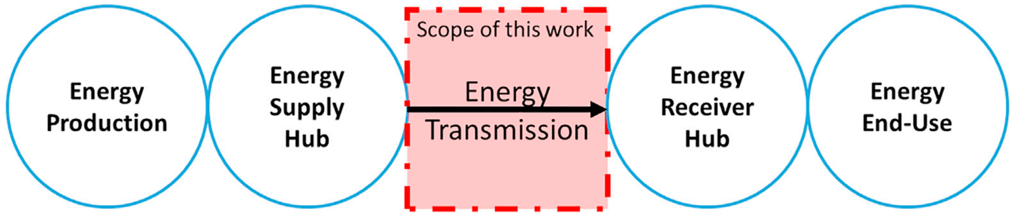

Figure 8. Schematic of the renewable energy delivery cycle
Only the transmission section is analyzed in this work.

renewable energy curtailment problem characteristic for renewable electricity. Combined with much lower transmission cost, such renewable fuels can provide a parallel avenue for utilization of renewable energy resources, particularly at the remote locations not readily accessible by the electricity grid and for power applications which cannot be readily electrified.

Conclusions

The results of this modeling study demonstrate that the cost of electrical transmission per delivered MWh can be up to eight times higher than for hydrogen, about eleven times higher than for natural gas, and twenty to fifty times higher than for liquid fuels. Although the capital costs of construction of electrical transmission lines and the pipelines are about the same (between about $1.5M and $4M per mile, and may significantly vary depending on the particular project size, location, topography, financing options, etc.) the energy-carrying capacity of the electric wires is much lower than for gaseous and liquid pipelines. Multiple electrical transmission lines would have to be built to transport the equivalent amount of energy as a single high-capacity pipeline. Furthermore, operating energy losses are much greater in electrical transmission lines than in chemical fuel transportation. These two factors make electrical transmission the most expensive transmission method among the studied energy carriers. Additional analysis is required to build upon this assessment of transmission costs to assess the feasibility and economics of the alternative renewable energy production-transmission pathways.

Scope and limitations of the analysis

The scope of this work is limited to a comprehensive study of the cost of long-distance energy transmission by electricity, gaseous, and liquid carriers under a set of consistent technical and financial assumptions. For our analysis we assumed that an "energy supply hub" collects and stores the particular energy carrier. Energy is then continuously transmitted by an electrical transmission line or pipeline (as appropriate) to the "energy receiver hub" (Figure 8). A total transmission distance of 1,000 miles is assumed as a baseline case. This is approximately the distance between St. Louis, MO and New York City, NY and is meant to represent large-scale long-distance transport. All calculations are completed with a utilization factor of 100%, assuming that the given transmission method is being used continuously at nominal design capacity. Although 100% utilization is unlikely for real-world application, such an assumption provides the lowest levelized cost of energy transmission for all carriers and allows for accurate comparison of the cost of transmission between electrical transmission lines and fuel pipelines. Sufficient cost breakdown details are given in the text to allow the reader to estimate capital costs ($/mile-MW) at other utilizations.

The costs of the renewable energy carrier production, storage (if needed), and utilization on both the supplier and the consumer sides of the transmission line are not considered in the scope of this work. These costs, however, may be significant. Multiple technologies will be available for each of the energy conversion components in the overall renewable energy delivery and utilization cycle, each requiring its own detailed analysis. The paper largely abstracts from different types of final energy demand that have to be satisfied after long-distance energy transportation, and which may require additional energy carrier conversion before and after the transmission. The analysis does not consider the costs and energy efficiency characteristics of the conversion infrastructure needed at the transmission feed side (e.g. electrolysis, e-fuel synthesis, etc.), nor the costs and efficiency of converting the transported energy back into electricity or some other form that is useful to satisfy the final energy demands. Only the cost of energy transmission by different carriers was analyzed in this work, which often is an underestimated link in the overall renewable energy systems analyses. In order to compare the overall cost of energy delivery by different carriers the required conversion processes on both the supply side and the demand side would also have to be analyzed. We consider this to be largely beyond the scope of this paper as only the cost of transmission itself is accounted for in our analysis. Some discussion of the transmission costs relative to the customary prices of different energy carriers is given in the Discussion section of the paper.

STAR★METHODS

Detailed methods are provided in the online version of this paper and include the following:

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ACKNOWLEDGMENTS

This research was supported in part by an award from the Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy under Award Number DE- EE0007602 and by Alliance for Sustainable Energy, LLC, the manager and operator of the National Renewable Energy Laboratory for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Fuel Cell Technologies Office and by Science and Technology Policy Fellowships administered by the Oak Ridge Institute for Science and Education (ORISE) for the DOE. ORISE is managed by ORAU under DOE contract number DE-AC05-06OR23100. The views expressed in the article do not necessarily represent the views of the DOE, the U.S. Government, ORAU, or ORISE.

The authors want to express sincere gratitude to Neha Rustagi (DOE HFCTO), Eric Miller (DOE HFCTO), Ned Stetson (DOE HFCTO), Sunita Satyapal (DOE HFCTO), Amgad Elgowainy (ANL), Mark Ruth (NREL), Fadl Saadi (ARPA-E), Noah Meeks (Southern Company Services, Inc.), Michael Pesin (DOE OE), Vincent Sprenkle (PNNL), Charlie Gay (DOE SETO), Steve Chalk and Michael Berube (DOE EERE) for reviewing the original work and providing valuable comments and discussion.

AUTHOR CONTRIBUTIONS

Original -. Conceptualization: M.L, Methodology: B.D.J., M.L., D.D., G.S., C.H., Investigating: D.D., B.D.J., M.L., Writing – Original Draft: D.D., B.D.J., M.L., C.H., G.S., Reviewing & Editing: B.D.J. C.H., G.S., Supervision: B.D.J., M.L., Data Curation: D.D., Formal Analysis: D.D., B.D.J.

Revision -. Conceptualization: M.L, Methodology: B.D.J., M.L., D.D., G.S., C.H., Investigating: D.D., B.D.J., M.L., Writing – Original Draft: D.D., B.D.J., M.L., C.H., G.S., Reviewing & Editing: B.D.J. C.H., G.S., Supervision: B.D.J., M.L., Data Curation: D.D., Formal Analysis: D.D., B.D.J.

DECLARATION OF INTERESTS

The authors declare no competing interests.

Received: March 22, 2021
Revised: August 24, 2021
Accepted: November 19, 2021
Published: December 17, 2021

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STAR★METHODS

KEY RESOURCES TABLE

RESOURCE	SOURCE	IDENTIFIER
Software and algorithms		
Overhead Transmission Lines	Pletka et al. (2014)	B&V Project No.181374
Oil & Gas Pipeline Cost	Rui et al. (2011)	https://www.ogj.com/refining-processing/gas-processing/new-plants/article/17213121/regression-models-estimate-pipeline-construction-costs
Oil & Gas Pipeline Cost	Brown et al. (2011)	https://www.researchgate.net/publication/236421832_National_Lab_Uses_OGJ_Data_to_Develop_Cost_Equations
Methanol/Ethanol Pipeline	Kinder-Morgan (2009).	https://afdc.energy.gov/files/pdfs/km_cfpl_ethanol_pipeline_fact_sheet.pdf
Compressor Cost	Rui et al. (2011)	https://www.ogj.com/home/article/17298392/regressions-allow-development-of-compressor-cost-estimation-models

RESOURCE AVAILABILITY

Lead contact

Further information and requests for resources and reagents should be directed to Daniel DeSantis (daniel.desantis@ee.doe.gov).

Materials availability

This study did not generate new unique reagents.

Data and code availability

The input data are available in the Key Resources Table, and the code associated with this article is available from the Lead Contact on reasonable request.

METHOD DETAILS

Nomenclature

C	4.0639; Dimensionless
D	pipe diameter, mm
f	friction factor, dimensionless
G	gas gravity (air=1.0)
h_f	differential head, m
L	Length of pipeline segment, km
P_b	base pressure, bar
P_1	Suction (upstream) Pressure kPa or bar
P_2	Discharge (downstream) Pressure kPa or bar
T	average gas flowing temperature, K (273+°C)
T_b	base temperature, K (273+°C)
Z	Gas compressibility factor at flowing temperature, dimensionless
Brake Power	Unit Power, kW
$\dot{Q}$	Volumetric Flow Rate $\left(\frac{m^3}{hr}\right)$
$\dot{V}$	Standard Volumetric Flow Rate $\left(\frac{Mm^3}{day}\right)$
$\dot{V}$	Gas Flow Rate at standard conditions m^3/day
v	velocity $\left(\frac{m}{s}\right)$
Z_1	Suction Compressibility Factor, dimensionless
Z_2	Discharge Compressibility Factor, dimensionless

φ	specific gravity
γ	ratio of specific heats, dimensionless
Γ	$\frac{\gamma-1}{\gamma}$
η	Pump/Compressor efficiency

High-voltage DC lines for electricity and large diameter pipelines for gaseous and liquid carriers, which are well-established commercial technologies, are analyzed and provide a reasonable set of cases to cover the field of large-scale energy transmission. The cost models for the pipelines and electrical lines used in this work were based on published data sets for construction of commercial above ground projects in the US as summarized in the below Table. Capital investment costs for an electrical transmission line; liquid pipelines carrying oil, methanol, or ethanol; and compressed gas pipelines carrying either natural gas or hydrogen were estimated under an assumption of construction of new transmission lines or pipelines. Hydrogen pipelines do exist in the U.S., if mostly in the Gulf Coast region where the hydrogen is piped between various chemical manufacturers. Only one reference to a functional ethanol pipeline was found to be in operation (Kinder-Morgan, 2009), but no reference to a functional high-pressure, large-diameter hydrogen or liquid methanol pipeline was found by the authors.

Pipeline cost model summary

Transmission type studied	Energy carrier	Reference	Dollar year reporting
Overhead transmission lines	Electricity	Pletka et al. (2014)	2014
Liquid Pipeline	Crude Oil	Rui et al., (2011) Brown et al., (2011)	2009
	Methanol/Ethanol	Kinder-Morgan (2009)	2008
Gas Pipeline	Natural Gas	Rui et al., (2011) Brown et al., (2011)	2009

Electrical transmission line model

A cost model for an electrical transmission line was developed by the Black & Veatch Corporation for use by the Western Electric Coordinating Council (Pletka et al., 2014). This cost model details calculations for transmission line capital costs, Right-Of-Way costs, and Allowance for Funds Used During Construction (AFUDC) costs. The cost model itself allows for the selection of various conductor types, tower designs, voltage classes, and other parameters.

Transmission line design assumptions. The modeled long-distance transmission line selected for this work is an Aluminum Core Steel Reinforced (ACSR) line, as it is a traditionally used line-type for electrical transmission lines. The support structure for this line was selected as a lattice type structure. The construction of these transmission lines requires large amounts of steel, concrete, and aluminum, which predictably makes the cost of materials for the transmission lines a significant cost driver. The selected voltage class is 500 kV HVDC with a nominal capacity of 3,000 MW, as high-voltage DC transmission is preferred for long distance electricity transmission. (Higher voltage systems, e.g. 800 V, have been proposed for long-distance transmission and would lower resistive power losses, but cost data are not available (McCalley et al., 2012)). The cable resistance of 0.057 ohm/mile is assumed as for the "Falcon" type conductors with 0.0108 ohm/1,000ft in the ACSR wire data sheet. Two AC/DC substations, one on each side of the line, are included with the cost for the transmission line. Corresponding substation parameters include a 500 kV substation and HVDC Converter with Ring Bus breakers, 2 transformers per substations, and a 1,500 MVA rating per transformer (Pletka et al., 2014). A summary of key design parameters for electrical transmission line are shown in the below Table.

Electrical line losses. Electrical transmission losses are calculated based on the line electrical current and resistance as described in the Black and Veatch report, according to the following equation:

$$Loss\left(\frac{MW}{mile}\right) = \frac{\left(\frac{I(amps)}{Conductors\ per\ Phase}\right)^2 \cdot \Omega \cdot Conductors\ per\ Phase \cdot No.of\ Circuits}{1e6} * Load\ Adjustment$$

(Equation 1)

$$\text{s.t.}\ \ Load\ Adjustment = \frac{(Utilization + Utilization^2)}{2}$$

Values for the specific voltage class used in this study (500 kV HVDC) are shown in the below Table. In order to account for line losses, the power loss per mile was multiplied by the total line length and then subtracted from the transmission line nominal capacity of 3,000 MW (6,000 Amps at 500 kV). As such, the actual power delivered by the representative electrical transmission line is 2,656 MW. The 344 MW lost to resistive heating accounts for 12.9% of the delivered power for the transmission line in the modeled case. This power loss adds to the transmission cost because it decreases the amount of delivered power and adds to operating costs. The electricity lost to resistance was assumed at a cost of $0.05/kWh. Note, that this calculated loss is much higher than the average electrical losses for transmission and distribution in the U.S. grid, which is about 5% (EIA, no date). This is due to shorter transmission distances and lower average utilization of the current US transmission grid, which was built around coal and NG fired power plants, than the assumptions made in this study for long distance transmission of renewable energy. The above calculations are specific to the modeled case, where the HVDC line configuration, such as the number of conductors per circuit and conductor resistance were selected based on the established practice as reported by Black & Veatch. It can be expected that for the long-distance and high-current bulk electricity transmission conductors with lower resistance, more conductors per circuit, and higher voltages will be used in order to reduce losses. However, this will increase the cost of line construction. It is likely that further optimization of the HVDC line parameters will occur as more long-distance transmission projects are built. Such optimization is beyond the scope of this work.

Summary of modeled parameters for the electrical transmission line spanning 1,000 miles

Design parameter	Units	500 kV HVDC modeled parameter
Design capacity	MW	3,000
Design current	Amps	6,000
Number of conductors per Phase	–	3
Number of circuits per Line	–	2
Number of Phases	–	1
Resistance	ohm/mile	0.057
Utilization	%	100%
Number of substations	–	2
Substation circuit breaker type	–	Ring Bus
MVA rating per transformer	MVA	1500
Number of transformers per substation	–	2

Pipeline models

Gas pipeline model. Two cost models for determining the capital cost for the construction of gas pipelines were considered. The first is a study by Rui et al. (2011) which examines the capital cost of 412 on-shore pipeline construction projects between 1992 and 2008. The second cost model, described by Brown et al. (2011) uses 30 years of on-shore natural gas pipeline cost data, ranging from 1980 to 2010. Both models are derived from data published by the Oil and Gas Journal. The pipeline data covers a wide range of pipeline lengths, though most are substantially shorter than the 1,000-mile transmission distance modeled within this work. However, the cost models should be relevant, as capital costs for pipelines above 2 mile in length are relatively consistent on a $/mile basis (Brown et al., 2011). The work presented here is most appropriate for comparing the transmission cost of pipelines and electrical lines of long length (~1,000 miles) but is also generally applicable to lengths as low as 100 miles.

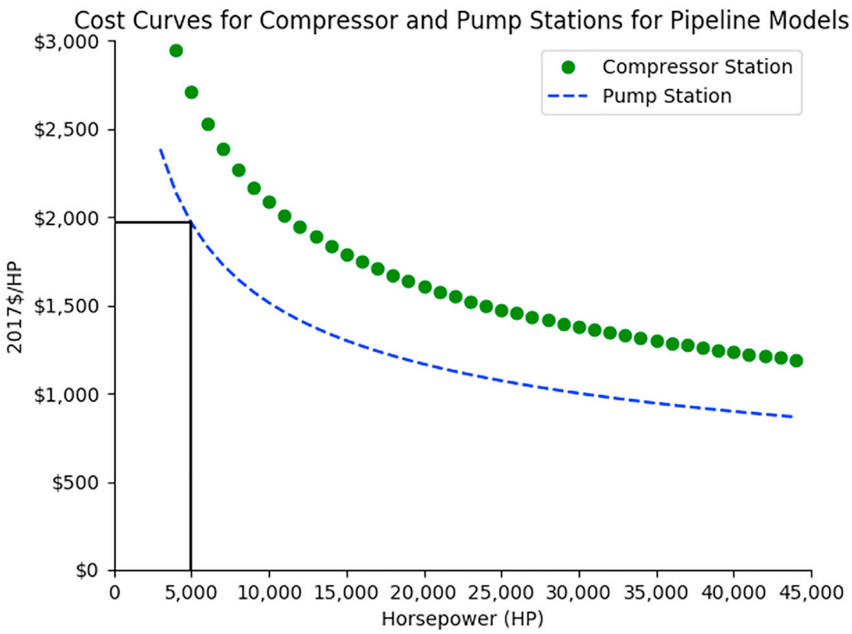
Both regression-based capital cost models are primarily based on the diameter of the pipe and detail the cost of material, labor, and right-of-way (ROW) for different regions of the United States. Brown et al. further suggests that a 37% miscellaneous cost adder be included for all gas pipelines while Rui et al. includes a regression cost model for miscellaneous costs. Neither cost model includes capital costs for compressor stations. The baseline costs described below primarily use the Rui cost model, due to its more specific cost model and the inclusion of only recent data. However, to give the reader an idea of the magnitude of the difference in costs generated by the two models, cost projections using both the Rui and Brown models are compared below. Given that compression costs can be a significant portion of gas pipeline costs, a compressor cost model, also developed by Rui et al. (2012), was used to estimate the costs of compressor stations based on their power requirements.

An examination of the literature and publicly released information regarding gas fuel pipelines yielded no reference to any existing large-diameter, high-pressure hydrogen pipelines. Consequently, hydrogen pipeline cost is predicted using a modified form of the natural gas pipeline cost model. The primary change to the model was a cost adder that is meant to account for the cost to prevent hydrogen embrittlement of exposed metal surfaces. Embrittlement is a known problem for certain types of steel pipelines in hydrogen service. Maintaining yield strength at the traditionally high operating pressures of a transmission pipeline makes designing and costing a pipeline capable of withstanding the internal pressures difficult. Work presented in Fekete et al. provides a series of design assumptions and cost estimates that specify the likely cost premium of creating a steel pipeline for use in hydrogen service. Fekete et al. projects that hydrogen pipelines constructed in accordance with the recently approved ASME code B31.12 would have 8% higher material and labor costs than similar pipelines pipeline designed for natural gas service (Fekete et al., 2015).

Liquid pipeline model. Despite an exhaustive search and requests for information from various energy and environmental agencies, no suitable cost data or cost models for liquid fuel pipelines were identified. The natural gas pipeline cost model was deemed the most suitable estimate for a crude oil pipeline as both are metal pipelines of comparable pressure and diameter. Appropriate adjustments were made for liquid fuel vs. natural gas operations (e.g. incompressible vs. compressible fluids, pumping stations vs. compression stations). Three liquid fuels were considered: crude oil, methanol, and ethanol. Crude oil was selected as a baseline energy carrier currently in use. Methanol and ethanol were chosen as two common renewable fuel options. Other chemical fuels could also be passed through a pipeline.

The construction cost of oil pipelines is assumed to be the same as the construction cost of natural gas pipelines. Ethanol and methanol pipeline costs found in this work are based on the cost of an oil pipeline plus a capital cost adder to adjust for a more corrosive fluid. The cost adder is derived from a Kinder-Morgan fact sheet describing the conversion process and costs of an oil pipeline to an ethanol pipeline: conversion costs were approximately $10M for a 16-inch diameter, 106-mile pipeline (Kinder-Morgan, 2009). The cost of the modifications was scaled linearly by the circumference and length of the pipeline and applied as a cost adder to the oil pipeline cost models. It is assumed that, for purposes of this study, the cost adder for an ethanol pipeline is the same for a methanol pipeline, though this assumption is used without a known reference to an existing methanol pipeline or associated cost.

Pumping station cost models. Like the liquid fuel pipeline construction costs, pumping station costs for crude oil and other liquid fuels have not been well-documented. A single reference point was identified, that of a 5,000 horsepower (HP) pumping station at $1,500/HP in 2004 dollars. This cost inflates to approximately $1,966/HP in 2017 dollars (Menon, 2004). The Rui cost model for compressor stations was scaled and adjusted for inflation, so that a cost curve with an identical shape would be created for the pumping stations but would intersect the reference point (see below Figure).



Compressor and Pump Station Cost Curves

The vertical and horizontal lines represent the cost of a 5,000 HP pumping station in 2017 dollars ($1,966/HP).

Pipeline design assumptions. Given the wide variety of parameters that affect the capital cost of pipelines, several design constraints were adopted to model an appropriate pipeline for large-scale energy transmission over 1,000 miles. First, it is assumed that the pipelines are metal pipelines with an interior polymer coating. Second, the pipeline length is the same as the modeled electrical transmission lines (1,000 miles). Third, pipeline diameters were restricted to a large size currently used in transmission operations (36 inches), though the models are capable of examining smaller and larger diameters. Fourth, pipeline utilizations are set at the upper limit of 100%, to allow broad comparisons between different pipelines and the electrical transmission lines. (Pipeline utilization is normally high, greater than 95% (Menon, 2004)). Finally, all pipelines are assumed to be aboveground pipelines.

Gas pipeline design parameters. The representative long-distance, high-capacity gas pipeline is modeled as having an inlet pressure of 100 bar, as is consistent with typical current gas operating pressures for natural gas pipelines (Fekete et al., 2015). Pipe wall thickness is a function of pressure and is calculated as described in ASME B31.12-2011 PL-3.7 (ASME B31.12, 2012) with yield strength for pipe taken as 70,000 psi, which is appropriate for API 5L X70 pipe. Due to the different compressibility factors and gas densities of natural gas and hydrogen, many design parameters vary between these two gases. For example, gas velocity was selected by application of the erosional velocity formula equation (Equation 2) which leads to differing flow velocities for each system.

$$v_{max} = \frac{c}{\sqrt{\rho}} \qquad \text{(Equation 2)}$$

The factor c represents an empirical value that depends on several factors including the corrosiveness of the fluid, material of the pipe, whether the pipe service is continuous or intermittent, the density of the fluid, and the amount of solid particulate that may be in the fluid (PetroWiki, n.d.). The American Petroleum Institute (API) and various pipeline companies may define different values for c. For this work, the value selected for c is consistent with values that are suitable for gas pipelines with corrosion resistant coatings and does not allow for velocities exceeding the recommended gas pipeline velocity of ~24.5 m/sec (80 ft/sec) (ASME B31.12, 2012). The modeled c-factors and velocity are shown in the below Table. Good practice dictates not running a system at its maximum design point, and thus, rated gas velocity is modeled at 90% of the maximum velocity for each fluid. Note that for compressible gas flow the maximum velocity is reached at the lowest pressure before the compressor station. All pipeline costs are thus based on the rated flow with the understanding that in practice pipelines may operate below this operational value.

The velocity of the gas is directly related to the volumetric flow rate of the gas and varies along the length of the pipeline due to changing pressure. The volumetric flow rate of a gas in a pipeline is defined by the General Gas Flow Equation (also known as the Fundamental Flow equation) (Menon, 2005):

$$\dot{V}\left(\frac{m^3}{day}\right) = 1.1494x10^{-3}\left(\frac{T_b}{P_b}\right)\left[\frac{\left(P_1^2 - P_2^2\right)}{GTLZf}\right]^{0.5} D^{2.5} \quad \text{(Equation 3)}$$

The general gas flow equation computes the standard volumetric flow rate that results for a specified pressure drop between two points (i.e. compressor stations) that are a specified distance apart. The equation adjusts for gas compressibility, pipe wall friction, and the gas gravity (relative molar mass compared to air). It is critical to account for gas gravity when comparing natural gas (G=0.554) vs. hydrogen (G=0.0696) due to the order of magnitude difference between the gravities of each compound.

In an otherwise equivalently designed pipeline, natural gas and hydrogen would experience different pressure drops for a given flow length. In order to optimize the pressure drop for both NG and hydrogen, a cost optimization function was used to balance the compression power (and thus compression station cost) with the number of compression stations required over the 1,000 mile pipeline. Pressure drops in the range between 2 and 60 bar were examined. The pressure drop providing the lowest amortized transmission cost was selected as the modeled pipeline reported here. Velocity and pressure drop are key variables that affect nearly every other design and operational parameter. As such, many of the pipeline design parameters stem from these two values, and variations between the natural gas and hydrogen design parameters and operational costs are due to these changes. A summary of key design parameters are shown in the below Table.

Design parameters for modeled gas-carrying pipelines

Design parameter	Units	Natural gas	Hydrogen
Pipeline diameter	In	36	36
c-factor	$kg^{0.5}m^{-0.5}s^{-1}$	155	55
Peak Design Velocity[a]	m/s	18.6	18.6
Maximum Pressure[b]	Bar	100	100
Pressure drop between stations	Bar	56	21
Compressor station spacing	miles	84	111
Pipeline material of construction	–	API 5L X70	API 5L X70
Pipeline wall thickness	In	0.5	0.75
Adiabatic compressor efficiency	%	85	85
Std. Volumetric flow rate	m^3/day	4.5×10^7	6.6×10^7
Pipeline utilization	%	100%	100%

[a]The design velocity is listed for the fluid at its fastest point in the pipeline, which would be immediately before the compressor station repressurizes the fluid.
[b]The maximum pressure is listed for the fluid immediately after the compressor station repressurizes the fluid. The flow velocity at this point is the lowest.

Given the aforementioned embrittlement issues of pipelines in hydrogen service, the existing ASME code requires a design factor of 0.5 when calculating pipeline thickness as opposed to the design factor of 0.72 used for natural gas pipelines (Fekete et al., 2015). Further, special requirements for welding materials and procedures under current ASME code would also drive up the cost of construction for pipelines in hydrogen service (Fekete et al., 2015). These cost increases have long been projected to be necessary should hydrogen pipelines ever be used for transmission (Parker, 2004; Schoots et al., 2011; Bjorck and Grahn, 1999). This work uses the natural gas pipeline construction costs described in Rui et al. to predict that cost of construction for hydrogen pipelines, and then raises that cost by 8%, as suggested by Fekete et al., to account for the increased steel thickness, welding, and associated labor requirements needed for hydrogen service pipelines. Compressor station costs are not increased from the previously described model as it is expected that the material, welding, and labor costs required for wetted pipe are a small fraction of the total cost of a compressor station. Variations in compressor station costs between natural gas and hydrogen service pipelines are due to the different compression requirements for natural gas and hydrogen (Schoots et al., 2011).

Liquid pipeline design parameters. While variability exists in gas pipeline design parameters, there is limited variability between design parameters for liquid fuel pipelines. Similar to gas pipelines, the maximum velocity of the pipeline can be calculated from the erosional velocity equation (Equation 1). It is suggested that liquid pipelines maintain a velocity below 4.57 m/sec (15 ft/sec) to minimize erosion (Pipeline design consideration and standards, n.d.). A recommended value for the c-factor is 122 when dealing with liquids in steel pipe (Pipeline design consideration and standards, n.d.). After calculating the maximum velocity for each liquid fluid examined in this work and finding all of the maximum velocities reasonably close to the recommended maximum velocity, the c-factor was kept at 122 for all liquid pipelines examined. The operational velocities for each fluid were placed at 90% of the maximum velocity, as in the gas pipeline cost models. The operational flow rate for oil, approximately 3.69 m/sec (12.1 ft/sec), is in keeping with publicly reported flow rates for 36-inch pipelines, though specific pipelines may operate at different operational velocities depending on circumstance (Porter et al., 2011).

For the liquid pipelines, the fluid is modeled as incompressible and thus has constant velocity at all points along the pipeline. However, a high pressure drop is still required to maintain targeted flow rates with practical spacing of pumping stations. Fluid pressure within the liquid pipeline is modeled as starting at 108 bar and decreasing to 5 bar at the inlet to the next pumping station. 108 bar was selected as it the highest pressure rating by an existing API 5L X52 pipe thickness, preventing the need for specialized piping or a higher grade pipe. The pump efficiency is set at 80% for all liquid pumps. A summary of key design parameters are shown in the below Table.

Design parameters for modeled liquid-carrying pipelines

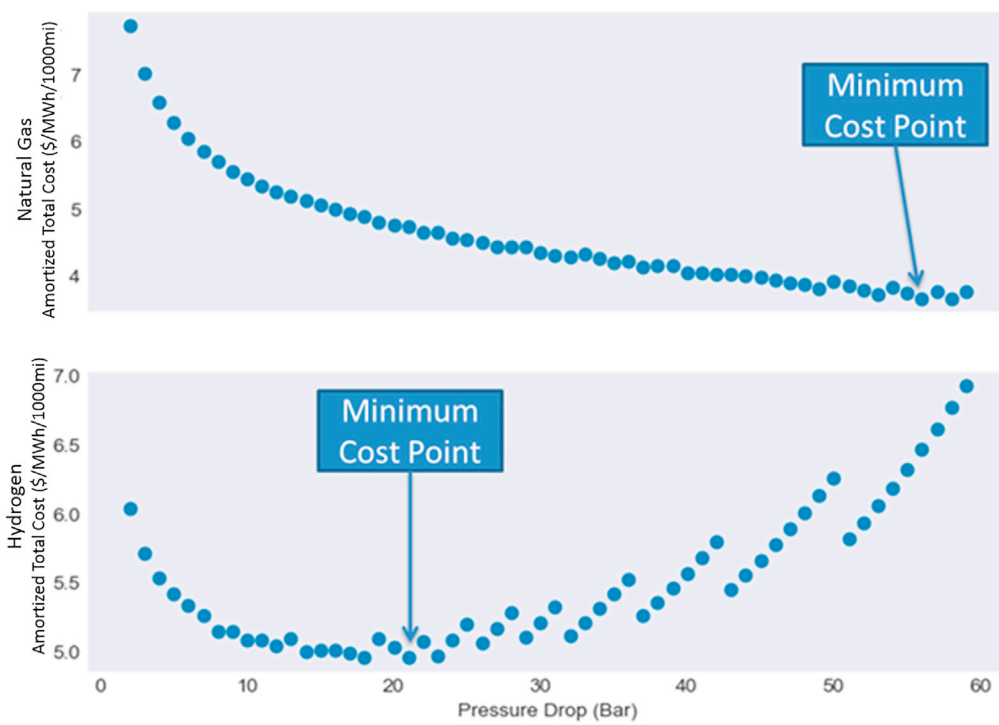
Design parameter	Units	Oil	Methanol	Ethanol
Pipeline diameter	in	36	36	36
c-factor	$kg^{0.5}m^{-0.5}s^{-1}$	122	122	122
Peak design velocity	m/s	3.69	3.90	3.91
Initial pressure	bar	108	108	108
Pressure drop between stations	bar	103	103	103
Pump station spacing	miles	41	41	41
Pipeline thickness	in	0.75	0.75	0.75
Pipeline material of construction	–	API 5L X52	API 5L X52	API 5L X52
Pump efficiency	%	80%	80%	80%
Volumetric flow rate	m^3/h	8,011	8,468	8,484
Pipeline utilization	%	100%	100%	100%

Pipeline pumping and compression power. Pipelines are designed and maintained to prevent fluid losses, due to issues such as leaking, for obvious economic and environmental reasons. While some studies report seemingly large losses from the national natural gas grid, many pipeline companies report losses of less than 5% or even less than 1% (Brandt et al., 2014; Ogburn, 2013). We assume for the purpose of this study, that leaks from large energy transmission pipelines will have a negligible impact on levelized cost, and we therefore do not account for leak rates. It is worth noting that any losses would proportionally increase the transmission cost in the pipelines, by reducing the delivered energy rate without lowering the corresponding capital expenses for construction. Significant power, however, is required to pump liquid fuels and compress gaseous fuels for delivery. In order to account for the operation of the pumping or compressor stations, the requisite power for each pumping or compressor station is calculated from Equation 4 or Equation 5, respectively. The power requirement is then multiplied by the number of stations required over the pipeline length to compute the total power requirement for the pipeline. The power requirement for the pumping or compressor stations is assumed to be provided by imported electricity at \$0.05/kWh and the cost of used electricity is applied to provide an operating cost for the pipeline.

$$\text{Pump Brake Power} = \frac{\dot{Q} \cdot h_f \cdot \varphi}{367.47 \cdot \eta} \quad \text{(Equation 4)}$$

$$\text{Compressor Brake Power} = C \cdot \Gamma^{-1} \cdot \dot{V} \cdot T_1 \cdot \frac{Z_1 + Z_2}{2 \cdot \eta}\left[\left(\frac{P_2}{P_1}\right)^{\Gamma} - 1\right] \quad \text{(Equation 5)}$$

Optimization of the number of compressors over 1,000 mi. The results of the pressure drop optimization studies are shown in the below Figure. They show that the natural gas lines have the lowest amortized transmission cost ($/MWh) when the pressure drop between the compressor stations is 56 bar, while hydrogen pipelines have an optimum pressure drop of only 21 bar. This is due to the low viscosity of hydrogen, which results in lower pressure drop for the same flow velocity than in the case of NG and allows for fewer repressurization stations. Note that the stepwise nature of the cost curve for hydrogen in the below Figure is due to step-wise decrease in the number of compressor stations with increasing pressure drop and distance between the stations, while the higher required compressor power results in increasing cost per each station. Pressure drop optimization studies were also conducted for liquid fuel lines but the results did not indicate large enough price variation to deviate from the existing pipeline pressure drop data that was referenced in model development. Complete model pressure drop information, including pump and compressor stations operating power, are shown in the below Table.



Optimization study for natural gas and hydrogen pipelines pressure drop between compressor stations
The minimum is found at 56 bar and 21 bar, respectively.

Pump and compressor data table

Transmission Method	Liquid Pipeline			Gas Pipeline	
Fuel	Crude Oil	Methanol	Ethanol	NG	Hydrogen
Pipe diameter (in)	36	36	36	36	36
Flow velocity (m/s)	3.7	3.9	3.9	18	18
Pressure drop (bar/mile)	2.5	2.5	2.5	0.67	0.19
Pump/compressor load (MW_e/station)	29	30	30	39	18
Pipeline Operating Power (MW_e/1,000mi)	715	757	758	464	162

Cost analysis

Capital cost amortization. The costs of capital investment for building new transmission pathways were amortized over the assumed lifetime of the equipment.

$$Amortized\ Cost = \frac{CapEx * (crf + \%\ maint + \%\ misc.)}{Annual\ Operation\ Time} * \frac{1}{Delivered\ Power * Capacity\ Factor}$$

where

$$crf = \frac{\left(\frac{r*(1+r)^n}{(1+r)^{n-1}}\right) - \frac{tax\ rate}{n}}{(1 - tax\ rate)}$$

crf – is capital recovery factor, r – interest rate, n - lifetime of the project.

The key amortization assumptions are shown in the below Table. In addition to annual expenses for repayment of the initial capital, annual expenses for maintenance, repair, and operation are also incurred. Pipeline operating costs are normally between 4-7% of the pipeline capital cost and are dominated by the cost of pumping or compression power required (Omonbude, 2016). Since pumping/compression-related expenses are accounted for separately in this work, we estimate all other annual expenses at 0.5% of the given pipeline capital cost.

Key factors for amortization of capital costs	
Interest (Discount) rate	8%
Misc. Costs per year	5% of Total Capital Cost
Maintenance costs per year	5% of Total Capital Cost
Operating Expenses[a]	0.5% of Pipeline Cost
Corporate tax rate	26.6%[b]
Capital recovery factor	~12%[c]
Equipment lifetime (amortization Period)	Gas Pipelines: 33 yr Liq. Pipelines: 33 yr Elect. Transmission: 60 yr

[a]Operating costs for running the electrical transmission lines are included in the cost of model and are 0.5% for this parameter to account for other operational expenses.
[b]The Effective Tax Rate is calculated as the Federal Tax Rate + State Tax Rate *(1- Federal Tax Rate). The Federal Tax Rate, as of 2018, is 21%. The national average State Tax Rate according to www.taxfoundation.org for 2018 is 7.10%.
[c]The difference between a 33 and 60 year lifetime leads to no appreciable difference in capital recovery factor.

Based on the cost estimation methodologies previously identified for each transmission pathway, computation cost models were created in Python v3.6.1 and used for all subsequent statistical and comparative analyses. All cost results are reported in 2017 dollars.

Monte Carlo analysis. Within the pipeline models, numerous parameter values were selected to be representative of actual energy transmission systems. However, the potential to operate a pipeline at conditions other than those modeled introduces uncertainty into the cost projections. Additionally, the various capital cost models for pipelines show significant variation between models and between construction locations. In order to determine the range of likely costs for a pipeline, a Monte Carlo analysis was conducted. In the Monte Carlo analysis, the variable parameters are randomly and simultaneously selected over a range of possible values as shown in the below Table. First, the Monte Carlo analysis selects a randomized cost model between the Rui and Brown cost models. This selection is evenly weighted and averages to a 50:50 selection. The model also randomly selects a region of construction, in which the entire 1,000 miles of pipeline is assumed to be constructed in a region specified by its respective model. This selection is also evenly weighted.

Parameters varied for Monte Carlo Analysis

Parameter varied	Units	Probability distribution	Lower limit	Most likely value (if applicable)	Upper limit
Gas initial pressure	Bar	Triangular	90	100	130
Liquid initial pressure	Bar	Triangular	30	140	160
Liquid low pressure	Bar	Triangular	1	5	25
Pump efficiency	%	Triangular	60	80	90
Compressor efficiency	%	Triangular	80	85	95
Operational velocity factor	–	Triangular	.75	.90	1.0
Transmission length	miles	Triangular	100	1000	2000
Pump/Compressor station cost modifier	–	Triangular	0.75	1	1.25
Pipeline capital cost modifier	–	Normal	Normal Distribution of Capital Cost with a 15% standard deviation of the mean		
Model selection	–	Binary	Brown Model vs. Rui Model		
Construction region	–	Even Distribution	Even possibility of any given construction region being the location of the entire pipeline		

All parameters (except where noted) were varied in a triangular distribution in which the baseline modeled value was considered the most likely value for the Monte Carlo analysis.

Following these selections, other modeled parameters were stochastically varied. The variables altered were the pipeline inlet pressure, the liquid pipeline final pressure, the pump or compressor efficiency, the operational velocity of the fluid, a capital cost modifier on the pump or compressor stations, and a capital cost modifier on the pipeline. 100,000 iterations were run and the results were recorded. A confidence interval of 90% was selected and the minimum and maximum values of the confidence interval are taken as the bounds of the most likely range for costs. These bounds are representative of the bounds of uncertainty in the analysis and represent the error bars shown in Figures 3 and 4.

Cost model comparisons. The various models all reported costs in different basis years, so consumer price index (CPI), based on Bureau of Labor Statistics (BLS) data, was used to adjust costs to year 2017 dollars and thereby allow a fair comparison between the various transmission methods. Additionally, since the transmission methods have different energy carrying capacities, costs were normalized by the amount of delivered energy, where energy capacities for chemical fuels are based on the lower heating value (LHV). Results are reported for capital cost (in both $/mile and $/mile-MW), and transportation cost ($/MWh). This allows for comparison not just on the traditional cost per mile scale, but also provides a sense of how much it costs for power to be transmitted by different carriers. All costs incorporating the power or energy of the carrying method are considered to be at their peak flow rates and include losses from electrical transmission or the energy requirement for pumping or compressing the respective fuels all assessed at $0.05/kWh.