Argonne NATIONAL LABORATORY

ANL-18/26

Economic Data and Modeling Support for the Two Regional Case Studies

Nuclear-Renewable Hybrid Energy Systems: Analysis of Technical & Economic Issues

Nuclear Science and Engineering Division

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Nuclear-Renewable Hybrid Energy Systems: Analysis of Technical & Economic Issues

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1. Introduction

This report includes cost inputs for the simulation framework developed for the Nuclear-Renewable Hybrid Energy Systems (N-R HES) project, including capital and O&M cost data for solar photovoltaic and wind turbines, in Section 2. Section 3 focuses on the costs of hydrogen storage and transportation, while Section 4 includes the initial results of a study of the optimal penetration of renewables in the N-R-HES system, under various conditions. This latter study also provided the opportunity to gain familiarity with the HYBRID framework, while initiating the generation of a useful set of cases that highlight the value of hybrid energy systems.

2. Capital cost of Solar PV and Wind

2.1 Data and context

EIA (2016) includes the "*current and future projected cost and performance characteristics of new electric generating capacity*", including both capital and O&M costs, of various electricity generating technologies, as estimated by the Energy Information Administration (EIA) in their most recent report on this topic, including on-shore wind and solar photovoltaic (PV). The work was performed by an external consultant group (Leidos Engineering LLC) and was sponsored by the DOE-EIA, in order to develop updated input parameters for the National Energy Model System (NEMS). A previous report on the same topic was released in 2013 (EIA 2013).
The reference costs for solar photovoltaic and for onshore wind, from EIA (2016), are shown in Table 1.

Table 1 Summary capital and O&M costs for wind and solar green-field installation, from (EIA 2016).

	Reference Capacity (MW)	Overnight cost ($/kW)	Fixed O&M cost ($/kW-y)	Variable O&M cost ($/MWh)
On-Shore Wind	100	1,877	39.7	0.0
Solar Photovoltaic - Fixed	20	2,671	23.4	0.0
Solar Photovoltaic - Tracking	20	2,644	23.9	0.0
Solar Photovoltaic - Tracking	150	2,534	21.8	0.0

The capital costs of Table 1 are compared with the corresponding capital costs of EIA (2013), in Table 2. It is observed that wind and solar installations experienced a cost reduction of 25% and 67%, respectively, for the specific technologies and capacities that are present in both editions of the EIA report. These reductions over 3 years correspond to an annual reduction of 7.3% and of 15.6% annually, respectively. These values can be used, in first approximation, to update the costs to current costs, under the assumption that the technological evolutions that produced those cost reductions continued at a similar rate in recent years.

2.2 Onshore wind

The onshore wind installation is based on 1.79 MW turbines, each supported by a tapered steel tower, anchored to the ground through a structurally adequate foundation. The major mechanical components of the turbine, contained in the nacelle at the top of the tower, are the variable-speed generator, transmission, and yaw drive. Each 1.79 MW turbine has a 3-blades rotor with a diameter of 100 m, and a hub height of 80 m, and an active yaw system in the nacelle to keep the rotor facing into the wind. Power from all the turbines in the farm is collected through an underground connection circuit. Each turbine generates power at 575 Volt, and then uses a pad-mounted step-up transformer to increase the voltage to 34.5 kV. At the farm substation, voltage is increased to 115 kV for connection to the grid.

Table 2 – Comparison of the overnight capital cost for wind and solar in 2013 and in 2016

	Overnight cost 2016 ($/kW)	Overnight cost 2013 ($/kW)	Percent chance
On-Shore Wind	1,877	2,354	-25%
Off-shore wind	N/A	6,628	N/A
Solar Thermal	N/A	5,390	N/A
Solar Photovoltaic – Fixed (20 MW)	2,671	4,450	-67%
Solar Photovoltaic – Fixed (150 MW)	N/A	2,671	N/A
Solar Photovoltaic – Tracking (20 MW)	2,644	N/A	N/A
Solar Photovoltaic – Tracking (150 MW)	2,534	N/A	N/A

A breakdown of the capital costs of onshore wind is provided in Table 3. It is noted that the vast majority of the costs (66%) are the mechanical components, with another 10% for the civil construction and 8% for the electrical part. Indirect costs and contingencies are a very small, being 3% and 7% of the total budget, respectively. Likely, the main cause for small indirect costs and contingency main cause is that wind construction projects are simple, and have been erected quickly, while not experiencing substantial cost overruns. Owner's costs are quantified as 6% of total.

Table 3 – Capital cost breakdown for onshore wind facility.

Civil	19,690	10%
Mechanical	122,924	66%
Electrical	15,450	8%
Indirect	6,480	3%
Fees/contingencies	12,500	7%
Owner's costs	10,623	6%
TOT	187,667	100%

O&M costs include the periodic inspection and repairs of equipment, with major maintenance every 5-7 years. Those costs are typically treated as fixed costs.

2.3 Solar photovoltaic

Tracking facilities, as opposed to fixed facilities, are typically mounted on a single-axis tracking PV modules, to maximize the sun exposure. *"Additional BOP components include metal racks* *mounted to tracker components (drive motors, gearboxes, linkages, etc.) supported by foundations, DC wiring, combiner boxes where individual series circuits ("strings") of panels are connected prior to being fed into the inverters, DC-to-AC inverters, AC wiring, various switchgear and step-up transformers, and a control system (partly incorporated into the inverter control electronics) to monitor plant output and adjust the balance of voltage and current to yield maximum power."* (EIA 2016).

Aside from electrical interconnections and step-up transformers, offsite requirements include a connection to a water supply for periodic washing of the modules. Alternatively, water to wash modules can also be purchased off-site. In any case, this cost is included in the fixed O&M cost of Table 1.

The cost breakdown for a fixed 20 MW PV facilities investment is provided in Table 4. It is noted that, while the majority of the costs are attributed to the "Mechanical" category (i.e. the PV modules), a large contribution to the total costs is also due to the electrical connection and equipment, which in the case of PV modules include 500 kW-AC inverters, one for each of the 40 0.5 MW module, that convert the DC power to tri-phase AC at an output voltage typically of 265 Volt to 420 Volt. Afterwards, a generator step-up transformer (GSU) convert the voltage to 13.8 kV or 34.5 kV for larger system, and then to the grid through a circuit breaker.

Table 4 Capital cost breakdown for a 20 MW PV fixed (i.e. non-tracking) facility.

Civil	5239	10%
Mechanical	23987	45%
Electrical	8994	17%
Indirect	2244	4%
Fees/contingencies	4046	8%
Owner's costs	8902	17%
TOT	53412	100%

2.4 Location adjustment

Since the location of interest for this analysis was assumed to be Louisiana, consistently with the location-based work performed in FY17, (EIA 2016) reports that for Louisiana the capital cost of on-shore wind is expected to be 7% lower than the reference value, and the capital cost of PV solar is expected to be 16% lower than the reference value. The difference in adjustment factors could not be explained based on the explanation in the report, since the text explaining the regional adjustments is virtually identical in the wind and PV sections.

2.5 Capacity factors

Average capacity factors for wind and PV solar are reported on a nationwide basis on (EIA 2018). For the entire US, the averages for 2017 was 36.78% for wind and 26.98% for PV solar.

2.6 Lifetimes

Wind turbines typically have a lifetime certified by manufacturers of 20 years (US-DOE, 2015b). The lifetime of a PV panel depends on many factors, such as the irradiation in the plane of the PV array and on the PV system performance (Environment Canada, 2012). Over time, a PV panel degrades and its performance decreases. The lifetime of a panel is usually defined as the time in which the rated power decreases to 80% of its nominal value (Lombardo, 2014). The usual lifespan of solar panels is estimated at 20 to 30 years (Fthenakis et al., 2011; Silicon Valley Toxics Coalition, 2009), and most PV modules are installed with a warranty of 20 years (Lombardo, 2014). Therefore, it is recommended to use 20 years as PV lifetime.

3. Hydrogen storage and transportation

Cost and economic data and parameters for the following components are collected in this Chapter:

- H_2 storage costs;
- H_2 transportation costs.

Throughout the analysis, cost is normalized to a $/kWh basis to allow comparison between different technologies. The energy content of hydrogen was taken on a *lower heating value* (LHV) basis, i.e. the LHV of hydrogen is assumed to be 33.3 kWh/kgH_2. The *lower heating value* of a fuel is defined as the amount of heat released by combusting a specified quantity (initially at 25°C) and returning the temperature of the combustion products to 150°C. This definition assumes that the latent heat of vaporization of water in the reaction products is not recovered.

All costs are escalated to constant 2017 US dollars using the Consumer Price Index (CPI) provided by the US Department of Labor. Because all costs refer to industrial components, other indices, such as the Producer Price Indices (PPI), could be argued to be more appropriate for this analysis. However, PPI indexes are different between different technologies, forcing one to choose which index, among several, would be more appropriate for a specific application. Additionally, because of the short time frame considered, the difference between escalated costs through any inflation index, including CPI or PPI, is small. Therefore, because of its large availability and the ease of use, the CPI was used.

3.1 Hydrogen Storage

Hydrogen can be stored physically as either a gas or a liquid. Storage of hydrogen as a gas typically requires high-pressure tanks. Storage of hydrogen as a liquid requires cryogenic temperatures and tanks, because the boiling point of hydrogen at one atmosphere pressure is -252.8°C (US-DOE, 2018). Hydrogen can also be chemically stored on the surfaces of solids (by adsorption) or within solids (by absorption). A schematic of all types of hydrogen storage systems is shown in Figure 1. A general introduction to the various storage technologies is provided here, while the various technologies are discussed in detail in Sections 2.1 and 2.2.

Compressed gaseous hydrogen (CGH_2) storage in a stationary pressure vessel is the most widely used hydrogen storage technology in the U.S. (Zhang 2012): about 98% of CGH_2 storage hydrogen fueling stations in the U.S. use CGH_2, while worldwide the percentage is 84%.

The key cost drivers for the various on-board hydrogen storage systems analyzed in the reference are reported in Table 5 (Law, 2013).

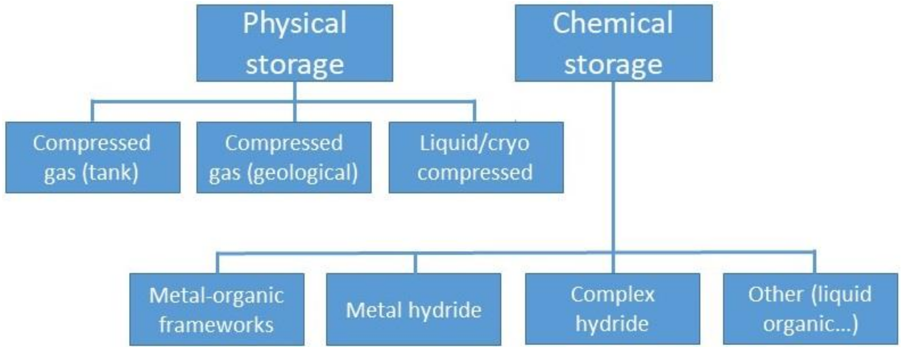

Figure 1 – Types of hydrogen storage systems (US-DOE, 2018)

Table 5 – Summary of On-Board Hydrogen Storage System Key Cost Drivers (Law, 2013)

Hydrogen storage system	Key cost driver
Compressed hydrogen	Carbon fiber, liner
Liquid hydrogen	BOP, assembly and inspection
Cryo-compressed	Carbon fiber, liner and fittings
Sodium Alanate	Catalyzed media, dehydriding accessories
Metal organic framework (MOF)	Carbon fiber, MOF media, assembly and inspection
Activated carbon (AC)	Carbon fiber, AC media

3.1.1. Compressed gas

Compressed gas storage is the simplest solution for storage, requiring only a compressor and a pressure tank. However, the energy density is low, and for higher pressures the capital cost and the operating costs increase (Zhang 2012). Standard compressors can be used for H_2, with some changes to the sealing system to account for the high diffusivity of H_2 molecules. Typically, for H_2 applications, reciprocating compressors are used, although they cost about 50% more than centrifugal compressors (Amos, 1998).

Amos (1998) provides a table of costs (in 1995 dollars) for compressors of different sizes. The reference states that a power law with an exponent of 0.8 can be used for the cost scaling with the compressor's size. The costs from Amos (1998) are reported in Table 6, and the costs as a function of power are plotted in Figure 2, including the best-fit scaling equation showing an exponent of 0.72 (see Figure 2), close to the value of 0.8 reported in Amos (1998). As another source of information on scaling, Peters (2003) reports a scaling exponent for large compressors in the chemical industry of 0.69 for reciprocating compressors and of 0.79 for centrifugal compressors. These values are in line with the numbers in Amos (1998) and fitted in Figure 2. Therefore, it is recommended to use as cost for hydrogen compressors a simple interpolation between the bracketing numbers reported in Table 6, and use an extrapolating exponent of 0.7 for numbers outside the table range. The numbers in Table 6 were escalated from the values of 1995 to 2017 values using a CPI factor of 1.62. Amos (1998) assumes a ratio between compressor power and flow rate of 2.2 kWh/kg.

Table 6 – H_2 Compressor costs as a function of power, from Amos (1998)

Reference	Size (kW)	Unit cost ($\$_{1995}$/kW)	Unit cost ($\$_{2017}$/kW)	Cost ($\$_{1995}$)	Cost ($\$_{2017}$)
Zittel and Wurster 1996	10	6,600	10,692.0	66,000	106,920
Taylor et al 1986	75	2,400	3,888.0	180,000	291,600
Zittel and Wurster 1996	250	660-990 [a]	1,336.5	206,250	334,125
Taylor et al 1986	2,700	863	1,398.1	2,330,100	3,774,762
Taylor et al 1986	3,700	650	1,053.0	2,405,000	3,896,100
Taylor et al 1986	4,500	702	1,137.2	3,159,000	5,117,580
TransCanada Pipeline, Ltd. 1996	28,300	702	1,137.2	19,866,600	32,183,892

[a] take the average: 825 \$/kWh

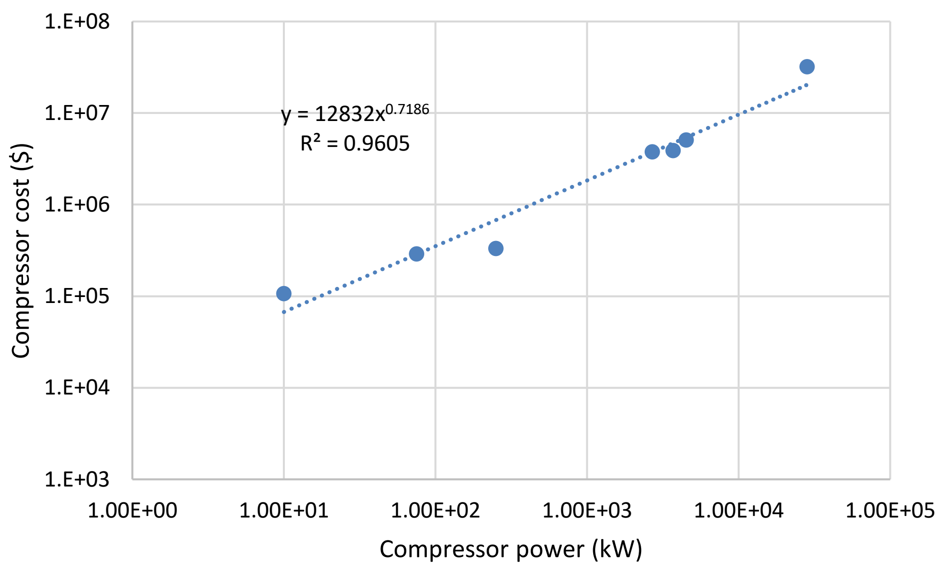

Figure 2 – Cost of H_2 compressors as a function of their power. It is observed that the best-fit equation shows an exponent of 0.72, close to the 0.8 reported in (Amos 1998).

According to Amos (1998), pressure vessel sizing exponents vary from 0.62 to 0.75 based on the storage capacity. Amos (1998) provides a table of costs (in 1996 USD) of hydrogen pressure vessel of different capacities collected from different authors. However, the reference does not report the operating pressures of the different systems. The authors found that the typical capital cost of H_2 gas storage are from \$625 /kgH_2 (i.e. \$18.7 /kWh) to \$2,080 /kgH_2 (\$62.4 /kWh), in 1995 USD. These values, in 2017 USD, correspond to \$30.4 /kWh and \$101.2 /kWh (Table 7).

Table 7 – H_2 pressure vessel costs as a function of capacity, from Amos (1998)

Reference	Size (kgH_2)	Size (kWh)	Design pressure (bar)	Unit cost ($\$_{1995}/kgH_2$)	Unit cost ($\$_{2017\ /kWh}$)
Carpetis 1994	n/a	n/a	n/a	625	30.4
Carpetis 1994	n/a	n/a	n/a	2080	101.2
Oy 1992	0.089	3	n/a	840	40.9
Oy 1992	8.9	296.4	n/a	715	34.8
Oy 1992	8.9	296.4	n/a	1400	68.1
Taylor et al. 1986	550	8,325.0	n/a	840	40.9
Oy 1992	890	29,637.0	n/a	950	46.2
Taylor et al. 1986	1,240	41,292.0	n/a	680	33.1

James (2016) discusses hydrogen small scale storage costs for hydrogen-fueled vehicles with a storage capacity of 5.6 kgH_2 usable hydrogen. Included in the evaluation are pressure vessels (700 bar) produced with five annual manufacturing volumes, ranging from 10,000 to 500,000 systems per year. The compressed hydrogen storage cost for production rates of 10,000 and 500,000 units per year are shown in Table 8. The Balance of Plant (BOP) in storage tanks is the pressure valve, which is typically around \$0.05 /kWh. The total cost for the storage system, including assembly, is \$14.36 /kWh for a production rate of 500,000 units per year. The reference does not mention in what year the cost in USD is expressed. However, since the authors based the economic analysis on reports from 2015, it assumed that the costs are in 2015 USD. The cost of \$14.36 /kWh, escalated to 2017 USD, is \$14.9 /kWh and is much lower than the costs reported by Amos (1998). The reason for this discrepancy is cannot be confirmed: however, between the publication time of Amos (1998) and James (2016), there have been changes in the technology and in the manufacturing of these systems, which resulted in a cost reduction.

Zhang (2012) contains an estimate of manufacturing costs for Steel/Concrete Composite Vessels (SCCV) to store H_2 in stationary installations of compressed gaseous hydrogen (CGH_2). The main issue with stationary storage costs is that standard high strength low-alloy steel suffers from hydrogen embrittlement. The design developed in Zhang (2012) includes a "unique layered steel shell structure" to mitigate this issue. The design is developed for three pressure targets (160, 430 and 860 bar) relevant to H_2 production and delivery infrastructure (a typical primary loop of a PWR is 155 bar, as a reference point). However, the existing hydrogen fueling stations for fuel cell cars in the United States dispense fuel at two pressure levels: H35 (35 MPa or 350 bar) and H70 (70 MPa or 700 bar) In order to be effective, the dispensing vessels have to overmatch the dispensing pressure.

Additionally, there is an issue with fatigue due to pressure cycling the vessel to charge/discharge the hydrogen. Costs in 2011 and DOE cost targets for 2015 (at the time of publication of Zhang (2012)) and for 2020 are shown in

Table 9. SCCV includes an inner steel vessel encased in an outer pre-stressed concrete sleeve. The steel in contact with H_2 is stainless steel, and the other layers are high strength low-alloy structural steel (about 1/4th the cost of stainless steel). The pre-stressed concrete cost less than structural steel. The stationary storage container designed for a pressure of 430 bar and a capacity of 564 kgH_2 has a unit cost of the steel part of \$539 /kgH_2 of H_2 stored (of which about 1/3 is labor and 2/3 is material and equipment costs), or \$16.1 /kWh (Zhang 2012), equivalent to \$17.3 /kWh in 2017 USD. The concrete part has a total direct cost of \$51,000, of which about 1/3 is material and equipment and about 2/3rd is labor. The unit cost per kgH_2 of stored hydrogen is therefore \$90.4 /kgH_2, or \$2.7 /kWh. However, the direct cost of the concrete part needs to be increased by a factor of 1.52 to account for the contingency and profits of the concrete contractor, and by a factor of 1.08 for the site inspection, yielding a total cost of \$4.4 /kWh. This cost, escalated to 2017, is \$4.7 /kWh. The total cost of the tank system (steel and concrete) is then \$22 /kWh.

The authors point out that further costs reductions can be obtained with advanced vessel fabrication technologies such as automated friction stir welding (FSW). This technology substantially reduces the labor needed for assembling and welding and allows to make higher strength steels, with further cost reductions.

Table 8 – Compressed gas storage system costs from James (2016)

	10,000 Units per year	500,000 Units per year
Tank cost	13.23	10.54
BOP cost	$3.48	$9.65
System assembly	0.05	0.05
Total cost	22.94	14.07
Total cost (2017 USD)	23.51	14.36

Table 9 – U.S. DOE's technical targets for stationary gaseous hydrogen storage vessels (for fueling sites, terminals, or other non-transport storage needs), from Zhang, 2012

	Cost (\$ /kgH_2)		
Pressure	FY 2011 Status	FY 2015 Target	FY 2020 Target
160 bar	$1,000	$850	$700
430 bar	$1,100	$900	$750
860 bar	$1,450	$1,200	$1,000

Law (2013) estimated that single tank systems at 350 and 700 bars would cost \$15.3 /kWh and 18.6 \$/kWh (in 2005 USD), respectively, using high-volume manufacturing assumptions (500,000 systems per year). The tank capacity of usable hydrogen for both pressures is 5.6 kgH_2 (6.0 kgH_2 and 5.8 kgH_2 total). The costs are equivalent to \$20.1 /kWh for the 350 bar system and \$23.7 /kWh for the 700 bar system, in 2017 USD. These costs are in line with the ones provided by James (2016), which refers to a similar design, but much higher than those reported by Amos (1998). The main contributor to the costs is the carbon fiber layer (about 75-77% of total costs). Carbon fiber is already mass-produced, and therefore it is not expected to drop in costs significantly with an increase in production. The cost of \$23.7 /kWh is higher than that presented by James (2016) for an equivalent design produced with the same manufacturing rate.

Table 10 – Compressed hydrogen storage system cost from Law (2013)

	350 bar (5.6 kgH_2)		700 bar (5.6 kgH_2)	
	Cost (\$$_{2005}$)	Cost (\$$_{2017\ /kWh}$)	Cost (\$$_{2005}$)	Cost (\$$_{2017\ /kWh}$)
Vessel	2,295	13.0	2,800	15.8
BOP	493	2.8	614	3.5
Final assembly and inspection	59	0.3	59	0.3
Total cost	2,847	16.1	3,473	19.6

Ramsden et al. (2008) reports the cost of hydrogen storage tanks at 2,500 psi (172.3 bar) as \$900 /kgH_2 (\$27 /kWh) in the short term and as \$345 /kgH_2 (\$10.4 /kWh) in the long term. The short term is defined as 2008-2010, while the long term as 2020-2030. The reference does not show the cost in the middle term (2010-2020). Considering a mid-term hydrogen storage cost as the average between the short-term and long-term values, the cost is \$18.7 /kWh. The cost, escalated to 2017 USD, is \$21.5 /kWh.

The cost of those storage systems that are reported together with the design pressure are summarized in Table 11. The average between the costs at 700 bar from James (2016) and Law (2013) is \$19.3 /kWh, while cost of systems in the range of pressure from 172 bar to 430 bar is between \$20.1 /kWh and \$22 /kWh. These values suggest that the cost of pressure tanks seems not to depend on the pressure or on the size of the tank.

The average cost between the data from all authors, including the one reported without specifying the pressure values, is \$38.3 /kWh. However, this range includes data from the late 1990s in the high range from Amos (1998). In the last 20 years, there have been changes and improvements in the technology and therefore some of the highest costs are considered obsolete. Neglecting the data from Amos (1998), the cost average is \$20.4 /kWh (Table 11). This value is considered more accurate to describe the current state of the art, and may be used in the cost estimating process of this storage technology for all values of pressure and size.

Table 11 – Compressed hydrogen storage system costs

Design pressure (bar)	Capacity (kgH_2)	Cost ($\$_{2017}$ /kWh)	
172	85	21.5	Ramsden (2008)
350	5.6	20.1	Law (2013)
430	564	22	Zhang (2012)
700 700	5.6 5.6	14.9 23.7	James(2016) Law (2013)
Average		20.4	

The largest operating cost for compressed hydrogen systems is the electricity to operate the compressors (Amos 1998), which largely depends on the compressor efficiency. Very little data on the real-world performance of compressors in hydrogen is available (NREL, 2014). Hydrogen refueling stations compressors can achieve an isentropic efficiency of about 56% and a motor efficiency of 92% (US-DOE, 2008). In 2012, the DOE's assumptions on hydrogen compressor isentropic efficiency is 65% while the 2020 target is 80% (US-DOE, 2015a). Typical O&M costs for compressed storage are reported in the range \$0.07-1.5 /kgH_2, although the information on the sizes of the plants for which these numbers are applicable was not found. Therefore, it is recommended to use an average value for the O&M costs of \$0.8 /kgH_2, or \$0.024 /kWh, which is equivalent to \$0.037 /kWh in 2017 USD.

3.1.2 Cost summary of compressed gas H_2 storage

Compressed hydrogen storage system are mainly made of the compressor and the pressure tank. For the compressor, it is suggested to use a simple interpolation between the bracketing numbers reported in Table 12, and use an extrapolating exponent of 0.7 for numbers outside the table range. The size of the compressor depends on the desirable flow rate of the storage system. The constant ratio between power and flow rate of 2.2 kWh/kg should be used.

For the pressure tank, a specific capital cost of \$20.4 /kWh should be used.

Regarding O&M, it is recommended to use a cost of \$0.037 /kWh.

Table 12 – Compressor costs

Size (kW)	cost ($\$_{2017}$)
10	106,920
75	291,600
250	334,125
2,700	3,774,762
3,700	3,896,100
4,500	5,117,580
28,300	32,183,892

3.1.3 Underground storage

Underground storage is the most economical means of storage for large quantities of hydrogen. In storing hydrogen in geologic formations the main issue is the availability of a suitable geologic formation where the storage is needed. Currently, in the US H_2 is stored in solution-mined salt domes along the Gulf Coast. As for any gas, an additional issue involving underground storage is the "cushion gas", which is the gas that remains in storage at the end of the discharge cycle. For H_2, the "cushion gas" is considerable, up to 50% of the stored gas (Amos 1998).

As reported by Amos (1998), Taylor et al. (1986) estimated solution mining costs at \$23/m^3 (\$0.66/ft3), while hard rock mining costs were estimated at \$34-\$84/m3 (\$1.00-\$2.50/ft3) depending on the depth. Amos (1998) found prices in the range from \$2.5 /kgH$_2$ (\$0.07 /kWh) to \$7 /kgH$_2$ (\$0.20 /kWh, in 1995 USD) for storage capacities between 8.9 and 890 kgH$_2$. The range, escalated to 2017 USD, is \$0.12-0.34 /kWh. Amos (1998) also reports a cost of \$18.9 /kgH$_2$ (\$0.57 /kWh, in 1995 USD), extracted from Taylor (1986), without reporting the size of the storage. The cost, converted to 2017 USD, is \$0.92 /kWh.

The cost as developed by the ANL H$_2$A Delivery Component Models, (Argonne National Laboratory, 2009; 2009a) is 0.3 \$/kWh for a 41,000 kgH$_2$ usable storage capacity. However, this value is referred to the kWh of electricity produced, and not to the capacity (in kWh) of storage and, therefore, it is not comparable to the values from Amos (1998). This value was used in Steward (2009) as the reference cost, and is equivalent to 0.35 \$/kWh in 2017 USD.

Lord et al. (2011) developed a prototype analytical framework to estimate the major costs of different underground storage options, namely salt caverns, depleted oil and gas reservoirs, aquifers, and hard rock caverns. The main parameters of each storage design is shown in Table 13. It is important to note that the depleted oil and gas reservoirs and aquifers require higher percentages of cushion gas.

Table 13 – Geological site design characteristics (Lord et al., 2011)

	Salt Cavern	Depleted Oil & Gas Reservoir	Aquifer	Hard Rock Cavern
Formation Pressure (psi)	2,000*	1,995	1,995	2,000
Void Volume (m3)	580,000	676,940	676,940	580,000
Formation Temp. (K)	310.9	315.1	315.1	310.9
Well Depth (ft)	3,800	4,604	4,604	3,800
Working Gas (tonnes H_2)	6,238	7,164	7,164	6,238
Cushion Gas (tonnes H_2)	1,871	3,582	3,582	1,871

The cost inputs used in the (Lord et al., 2011) analysis are shown Table 14, while the resulting capital costs are presented in Table 15, along with the costs normalized per storage capacity (both in kgH_2 and in kWh). The storage capacity used here is the net capacity, which only includes the amount of working gas (not the cushion gas). The cost per unit of kWh, escalated to the value of 2017 USD, is also shown in the table.

Table 14 – Cost analysis inputs (Lord et al., 2011)

	Salt Cavern	Depleted Oil & Gas Reservoir	Aquifer	Hard Rock Cavern
Compressor Costs Total (2007 US$)	27,539,480	18,359,654	18,359,654	27,539,480
Full Pipeline Costs ($/tonne)	2.26	3.22	3.22	2.26
Full H_2 Wells Cost ($/tonne)	46.27	10.55	47.45	556
Full H_2 surface piping ($/tonne)	0	0	0	0

The least expensive underground storage solution is in depleted oil & gas reservoir, followed by aquifer and salt cavern. The most expensive solution is for hard rock cavern, mainly due to the higher well drill cost.

Operating cost consists of energy and maintenance costs related to compressing the gas into underground storage and possibly boosting the pressure coming back out. O&M costs of underground H_2 storage was estimated in Amos (1998) at $1-3.9 /$kgH_2$, or $0.03-0.12 /kWh (1995 USD). Converting these values to 2017 USD, we obtain the range $0.04-0.17 /kWh. Since there are no specifications of the plants for which that these values are valid, it is recommended to use the average value of $0.11 /kWh.

Table 15 – Underground storage capital costs

	Salt Cavern	Depleted Oil & Gas Reservoir	Aquifer	Hard Rock Cavern
Capital cost (2007 USD)	63,254,547	40,106,938	40,999,458	89,644,020
$ /kgH_2 (2007 USD)	10.140	5.598	5.723	14.371
$/kWh (2007 USD)	0.305	0.168	0.172	0.432
$/kWh (2017 USD)	0.37	0.20	0.21	0.52

3.1.4 Cost summary of underground H_2 storage

In the range 8.9-890 kgH_2, the conservative cost of $0.34 /kWh from Amos (1998) can be used, for all types of geological formation. It is recommended to use the capital costs shown in Table 16 for the respective capacities and above, based on the type of geologic formation. For storage sizes between 890 kgH_2 and the ones in Table 16 a simple interpolation may be used. Regarding O&M, it is recommended to use the mid-range value of $0.11 /kWh.

Table 16 – Capital costs summary

Cost (2017 USD)	Salt Cavern	Depleted Oil & Gas Reservoir	Aquifer	Hard Rock Cavern
Capital cost	0.37	0.20	0.21	0.52
Capacity (tonnes)	6,238	7,164	7,164	6,238

3.1.5 Liquid hydrogen storage

H_2 boiling (and liquefaction point) is 20K (-253C). The cooling process for H_2 is more complicated than for most other gases. Taking N2 as an example, N2 cools upon expansion at room temperature (after being compressed and having passed through a heat exchanger), while H_2 does not cool upon expansion but rather increases in temperature. In both the Linde and the Joule-Thompson process, H_2 is compressed, then cooled in a heat exchanger, and then it is expanded through a throttle valve. Upon expansion, some liquid is produced, while un-liquefied but cooled gas is returned to the compressor. For the process to work with H_2, the gas must be cooled below its "inversion" temperature at 202K (-71.15C). The precooling is achieved through heat exchanging with liquid N2 before the expansion valve. Alternatively, a turbine expansion instead of a valve will always cool a gas, regardless of its inversion temperature, but the turbine can only be used to cool the gas, not to liquefy it, to avoid damage to the blades. The ideal work to liquefy H_2 is 3.228 kWh/kgH_2, while that to liquefy Nitrogen is about 0.207 kWh/kgH_2. More complex liquefaction processes used in practice include the Dual-Pressure Linde Process, the Claude Cycle, the Dual-Pressure Claude Cycle, and the Haylandt Cycle.

In liquid form at 20K, the H_2 is almost entirely para-hydrogen, while at room temperature it is only 25% para-hydrogen. If liquefied without a previous change from ortho to para-hydrogen, the ortho-hydrogen will eventually be converted into the para form in an exothermic reaction. Therefore, it is important to covert the H_2 entirely to para-hydrogen before liquefaction. The conversion can be done using catalysts. The amount of H_2 that evaporates during the process can be vented, allowing it to build pressure in the tank, or returned to the liquefaction process without losses.

Generally, using liquid H_2 storage for small amounts of H_2 is not cost competitive, because of the large capital cost of the liquefaction equipment and the high cost of the cryogenic storage containers.

Liquid hydrogen is stored in cryogenic containers at a pressure slightly higher than ambient pressure. In order to achieve the insulation requirements, the space between the double wall is evacuated, and multiple layers of reflective heat shields are put between the walls of the vessels (typically aluminized plastic Mylar or perlite (colloidal silica), which is cheaper). Some large storage containers have an outer wall with the space filled with liquid nitrogen.

Generally, liquid H_2 storage tanks are spherical, as the sphere has the lowest surface to volume ratio. Cylindrical tanks are cheaper to manufacture, therefore they are also occasionally used. Liquid H_2 storage tanks can be constructed in different sizes, typically from 100 kgH_2 to 230,000 kgH_2 (the latter being the largest in the world owned by NASA (Amos 1998)).

For liquid hydrogen storage, the most expensive component is the multi-layer vacuum isolation (MLVI), accounting for about 17-25% of system costs (Law, 2013). Law (2013) presented two configurations of hydrogen storage for automotive applications. The cost breakdown of a 5.6 kgH_2 and a 10.4 kgH_2 liquid hydrogen storage systems are shown in Table 17. The costs were calculated assuming a production rate of 500,000 units per year. The designs are based on configurations developed in collaborations with Argonne National Laboratory (ANL) and Lawrence Livermore National Laboratory (LLNL). The mass flow rate of the system was found in ANL (2009b), and it is 1.5 kgH_2/min (50.0 kWh/min). Since the flow rate is the same, the cost of BOP and final inspection is the same for both designs. The only cost difference between the two configurations is the vessel cost, which is \$4.7 /kWh and \$3.8 /kWh (escalated to 2017 USD) respectively.

Liquid H_2 containers are low pressure, but their cost is high because of the cryogenic requirements. The cost breakdown is estimated to be 10% planning, 60% equipment and 30% construction (Amos, 1998). The recommended exponent for the cost scaling law is 0.7 (Amos, 1998). As shown in Table 18, unit cost vary from \$18/ kgH_2 (\$0.5 /kWh, equivalent to \$0.87 /kWh in 2017 USD) for 300 MTH_2 to \$700 kgH_2 (\$21 /kWh, equivalent to \$34.05 /kWh in 2017 USD) for a very small vessel containing 0.089 kgH_2 (Amos, 1998). However, this value is inconsistent with cost of another vessel of the same capacity (8.9 kgH_2), which is \$1.02 /kWh (escalated to 2017 from Amos (1998)). Amos (1998) estimates that the system costs will likely range (95 percent confidence) from \$9 to \$13 /kWh (\$9.5-13.7 /kWh in 2017 USD) for the 5.6 kgH_2 system and \$6 to \$9 /kWh (\$6.3-9.5 /kWh in 2017 USD) for the 10.4 kgH_2 system.

Table 17 – Liquid hydrogen storage system cost from Law (2013)

	5.6 kgH_2	10.4 kgH_2

	Cost ($\$_{2005}$)	Cost ($\$_{2017}$ /kWh)	Cost ($\$_{2005}$)	Cost ($\$_{2017}$ /kWh)
Vessel	694	4.7	1,023	3.8
BOP	543	3.7	543	2.0
Final assembly and inspection	235	1.6	235	0.9
Total cost	1,472	10.0	1,352	5.0

Table 18 – Liquid hydrogen vessel costs as a function of capacity, from Amos (1998)

Reference	Size (kgH_2)	Size (kWh)	Unit cost ($\$_{1995}/kgH_2$)	Unit cost ($\$_{2017}$ /kWh)
Carpetis 1994	n/a	n/a	n/a	50.2
Carpetis 1994	n/a	n/a	n/a	25.3
Oy 1992	0.089	2.96	700	34.1
Oy 1992	8.9	296.4	490	23.8
Oy 1992	8.9	296.4	36	1.8
Oy 1992	890	29,637	21	1.0
Taylor et al 1986	270	8,991	450	21.9
Taylor et al 1986	300,000	$9.99\ 10^6$	18	0.9

Figure 3 shows the costs from Table 17 and Table 18 in the range 2.96-8,991 kWh, where the costs from Carpetis (1994) were omitted, as they were not associated to a specific size. The line, representing the average cost, is also plotted. Since the costs from the different sources vary considerably, it is recommended to use the average cost of \$20.7 /kWh in the estimating process.

Another important cost in storing liquid hydrogen is that of the liquefaction plant, which typically have sizes of 100-2300 kgH_2/hour (Amos, 1998). Amos (1998) reports sizing exponents in the range 0.6-0.7. Costs collected by Amos (1998) from different sources are shown in Table 19. Costs range from \$776 /kWh/h to \$5,772.8 /kWh/h.

The first three values in the table (there is no information on the size of the liquefaction plant from Cuoco et al. 1995) are plotted in Figure 4, along with their power function fit. The exponent resulting from the fit is equal to 0.58, close to the lower bound of the range (0.6) reported by Amos (1998). However, since only three values are available, it is recommended to use a linear interpolation between the costs in the range 5,661-116,550 kWh. For values outside the range, it is suggested to scale the cost using an exponent of 0.6.

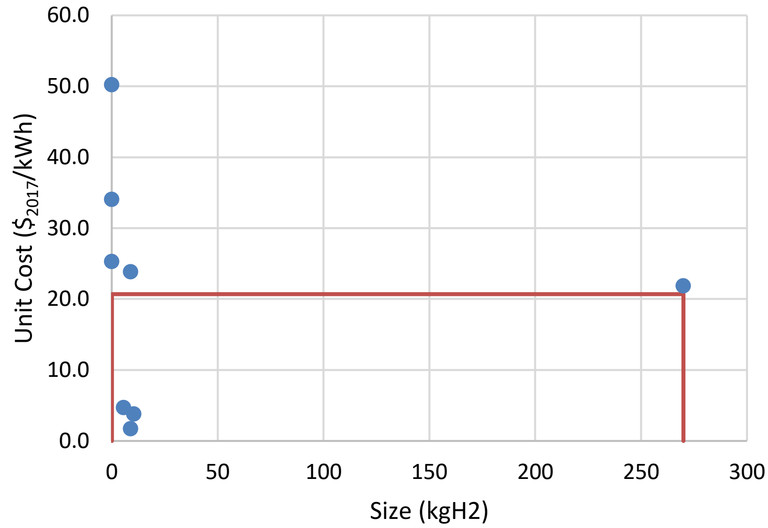

Figure 3 – Liquid hydrogen vessel costs (2017 USD)

Table 19 – Liquefaction plants as a function of size, from Amos (1998)

Reference	Size (kgH_2/h)	Size (kWh/h)	Unit cost ($\$_{1995}$/$kgH_2$/h)	Unit cost ($\$_{2017\ /kWh}$/h)	Unit cost ($\$_{2017}$/h)
Zittel and Wurster 1996	170	5,661	118,000	5,722.8	32,396,900
Taylor et al. 1986	380	12,654	31,750	1,539.8	19,484,975
Taylor et al. 1986	1,500	116,550	25,600	1,241.6	144,704,000
Cuoco et al. 1995	n/a	n/a	16,000	776.0	-

The largest operating cost for this type of storage is the electricity to operate the liquefaction plant, but small amounts of liquid nitrogen and of cooling water are also needed. A typical O&M cost for a liquid H_2 storage plant was found to be \$0.08 /kgH_2 for compression equipment and utilities, \$0.13 /kgH_2 for the liquid hydrogen tank, and \$1 /kgH_2 for electrical energy Amos (1998), since the liquefaction power requirement varies in the range of 8-13 kWh/kgH_2. Assuming a cost of 5 cents/kWh as a typical industrial purchased electricity cost, the electricity requirements are \$0.40-0.65 /kgH_2: therefore, the mentioned cost of \$1 /kgH_2 is conservative, and likely assume a higher electricity cost (since not all H_2 liquefaction plants will have access to industrial-price electricity), and likely may include allowance for the efficiency of the liquefaction equipment and for the H_2 boil-off rate. Overall, the O&M cost of liquid H_2 storage system is \$1.21 /kgH_2, or \$0.036 /kWh. In 2017 USD, the cost is \$0.062 /kWh.

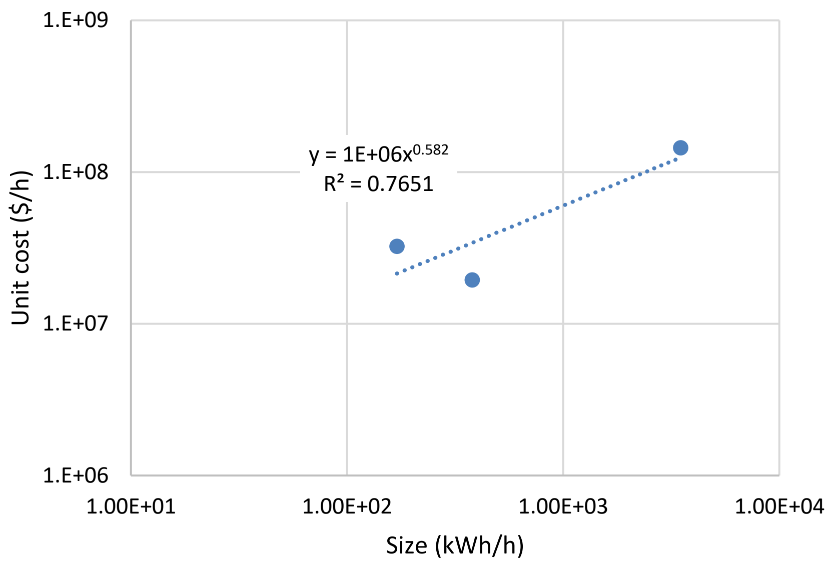

Figure 4 – Power function fit between liquefaction plant costs

For the storage system for automotive applications presented in Law (2013), Argonne and TIAX performed a cost analysis of the refueling cost plant, which is shown in Table 20. The liquefaction cost is \$1.56 /kgH_2, equivalent to \$0.05 /kWh in 2017 USD. For the liquefaction plant, the authors assumed a cost of \$474 million for two liquefier, whose capacity was not specified, and a capital investment of \$134 million for production through a SMR central plant. Under these assumptions, hydrogen refueling would cost \$4.57 /kgH_2, or \$0.14 /kWh. In 2017 USD, the refueling cost is \$0.16 /kWh.

Table 20 – Liquid hydrogen refueling cost (\$/kgH_2), delivered to the vehicle (ANL, 2009b)

	Production	Liquefaction	Storage	Tank	Station
Capital	0.22	0.85	0.55	0.06	0.21
O&M	1.20	0.21	0.24	0.15	0.22
Fuel	0.13	0.50	-	0.01	0.02
Total	1.55	1.56	0.79	0.22	0.45

3.1.6 Cost summary of liquid H_2 storage

For the cryogenic tank, it is recommended to estimate the cost using the specific cost of \$20.7 /kWh. For the liquefaction plant, we suggest to interpolate the costs from Table 21.

The O&M cost of liquid H_2 storage systems is \$1.2 /kgH_2, or \$0.036 /kWh. In 2017 USD, the cost is \$0.062 /kWh.

Table 21 – Summary of main liquefaction plant capital costs

Reference	Size (kWh/h)	Unit cost ($_{2017\ /kWh}$/h)
Zittel and Wurster 1996	5,661	5,722.8
Taylor et al. 1986	12,654	1,539.8
Taylor et al. 1986	116,550	1,241.6

3.1.7 Cryo-compressed hydrogen

Cryo-compression consists of storing hydrogen at cryogenic temperatures (e.g. < ~ 100 K) and at high pressure in high pressure vessels (Petipas, 2014). Cryo compressed hydrogen differs from liquid hydrogen as it is compressed and stored in higher pressures containers (up to 700 bars as compared to a couple of bars for liquid hydrogen). The main advantage of cryo-compression storage over liquid storage is that the tank is allowed reach higher pressures so that the hydrogen boil-off does not take place or is delayed in time (Stolten, 2016). For cryo-compressed hydrogen storage, the most expensive component is the carbon fiber, similarly to the standard tank systems (Law, 2013). Table 22 shows costs of cyo-compressed hydrogen storage systems from Law (2013). The two systems have capacities of 5.6 kgH_2 and 10.4 kgH_2 and a working pressure of 272 atm.

Table 22 – Cryo-compressed hydrogen storage system cost from Law (2013)

	5.6 kgH_2		10.4 kgH_2	
	Cost ($_{2005}$)	Cost ($_{2017\ /kWh}$)	Cost ($_{2005}$)	Cost ($_{2017\ /kWh}$)
Vessel	1,265	8.6	1,937	7.1
BOP	705	4.8	705	2.6
Final assembly/ inspection	235	1.6	235	0.9
Total cost	2,205	15.1	2,877	10.6

With a confidence level of 95%, Law (2013)estimate the cost in the range $11-16 /kWh ($14.0-20.4 /kWh in 2017 USD) for the 5.6 kgH_2 system and in the range $8-11 /kWh ($10.2-14.0 /kWh in 2017 USD) for the 10.4 kgH_2 system. The total costs, in 2017 USD, are $2,815.8 and $3,671.0, for the 5.6 kg$H_2$ and the 10.4 system respectively. The interpolation through a power function of the total costs gives a scaling exponent of 0.43. The interpolating function in shown in Figure 5.

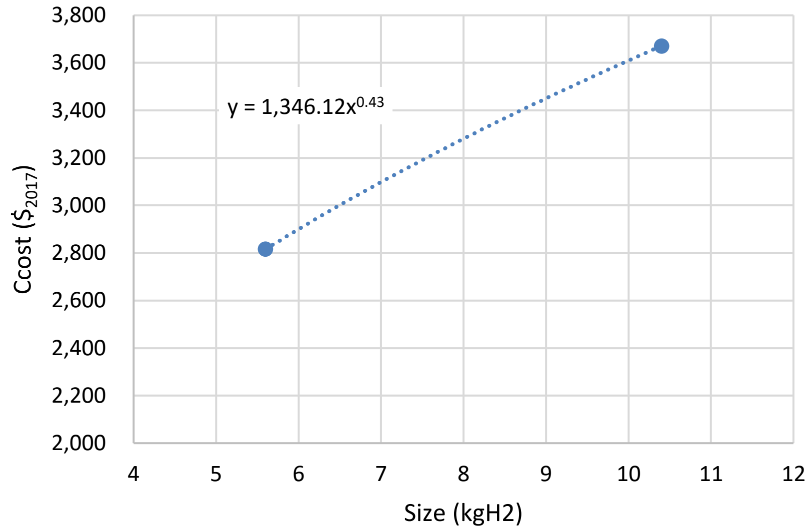

Figure 5 – Cryo-compressed hydrogen storage cost trendline

Cost data for large-scale cryogenic hydrogen storage was not found in literature. In the cost estimate, we recommend to use a simple interpolation between the vessel costs in the range 5.6 kgH_2-10.4 kgH_2. The cost of BOP ($705) and final assembly/inspection ($235) has to be added. For systems outside the size range, we suggest to scale the cost using a scaling function with an exponent equal to 0.43.

Operating costs were not found in literature. However, as the operation stage consist of liquefying and compressing hydrogen, we can estimate that the operating cost is the sum of O&M cost of compressed gas storage ($0.037 /kWh) and O&M cost of liquid storage ($0.062 /kWh). The O&M cost is then $0.099 /kWh, which is approximated as$0.1 /kWh.

3.1.8 Cost summary of cryo-compressed H_2 storage

For the cost estimate of a storage tank in the range 5.6-10.4 kgH_2 it is recommended to scale the costs through the interpolation of the values in Table 23. The cost needs to be increased by $940, to represent the BOP and the final assembly/inspection cost. For costs outside the range, we recommend to scale the total cost (shown in Table 24) through a power function with an exponent of 0.43. The O&M cost is $0.1 /kWh.

Table 23 – Cryo-compressed hydrogen storage cost summary (tank and BOP cost)

Size (kgH_2)	Tank cost ($\$_{2017}$ /kWh)	BOP cost ($\$_{2017}$)
5.6	7.1	940
10.4	3.2	940

Table 24 – Cryo-compressed hydrogen storage cost summary (total cost)

Size (kgH_2)	Total cost ($\$_{2017}$ /kWh)
5.6	15.1
10.4	10.6

3.1.9 Pipeline storage

Pipelines that are several miles long have very large volumes. Small changes in pressure of the pipeline can be used to store large amount of H_2, thus avoiding the extra cost of dedicated storage. Storage in pipeline by slight changes in pressure has a zero cost, as long as the specification of the system (pipelines, compressors, valves) etc. are not exceeded (Amos, 1998).

3.1.10 Metal hydride storage

Metal hydride typically bond H_2 at or below atmospheric pressure, and release the H_2 when heated at higher pressure. Figure 6 shows a typical pressure/H_2 mass charge discharge cycle diagram (Amos, 1998).

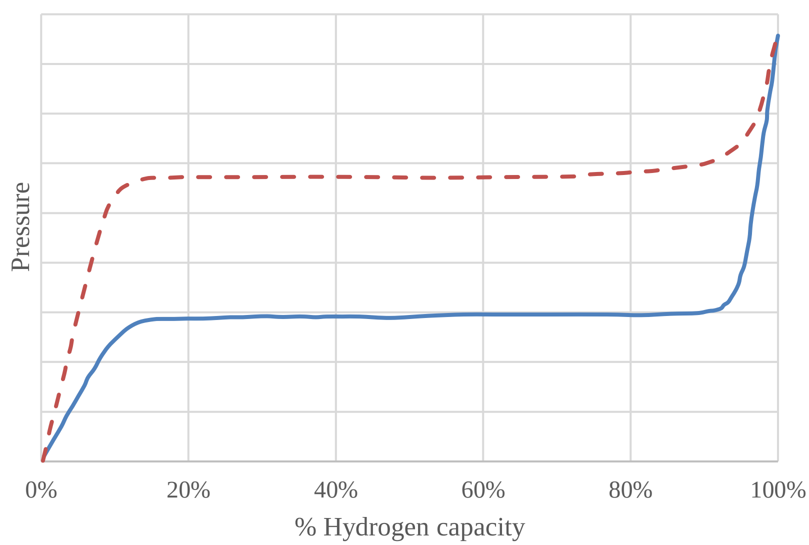

Figure 6 – Typical hydride charge/discharge schematic: charge at low pressure and temperature, discharge at higher pressure/temperature (Amos, 1998)

With this wide range of pressures and temperatures, the construction of the storage unit becomes a challenge. The vessel containing the hydride must be pressurized and contain a sufficient heat exchange area to allow rapid heat transfer for charging and discharging the hydride.
Metal hydrides only store 2-6% in mass of hydrogen by weight. The metal hydride storage medium has a high volumetric density but low weight density, in terms of H_2 stored. In other words a typical metal-hydride storage tank will be relatively compact but rather heavy.

The metal hydride alloy must also be structurally and thermally stable to withstand numerous charge/discharge cycles. Some hydrides can also be poisoned by carbon dioxide, sulfur compounds, or water (Amos 1998).

Metal hydride can also be successfully used to *purify* gas streams of hydrogen and other materials. For example, Au et al. (1996) fluxed a 50% mix of H_2 in an ammonia waste stream over a low-temperature metal hydride, recovering 76% of high purity hydrogen (99.999% H_2). Cold water was used as coolant for the hydride and warm water was used for the desorption (H_2 recovery) process (Au et al. 1996).

The equipment needed for metal-hydride storage includes the storage material, a pressure vessel, and a heat exchanger for cooling and heating during adsorption and desorption, respectively. Additionally, for certain hydrides a compressor may be needed. Amos (1998) presents costs for metal hydride units with sizes between 0.036 kgH_2 and 890 kgH_2 (Table 25). Costs ranges from \$820 /kgH_2 (i.e. \$24.6 /kWh, \$39.9 /kWh in 2017 USD) for a unit in the 0.089-8.9 kgH_2 range to \$60,000 /kgH_2 (\$2,918.9 /kWh in 2017 USD) for a unit of 0.036 kgH_2. The majority of the costs are for the storage material, so generally there are little economies of scale for hydride storage.

The cost of systems in the size range between 0.89 kgH_2 and 8.9 kgH_2 are shown in Figure 7, along with the uniform distribution representing the average cost of \$225.2 /kWh. The first two cost values in Table 25, as the size of the design were not available, were plotted at a size of 0 kgH_2.

Table 25 – H_2 pressure vessel costs as a function of capacity, from Amos (1998)

Reference	Size (kgH_2)	Size (kWh)	Unit cost (\$$_{1995}$/$kgH_2$)	Unit cost (\$$_{2017}$ /kWh)
Carpetis 1994	n/a	n/a	1,765	85.9
Carpetis 1994	n/a	n/a	2,100- 2,600	102.2-126.5
Hydrogen Components Inc. 1997	0.036	1.2	60,000	2,918.9
Oy 1992	0.089	3.0	820	39.9
Oy 1992	8.9	296.4	1,300	63.2
Oy 1992	8.9	296.4	1,400	68.1
Oy 1992	890	29,637	1,800	87.6
Zittel and Wurster 1996	2.7	89.9	3,150-12,200	153.2-593.5
Zittel and Wurster 1996	0.089	3.0	6,000-22,000	291.9-1,070.3
Zittel and Wurster 1996	0.89	29.6	3,000-11,000	145.9-535.1
Zittel and Wurster 1996	8.9	296.4	2,200-8,200	107.0-398.9

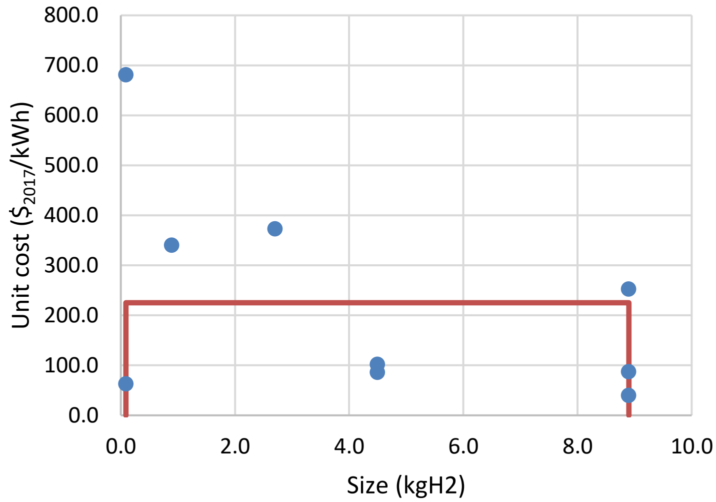

Figure 7 – Metal hydride hydrogen storage costs (0.089-8.9 kgH_2) from Amos (1998)

As the figure do not show a strong cost dependence on the storage size, it is suggested to use the average value of \$225.2 /kWh for systems in the range of capacity between 0.089 kgH_2 and 8.9 kgH_2. For sizes in the range 0.036-0.089 kgH_2, the cost can be linearly interpolated with the cost of \$2,918.9 /kWh at 0.036 kgH_2, while sizes between 8.9 kgH_2 and 890 kgH_2, it can be interpolated with the value of \$80.63 /kWh at 890 kgH_2. The interpolation value are summarized in Table 26.

Table 26 – Interpolation costs for metal hydride storage

Size (kgH_2)	Cost (\$/kWh)	Cost (\$)
0.036	2,918.90	3,499
0.089	225.20	667
8.9	225.20	66,743
890.0	87.60	2,596,201
1,240	80.63	3,329,370

An exponent equal of 0.75 can be used to interpolate the absolute costs from Table 26 (Figure 8). It is therefore suggested to interpolate costs of storage with capacity outside the range 0.036-1,240 through the power function.

Typical heating and cooling requirements for hydride storage is between 9.3 and 18.6 MJ/kgH_2 (2.6 to 5.2 kWh/kgH_2). The total O&M cost of hydride storage is typically about \$0.65 /kgH_2, or \$0.02 /kWh. In 2017 USD, the O&M cost is \$0.03 /kWh.

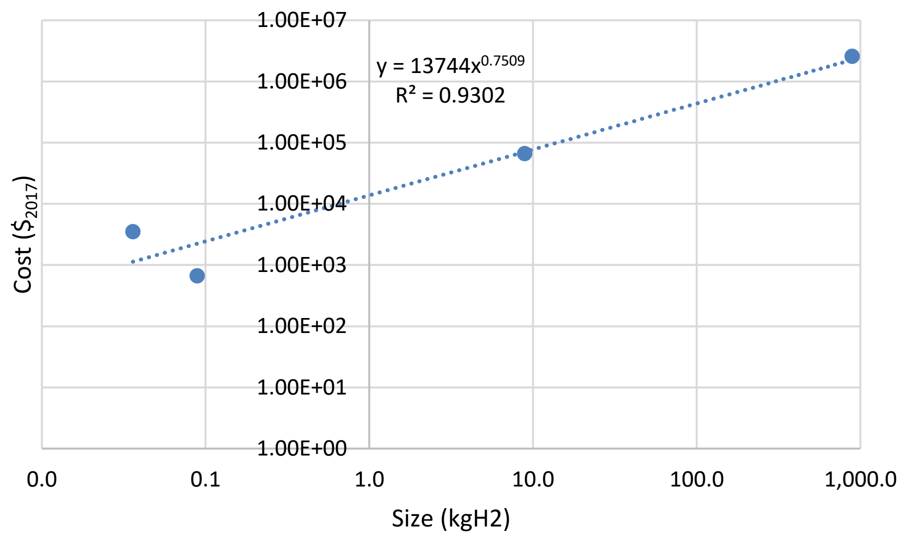

Figure 8 – Interpolation function for metal hydride storage

3.1.11 Cost summary of H_2 metal hydride storage

For designs in the size range 0.089-8.9 kgH_2 it is recommended to use the capital cost of $225.2 /kWh. For systems in the range 0.036-0.089 kgH_2 it is suggested to simply interpolate with the value of $2,918.9 /kWh at 0.036 kgH_2. For systems in the range 0.089-890 kgH_2 it is recommended to interpolate with the value of $87.6 /kWh at 890 kgH_2. For storage capacities outside the range 0.036-1,240, a power function with an exponent of 0.75 should be used.
O&M costs are $0.02 /kWh.

3.1.12 Metal-organic storage

Metal–organic frameworks (MOFs) are a class of crystalline materials consisting of metal ions linked together by organic ligands, resulting in a high porosity material (Hirscher, 2007). Due to the high number of pores and surface area, MOFe have the advantage, over Metal hydride storage of allowing a higher hydrogen uptake in a given volume. James (2016) evaluated the cost of "small scale" metal-organic systems for vehicle applications, with a capacity of 6.22 kgH_2 stored and 5.6 kgH_2 usable. The author considered two systems, which differ in the form of the Metal Organic Framework (MOF) absorbent and the internal heat transfer manifold. Assuming a production rate of 500,000 systems per year, the cost of the first system (Hexcell) is $3,051.65, equivalent to $16.4 /kWh, all in 2007 USD. Regarding the second system (MATI), assuming the same production rate, the cost is $2,495, or $13.4 /kWh. Considering a CPI factor of 1.22 between 2007 and 2017, the costs in 2017 USD are $20.0 /kWh for Hexcell and $16.3 /kWh for MATI.
Law (2013) studied the factory cost of two metal-organic frameworks, MOF-5 and MOF-177. The cost of MOF-177 was estimated for two capacities, 5.6 kgH_2 and 10.4 kgH_2, and are shown in

Table 27. The cost of the 5.6 kgH_2 system is \$19.9 /kWh, and the cost of the 10.4 kgH_2 system is \$28.2 /kWh, 24% lower than the 5.6 kgH_2 one.

According to the multi-variable sensitivity analysis results, the factory cost of the MOF-177 systems will likely range, with a 95% confidence, between \$15 and \$20 /kWh for the 5.6 kgH_2 system and between \$11 and \$15 /kWh for the 10.4 kgH_2 system. The interpolation through a power function of the two system costs, shown in Figure 9, gives a scaling exponent of 0.57.

Table 27 – MOF-177 storage system cost from Law (2013)

	5.6 kgH_2		10.4 kgH_2	
	Cost ($\$_{2005}$)	Cost ($\$_{2017}$ /kWh)	Cost ($\$_{2005}$)	Cost ($\$_{2017}$ /kWh)
MOF-177	448	3.1	832	3.1
Vessel	1,411	9.6	2,245	8.3
BOP	814	5.6	814	3.0
Final assembly and inspection	235	1.6	235	0.9
Total cost	2,908	19.9	4,126	15.2

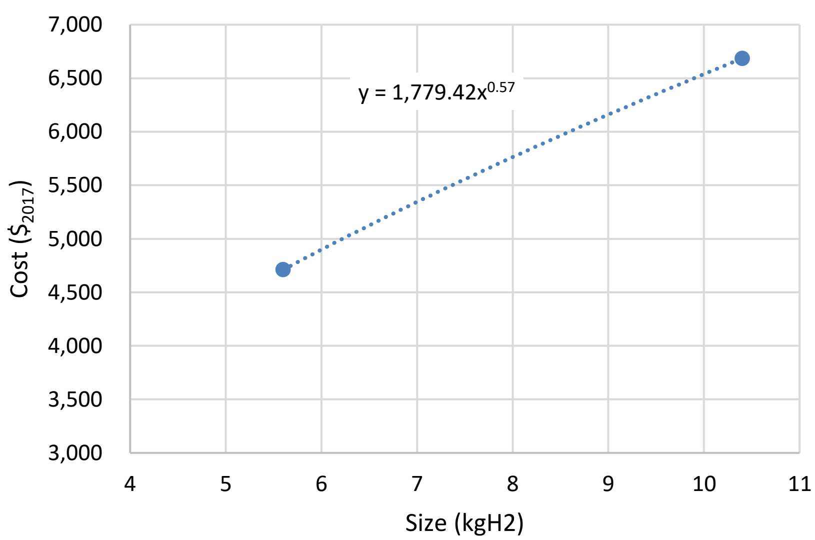

Figure 9 – MOF-177 hydrogen storage cost trendline

MOF-5 has a capacity of 5.6 kgH_2 and a cost of \$2,288. Escalated to 2017 USD, the cost is \$15.6/kWh. The cost range (with 95% confidence) is \$12-16 /kWh that, using a CPI factor of 1.27, is \$15.3-20.4 /kWh in 2017 USD.

Table 28 – MOF-5 storage system cost from Law (2013)

	5.6 kgH_2	
	Cost ($\$_{2005}$)	Cost ($\$_{2017}$ /kWh)
MOF-5	168	1.1
Vessel	1,039	7.1
BOP	814	5.6
Final assembly and inspection	267	1.8
Total cost	2,288	15.6

The cost average of all 5.6 kgH_2 systems (Hexcell, MATI, MOF-5, and MOF-177) is \$17.95 /kWh (Table 29). For MOF-177, the configuration with 10.4 kgH_2 has a cost decrease of 24% in respect to the one with 5.6 kgH_2 capacity. We can assume a similar cost decrease of the "average" 5.6 kgH_2 configuration, as the size is increased to 10.4 kgH_2. Using this approach, the cost of the 10.4 kgH_2 design, representing the average between all the 5.6 kgH_2 technologies, would be \$13.7 /kWh. Therefore, we recommend to use a linear interpolation between \$17.9 /kWh and \$13.7 /kWh for sizes in the range 5.6-10.4 kgH_2 for systems outside the size range, an exponent of 0.57 can be used, which derives from the power function fit shown in Figure 9.

Table 29 – Cost average between the metal-organic systems technologies (5.6 kgH_2)

	Size (kgH_2)	Cost ($\$_{2017}$ /kWh)
Hexcell	5.6	20.0
MATI	5.6	16.3
MOF-177	5.6	19.9
MOF-5	5.6	15.6
Average		17.95

Operating costs for metal organic systems were not found. Therefore, the same costs of metal hydride storage (\$0.02 /kWh) can be assumed for this technology.

3.1.13 Cost summary of H_2 metal-organic storage

For the cost estimate of a storage tank in the range 5.6-10.4 kgH_2 it is recommended to scale the costs through the interpolation of the values \$17.9 /kWh and \$13.7 /kWh. Outside the range, we recommend to scale the cost using an exponent of 0.57.

O&M costs can be estimated as \$0.02 /kWh.

3.1.14 Complex hydride storage

Law (2013) evaluated Sodium alanate (NaAlH4) as an option for a small size (5.66 kgH_2) hydrogen storage unit. Sodium alanate is a medium-temperature complex hydride with high reversible hydrogen content at moderate conditions (Law 2013). The system cost for NaAlH4 system is estimated to be \$11 /kWh, which escalated with CPI, is equivalent to \$11.6.kWh in 2017 USD. The main cost contributors for the compressed hydrogen storage systems are the tank and BOP components, whereas in the NaAlH4 system, both costs are reduced by more than half. However, for the NaAlH4, the Sodium Alanate itself is the major cost item, contributing to about 40% of the total cost.

Operating costs were not found in literature. However, the same energy requirements as those of metal hydride systems can be assumed. Under this assumption, O&M costs are \$0.02 /kWh.

Table 30 – Complex hydride storage system cost from Law (2013)

	5.6 kgH_2	
	Cost ($\$_{2005}$)	Cost ($\$_{2017\ /kWh}$)
Catalyzed Media	168	1.1
Tank	1,039	7.1
Dehydriding Sub-System		
BOP	814	5.6
Final assembly and inspection	267	1.8
Total cost	2,288	15.6

3.1.15 Summary of H_2 storage costs for all storage technologies

The unit cost for all the storage technologies is reported in Table 31, together with the range of validity for which a simple cost interpolation is suggested, and the scaling law exponent for out-of-range estimates. The cost functions are plotted in Figure 10, in the range of capacity between 0 kgH_2 and 1,240 kgH_2. For the underground (or geological) storage, the cost for hard rock is plotted, which is \$0.52 /kWh.

Figure 11 shows the same plot between 0 kgH_2 and 15 kgH_2, neglecting the cost of metal hydride storage. For hydrogen storage with a capacity of 5.6 kgH_2, the most economical option is cryo-compression (\$15.1 /kWh), followed by liquid hydrogen (\$15.4 /kWh), complex hydride (\$15.6 /kWh), metal organic framework (\$17.9 /kWh), compressed gas (\$20.4 /kWh), and metal hydride (\$225.2 /kWh). The range for underground storage starts at 8.9 kgH_2, and therefore is not a viable option for this capacity.

Table 31 – H_2 storage cost summary

	Capital Cost ($/kWh)	Range (kgH_2)	Out of range exponent	Additional cost
Compressed gas	20.4	0.089- 1,240	-	Compressor:
Underground	0.21-0.52		-	Piping, compressor
Liquid	15.4	0.089 - 270	0.70	Liquefier: $1,241.6-5,722.8 /kWh/h
Cryo-compressed	15.1 10.6	5.6 - 10.4	0.43	-
Metal organic	17.9- 13.7	5.6 - 10.4	0.57	-
Metal hydride	2,918.9-225.2	0.036 - 0.089	0.75	-
	225.2-87.6	8.9 - 890		
Complex hydride	15.6	5.6	-	-

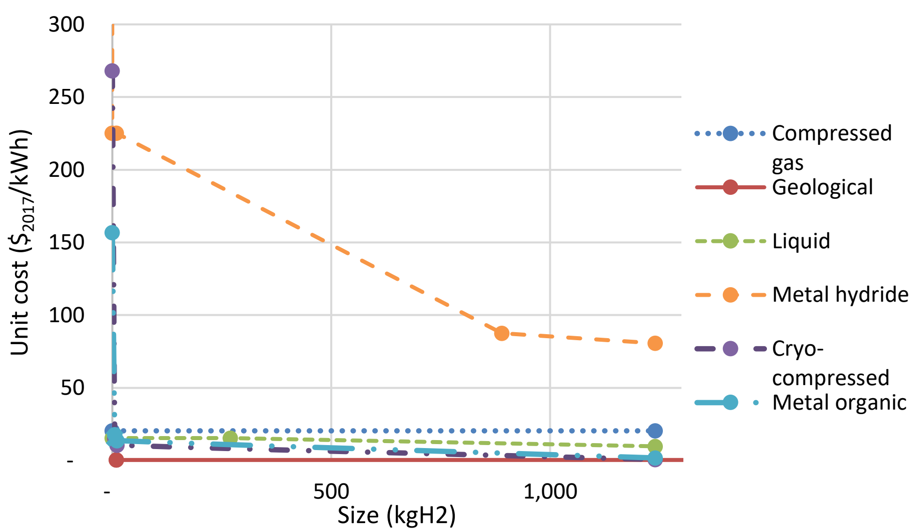

Figure 10 – Hydrogen storage cost comparison (0-1,240 kgH_2)

For storage systems of 10.4 kgH_2 of hydrogen, the cheapest technology is underground storage ($0.34 /kWh), followed by cryo-compression ($10.60 /kWh), MOF ($13.7 /kWh), liquid ($15.4 /kWh), compressed gas ($20.4 /kWh) and metal hydride ($224.9 /kWh). It is important to notice that Amos (1998) presented the cost of underground storage with capacity of 8.9 kgH_2 ($0.34 /kWh), without specifying the type of geological formation that this cost is referred to. The cost is here plotted and used as an interpolation value for underground storage.

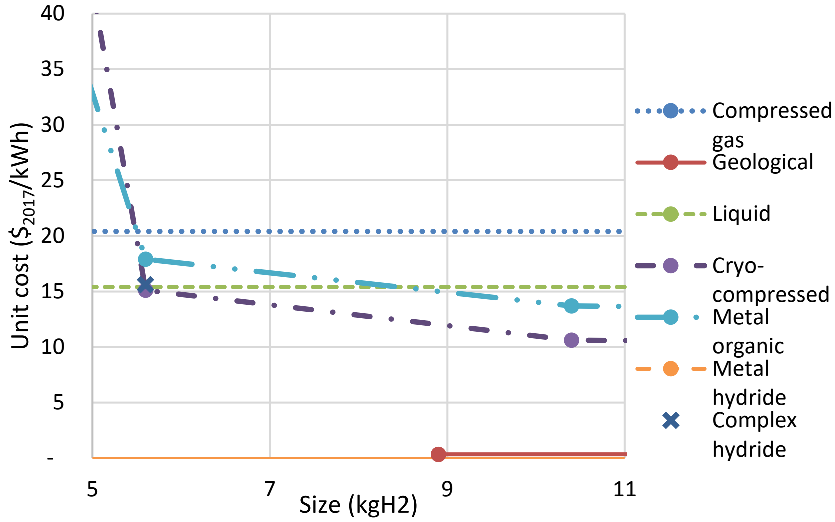

Figure 11 – Hydrogen storage cost comparison (5-11 kgH_2)

Figure 12 shows the cost of hydrogen storage systems of very small size (0-6 kgH_2). For capacities in the range 0-5.6 kgH_2, liquid storage is the most economical option ($15.4 /kWh). For sizes below 4.2 kgH_2, the next cheapest option is compressed gas ($20.0 /kWh), followed by MOF ($157.7-50.0 /kWh), cryo-compression ($269.8-78.8 /kWh) and metal hydride ($225.0 /kWh). For quantities between 0.036 kgH_2 and 1 kgH_2, metal hydride is cheaper than cryo-compression. However, at 0.036 kgH_2, a very high cost ($268.1 /kWh) was found for metal hydride.

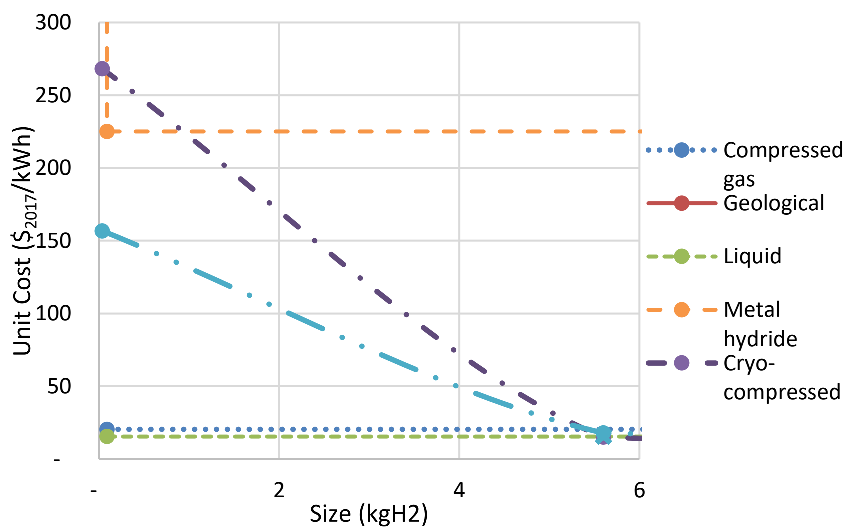

Figure 12 – Hydrogen storage cost comparison (0-6 kgH_2)

O&M costs for the different hydrogen storage technologies are summarized in Table 32. The cheapest O&M cost is found for metal hydride and for the other absorbent systems, since the metal hydride cost was assumed also for metal organic and complex hydride. The second most economical O&M cost is for compressed gas, followed by liquid, cryo-compression, and underground storage. Capital costs and O&M costs for all storage technologies are summarized in Table 33.

Table 32 – O&M cost summary for hydrogen storage

	$\$_{2017}$/kWh
Compressed gas	0.037
Underground	0.11
Liquid	0.062
Cryo-compression	0.099
Metal organic	0.02
Metal hydride	0.02
Complex hydride	0.02

Table 33 – Capital cost and O&M cost summary for hydrogen storage

	Capital Cost ($/kWh)	Range (kgH_2)	Out of range exponent	Additional cost	O&M Cost ($/kWh)
Compressed gas	20.4	0.089- 1,240	-	Compressor:	0.037
Underground	0.21-0.52		-	Piping…	
Liquid	15.4	0.089- 270	0.70	Liquefier: $1,241.6-5,722.8 /kWh/h	0.062
Cryo-compressed	15.1 10.6	5.6- 10.4	0.43	-	0.099
Metal organic	17.9- 13.7	5.6- 10.4	0.57	-	0.02
Metal hydride	2,918.9-225.2	0.036- 0.089	0.75	-	0.02
	225.2-87.6	8.9- 890			
Complex hydride	15.6	5.6	-	-	0.02

3.2 Hydrogen transportation

For the transport of hydrogen, possible options include compressed gas, liquid hydrogen, and metal hydride. Modes of transportation includes truck, rail, and barge transport and pipeline delivery. Amos (1998) conducted a literature review of hydrogen transportation, including an extensive cost analysis with all options for hydrogen transportation, considering a series of one-way transport distances (10-1,000 miles) and production rates (5-45,359 $kgH_2/2$). The assumptions of this study are summarized in Appendix A, while the results are shown in Appendix B. The transportation method to be chosen highly depends on the on the assumptions on distance, capital costs (for truck, rail, pipeline, barge), wages, fuel costs and production rates. Therefore, it is not possible to compare the cost of each transportation method through a single metric, e.g. $/$kgH_2$ or $/mile, but the optimal choice will be dependent on the particular scenario considered.

3.2.1 Hydrogen transportation as compressed gas

Tube trailers (i.e. several steel cylinders mounted to a protective framework) can be configured to transport 60-460 kgH_2 in compressed-gas form, with operating pressures of 200-600 atm (Amos, 1998). Amos (1998) reports of a quote of $340,000 for a tube trailer with a capacity of 460 kgH_2. On top of the amortization cost of the trailer, transportation cost through truck depends also on the fuel cost and driver wages.

Hydrogen is delivered by pipeline in several industrial areas of the United States, Canada, and Europe. Typical operating pressures are 100-300 atm with flows of 310-8,900 kgH_2/hr. Germany has a 210 km pipeline that has been operating since 1939, carrying 8,900 kgH_2/h of hydrogen through a 0.25 m pipeline operating at 2 MPa (290 psig). The longest hydrogen pipeline in the world is owned by Air Liquide and runs 400 km (250 miles) from Northern France to Belgium (Hart 1997). The United States has more than 720 km (447 mi) of hydrogen pipelines concentrated along the Gulf Coast and Great Lakes (Amos 1998).

Table 34 – Pipeline installation costs from Amos (1998), escalated to 2017 USD

	Length (mi)	Cost ($\$_{2017}$/mi)
	48.7	0.6 M
	67.4	2.0 M
	29.1	2.7 M
	454.0	3.2 M
	349.0	1.8 M
	25.0	0.3 M
Average		1.8 M

Hydrogen pipeline cost can be deduced from the cost of natural gas pipelines, even though H_2 pipelines generally have a diameter of 0.25-0.3 m and an operating pressure of 10-30 atm, while natural gas pipelines can be as large as 2.5 m and operate at a higher 75 atm pressure. Cost to install natural gas pipelines were found from $0.3 million/mile to $3.2 million/mile, with an average of $1.7 million/mile (Table 34).

The major operating cost for hydrogen pipelines is compressor power and maintenance. Two studies in Amos (1998) have total costs of pipeline transportation normalized per kg of H_2: one

European cost puts the cost of transportation of compressed H_2 from North Africa to central Europe (3300 km with an undersea stretch) at \$0.9-1.2 /kgH_2 (\$1.35-1.80 /kgH_2 in 2017 USD; with a middle point of \$1.575 /kgH_2), while a USA study found an expected cost of \$0.39 /kgH_2 (\$0.59 /kgH_2 in 2017 USD). The average between the costs of the two studies is 1.1 /kgH_2.

For large quantities of H_2, pipeline was consistently found to be the cheapest option, except when transportation requires ocean crossing, in which case liquefied hydrogen would be the cheapest option. For large pipelines, the major expense consists of installing the pipeline and not the cost of the pipeline itself. Therefore, Amos (1998) suggests that a cost decrease can be obtained if the expense of a pipeline is shared among different suppliers, as the pipeline can be installed for about the same cost. This is currently done along the Gulf Coast and around the Great Lakes.

Table 35 shows the average total costs estimated by Amos (1998) for the different transportation distances. The data shows that compressed gas truck transport has an average cost of \$5.37 /kgH_2, or \$0.07 /kgH_2/mile, while rail has a cost of \$3.60 /kgH_2 or \$0.09 /kgH_2/mile. The total transportation per mile costs as a function of distance for truck and rail are plotted in Figure 13. Truck transportation is cheaper than rail transportation for distances lower than 200 miles, while it becomes more expensive for distances in the range between 200 and 1,000 miles.

Table 35 – Compressed gas transportation total costs as a function of distance, calculated from Amos (1998)

Miles	Truck (\$$_{2017}$/kg$H_2$)	Rail (\$$_{2017}$/kg$H_2$)
10	3.07	3.53
20	1.39	3.53
50	1.76	3.53
100	2.53	3.53
200	4.01	3.53
500	8.49	3.53
1,000	16.37	4.01
Average	5.37	3.60

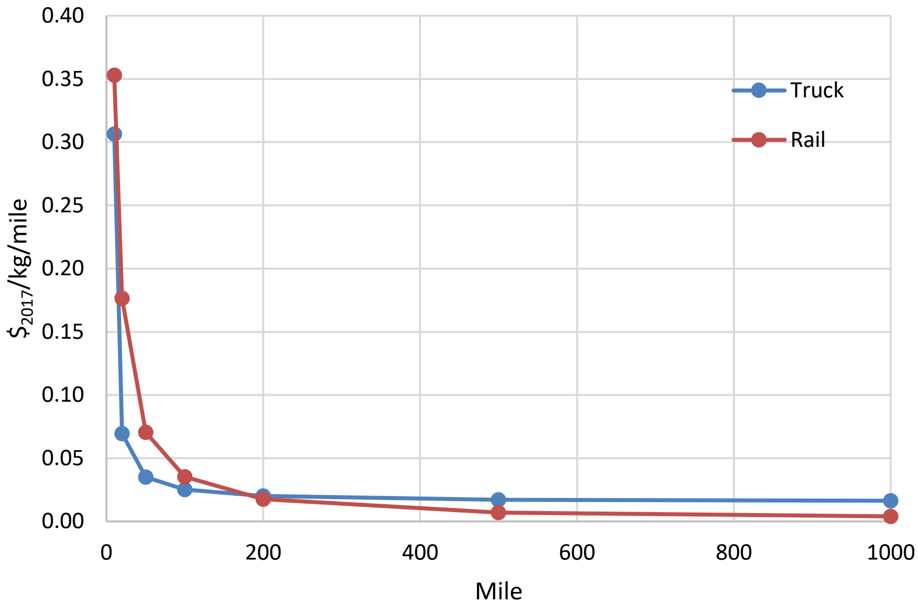

Figure 13 – Compressed gas transportation total cost per mile as a function of distance, calculated from Amos (1998)

Total cost of pipeline delivery is highly dependent on the flow rate (kgH_2/h) considered, while not strongly dependent on distance, except for high flow rates. For small flow rates and distances, the cost per unit of mass is large, as pipeline delivery is highly dependent on capital costs. On the contrary, for high flow rates the cost becomes lower, as the marginal cost is low. For this reason, Table 36 shows the total pipeline delivery cost averaged over the flow rate, instead of the distance. The whole dataset produced by Amos (1998) is reported in the Appendix B.

Table 36 – Pipeline delivery costs as a function of distance, calculated from Amos (1998)

Flow rate (kgH_2/h)	Pipeline cost ($\$_{2017}/kgH_2$)
5	320.4
45	32.0
454	3.2
4,536	0.3
45,359	0.1
Average	71.2

Table 37 – Compressed gas transportation costs as a function of distance, calculated from Amos (1998)

Miles	Transportation rate (kgH_2/h)	Pipeline cost ($\$_{2017}/kgH_2$)
10	45,359	0.0040
20	45,359	0.0025
50	45,359	0.0012
100	45,359	0.0007
200	45,359	0.0005
500	45,359	0.0003
1,000	45,359	0.0002
Average		0.0040

3.2.2 Hydrogen transportation as liquid hydrogen

Liquid hydrogen is transported using special double-walled insulated tanks to prevent boil-off. Heat shields can also be used to cool the outer wall of the liquid hydrogen vessel to further minimize heat transfer. Liquid nitrogen in insulated pipelines has been considered in connection with superconducting wires running through the pipelines. Through this method, the high cost of the insulated pipeline would be partially paid off through the superconducting transportation of electricity (Amos, 1998).

For liquid hydrogen, tank trucks can carry 360-4,300 kgH_2 of liquid hydrogen, while rail cars have even greater capacities, carrying 2,300-9,100 kgH_2 of hydrogen. Boil-off rates for trucks and railcars are typically 0.3-0.6%/day. Several designs for tanker ships similar to those for liquid natural gas have been devised (Amos, 1998; Yokogawa et al., 1996). Amos (1998) reports that cost of liquid hydrogen tanker ships would cost 3.5-4 times the cost of a liquid natural gas tanker ship. Johannsen (1993) estimated the cost for the transportation of liquid hydrogen from Africa to Europe as \$1.8-2.1 /kgH_2 (\$3.1-3.6 /kgH_2 in 2017 USD). Argonne and TIAX performed a cost analysis of transportation and refueling for the storage system for automotive applications presented in Law (2013) (ANL, 2009b). ANL (2009b) assumed a capital cost of \$330 million for 269 refueling stations, \$148 million for the LH_2 terminal, and \$35 million for 50 LH_2 tanker trucks. The terminal is the intermediate storage station between the production site and the user. The transportation cost is \$0.12/mile (\$0.14 /mile in 2017 USD), 40% of which is due to the purchased cost of the on-board storage system and 60% is due to the refueling or off-board cost.

N-ethylcarbazole is a liquid hydrogen carrier (LCH_2) investigated by Air Products (APCI), to reversibly adsorb and desorb hydrogen. The liquid carrier is hydrogenated (regenerated) at a central facility and dehydrogenated on-board in the transportation truck. The benefits of a liquid carrier over compressed, liquid, and other forms of hydrogen storage are ease of and safety during transport and storage (Law, 2013). However, the reference does not provide a transportation cost estimate.

Amos (1998) found that liquid hydrogen transport by truck is the cheapest alternative, except for large quantities of hydrogen, when pipeline delivery becomes competitive. Liquid transport by rail is almost as cheap as truck liquid transport and is cheaper than the other trucking options because of the large capacity per railcar. For small production rates, liquid hydrogen transport costs are high because the truck is not fully utilized, it may only make a few trips per week. At medium production rates (450 kg/h) and a 100 mi delivery distance, liquid hydrogen trucking is the cheapest means of transport, but metal hydride also competes because of its high storage density.

Average costs extracted from the evaluation by Amos (1998) are shown in Table 38. Transportation by truck has an average cost of \$1.07 /kgH_2 (\$0.02 /kgH_2/mile), while those by rail and barge are \$0.49 /kgH_2 (\$0.02 /kgH_2/mile) and \$3.25 /kgH_2 (\$0.08 /kgH_2/mile), respectively. The complete set of results is shown in Appendix B.

Table 38 – Liquid transportation costs as a function of distance, calculated from Amos (1998)

Miles	Truck cost ($\$_{2017}/kgH_2$)	Rail cost ($\$_{2017}/kgH_2$)	Barge cost ($\$_{2017}/kgH_2$)
10	0.90	0.49	3.15
20	0.90	0.49	3.15
50	0.92	0.49	3.15
100	0.95	0.49	3.15
200	1.02	0.49	3.15
500	1.23	0.49	3.38
1,000	1.58	0.51	3.61
Average	1.07	0.49	3.25

3.2.3 Hydrogen transportation as metal hydride

The average transportation costs from Amos (1998) are shown in Table 39. For a delivery distance of 100 miles or less, metal hydride is more expensive than both gas and liquid transportation by truck. For distances higher than 100 miles, the cost of metal hydride truck transportation falls between gas and liquid trucking. Metal hydride transportation by rail is always more expensive than gas and liquid hydrogen transportation by rail. The results of the analysis performed by Amos (1998) are reported in Appendix B.

Table 39 – Metal hydride transportation costs as a function of distance, calculated from Amos (1998)

Miles	Truck cost	Rail cost

	($\$_{2017}$/kg$H_2$)	($\$_{2017}$/kg$H_2$)
10	10.42	4.38
20	2.35	4.38
50	2.54	4.38
100	2.91	4.38
200	3.63	4.38
500	6.17	4.38
1,000	10.17	5.48
Average	5.45	4.54

3.2.4 Summary of hydrogen transportation costs

A list of the decision making criteria for H_2 transportation is summarized below (from Amos 1998):

- Pipeline: For large quantities over short and long distances
- Liquid Hydrogen: For long distances.
- Compressed Gas: For small quantities over short distances.
- Metal Hydride: For short distances.

Transportation by truck, rail and barge of gas hydrogen, liquid hydrogen, and metal hydride are summarized in Table 40. Table 41 reports the pipeline transportation costs as a function of the delivery distance. To estimate hydrogen transportation costs, it is suggested to use the values reported in the table. For values of distance not shown in the tables, it is recommended to use a simple interpolation between the values.

Table 40 – Summary of hydrogen transportation costs ($\$_{2017}$/kg$H_2$)

	Gas		Liquid			Metal hydride	
Miles	Truck	Rail	Truck	Rail	Barge	Truck	Rail
10	3.07	3.53	0.90	0.49	3.15	10.42	4.38
20	1.39	3.53	0.90	0.49	3.15	2.35	4.38
50	1.76	3.53	0.92	0.49	3.15	2.54	4.38
100	2.53	3.53	0.95	0.49	3.15	2.91	4.38
200	4.01	3.53	1.02	0.49	3.15	3.63	4.38
500	8.49	3.53	1.23	0.49	3.38	6.17	4.38
1,000	16.37	4.01	1.58	0.51	3.61	10.17	5.48
Average	5.37	3.60	1.07	0.49	3.25	5.45	4.54

Table 41 – Summary of pipeline delivery costs as a function of distance

Flow rate (kgH_2/h)	Pipeline cost ($\$_{2017}$/kg$H_2$)

5	320.4
45	32.0
454	3.2
4,536	0.3
45,359	0.1
Average	71.2

4. N-R HES capacity planning optimizations

4.1 Introduction

A study was conducted with the scope of gain familiarity with the HYBRID framework, while initiating the generation of a useful set of cases that highlight the value of hybrid energy systems. With this objective, a capacity planning optimization problem was formulated and initialized. The problem aims to determine the energy mix leading to the least cost of electricity, i.e. the different plant sizes necessary to satisfy a given demand profile.

4.2 Methodology

The capacity planning optimization evaluates the installed capacity of each component of the system, in order to find the optimal size of each component that minimizes the total system's Levelized cost of Electricity (LCOE), which is net of other revenue sources, such as the revenue deriving from the sale of hydrogen. The N-R HES analyzed in this work consists of the following components:

- Balance of plant (nuclear reactor, BOP);
- Secondary energy source (Gas turbine, SES);
- Renewable source (wind farm);
- Energy storage (ES);
- Industrial process (hydrogen production, IP).

In the first set of optimization cases presented in this Section, the following assumptions were made:

- The wind turbine has a capital cost: \$1,877/ kW (linear with capacity installed); O&M fixed cost: \$39.7 /kW-y, consistently with the values provided in Chapter 2 of this report
- The nuclear reactor has a fixed capacity of 300 MW_e;
- The gas turbine has an installed capacity between 0.001 MW_e and 600 MW_e;
- The renewable penetration is between 0% and 99.999%;
- The energy storage has an installed capacity between 0 MWh and 300 MWh;
- The industrial process has an installed capacity between 0 MW_e and 300 MW_e. The nuclear reactor is forced to produce at full thermal power all the times. The thermal energy can be either delivered to the grid or sent to the industrial process. The produced hydrogen is assumed to be sold at the fixed price of \$1.75 /kg.

The electricity demand and the wind production profile are treated stochastically. A demand profile is sampled through the ARMA module along with the wind speed profile for each hour of the day. Then, once the wind speed profile is converted to electricity, the demand, "net" of renewable production is calculated as the difference between the demand and the electricity produced through renewables. The net demand is then dispatched through the other components of the N-R HES through a least marginal cost model. A cash flow, representing the capital and operation cost of all components, is evaluated by the cash-flow module. The LCOE is then computed so that the resulting Net Present Value (NPV) of all cash flows is zero. The cash flow calculation is described in detail in Epiney et al. (2017). Positive cash flows, such as the revenue resulting from hydrogen sale, have the effect to reduce LCOE.

The optimizations were performed at fixed mean values of the demand. The ARMA is trained on a demand with a mean of about 1.1 GW. Once this demand is normalized, it is multiplied by an approximate mean demand, called “scaling demand” in Epiney et al. (2017), which is used by the dispatch module. Therefore, a demand having an approximate mean demand of 100 MWe has a mean value of about 110 MWe. Five optimizations were performed at approximate mean demand values of 100 MW, 200 MW, 300 MW, 400 MW, 500 MW, and 600 MW. For every case, a total number of 3,000 iterations were run. Since the HYBID model of the N-H HES did not included the cost of wind, the capital and O&M costs of wind turbine shown in Section 2 were added. However, the wind turbine costs are expressed in terms of the installed capacity, which is not present in the HYBID model as a variable. Therefore, the HYBRID model was modified, and the wind installed capacity was calculated from the renewable penetration.. The renewable penetration ($WIND_{fract}$) is defined as the installed capacity percentage of renewable sources over the total installed capacity of all electricity sources:

$$WIND_{fract} = \frac{P_{wind}}{P_{nuke} + P_{gas} + P_{wind}}$$

Multiplying both sides of the equation by the fraction denominator and rearranging, we obtain that the installed power of the wind farm is:

$$P_{wind} = \frac{WIND_{fract}\,(P_{nuke} + P_{gas})}{1 - WIND_{fract}}$$

The calculated installed wind capacity was included in the HYBRID framework.

4.3 Discussion of the results

4.3.1 Case with fully-costed wind

The convergence history for the case with an approximate mean demand of 600 MW_e is shown in Figure 14 and Figure 15. All variables can be considered fully converged after the 141st iteration. The results of the simulations are shown in Table 42, plotted in Figures 14-18 and discussed in Section 3.1.

Table 42 – RAVEN optimization results

Appr. mean demand (MW)	LCOE ($/MWh)	$WIND_{fract}$ (%)	SES capacity (MW)	IP capacity (MW)	ES capacity (MWh)
100	159.4	0	108	196	13
200	101.2	0	21	119	86
300	83.0	0	143	118	112
400	76.1	0	239	64	215
500	70.1	0	376	46	55
600	65.0	0	475	0	277

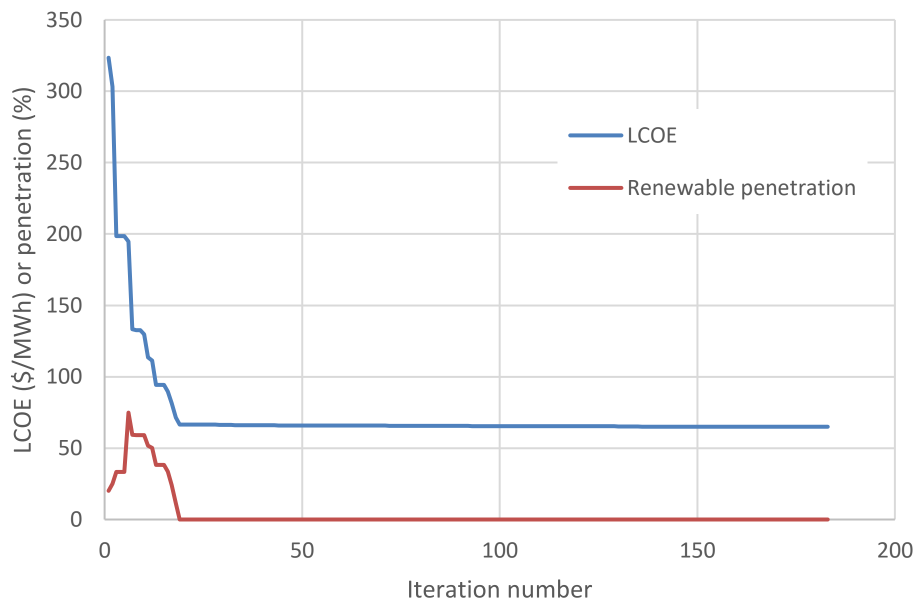

Figure 14 – LCOE and renewable penetration convergence history (600 MW approximate mean demand case)

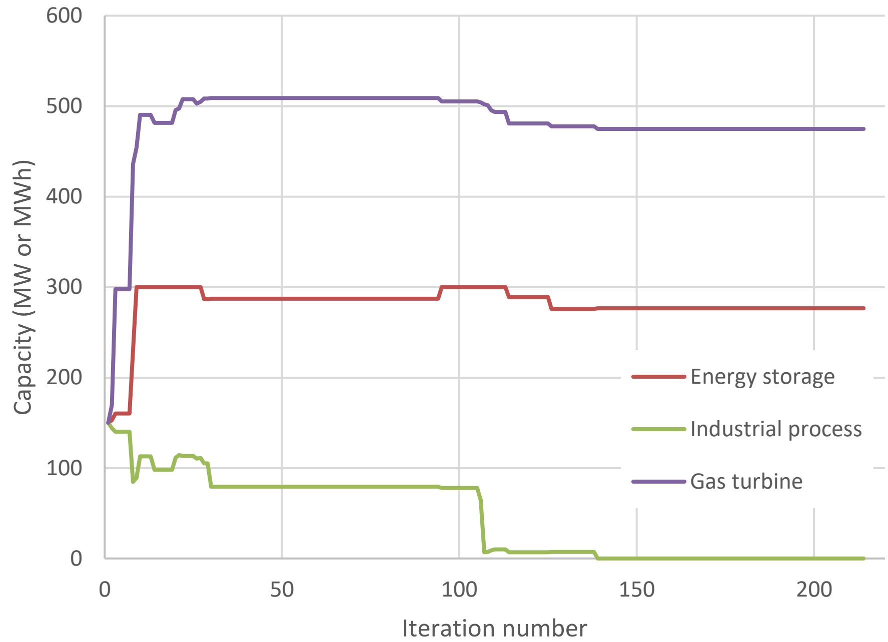

Figure 15 – Energy storage, industrial process, and gas turbine convergence history (600 MW approximate mean demand case)

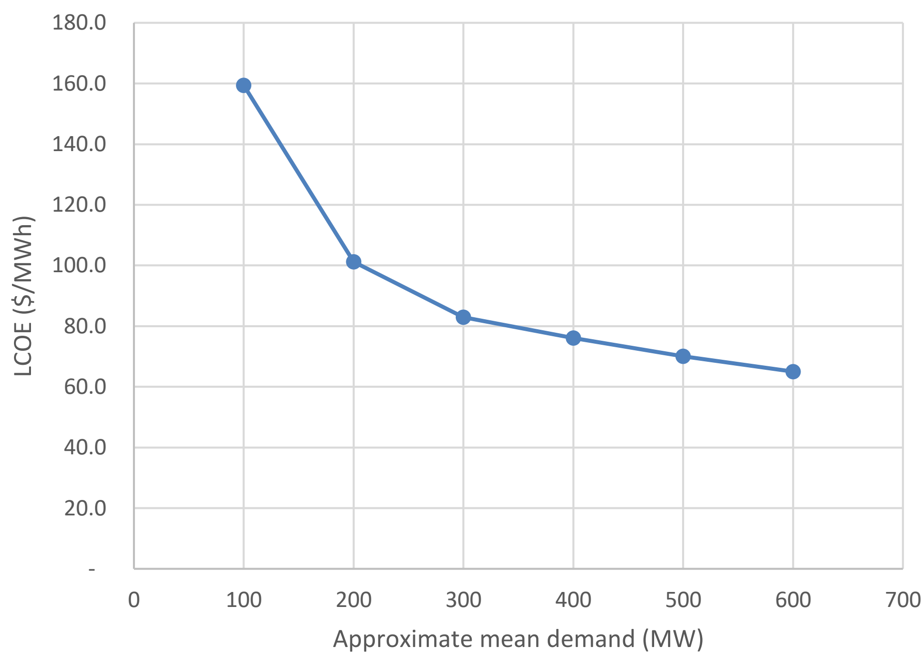

Figure 16 – LCOE as a function of the approximate mean demand

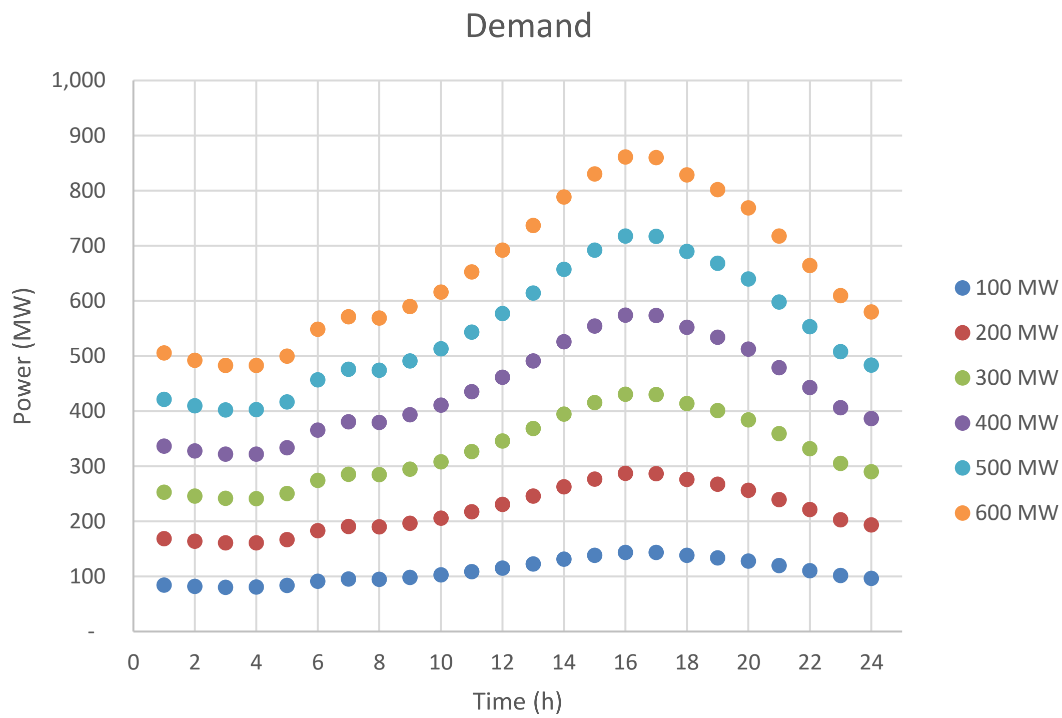

Figure 17 – Net demand as a function of time

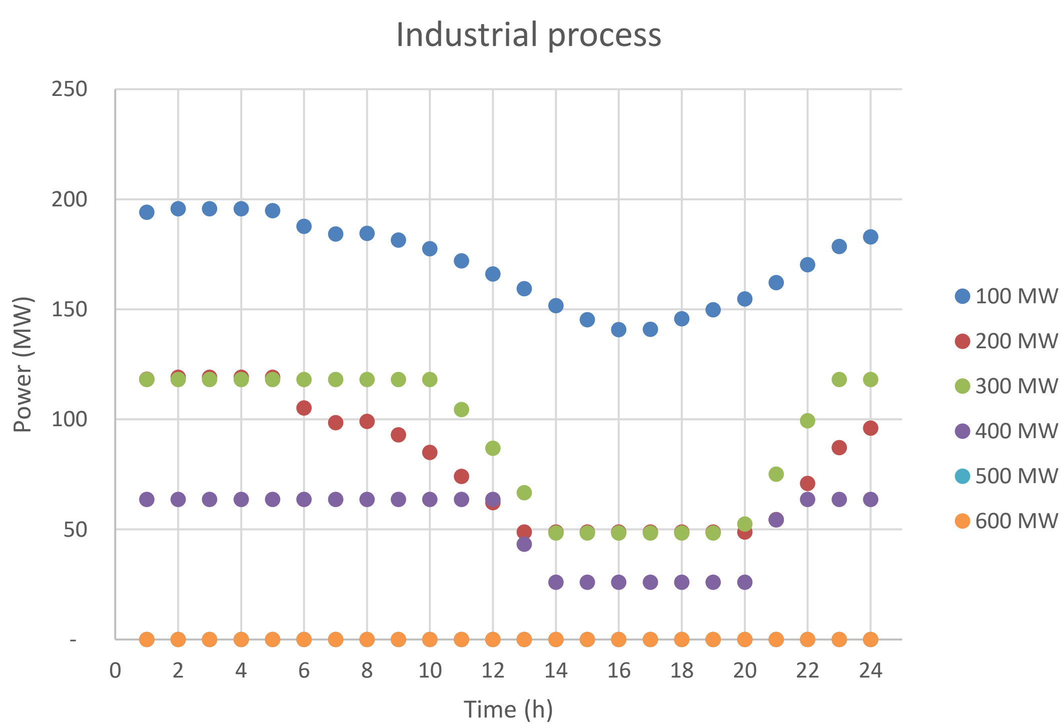

Figure 18 – IP power as a function of time

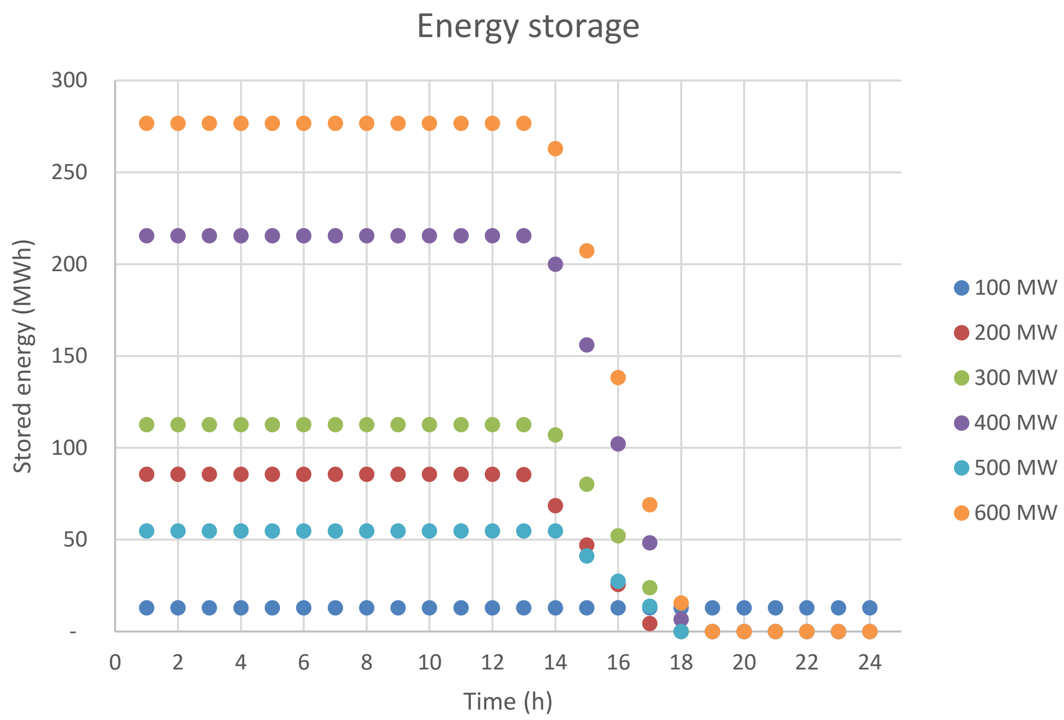

Figure 19 – ENERGY STORAGE stored energy as a function of time

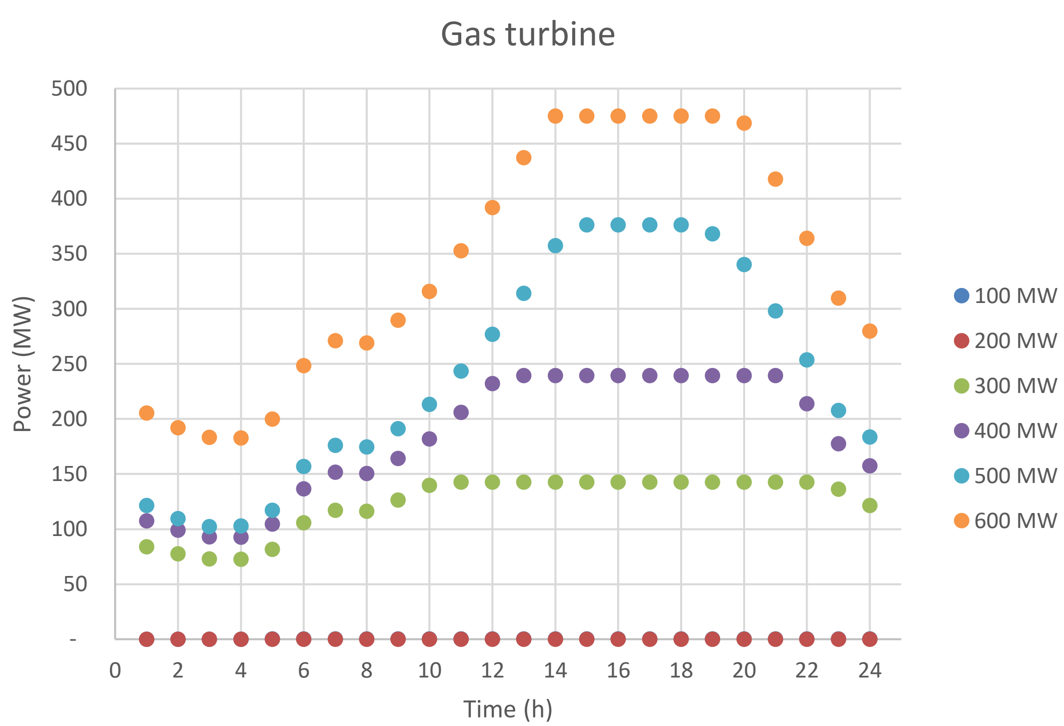

Figure 20 – GAS TURBINE dispatched power as a function of time

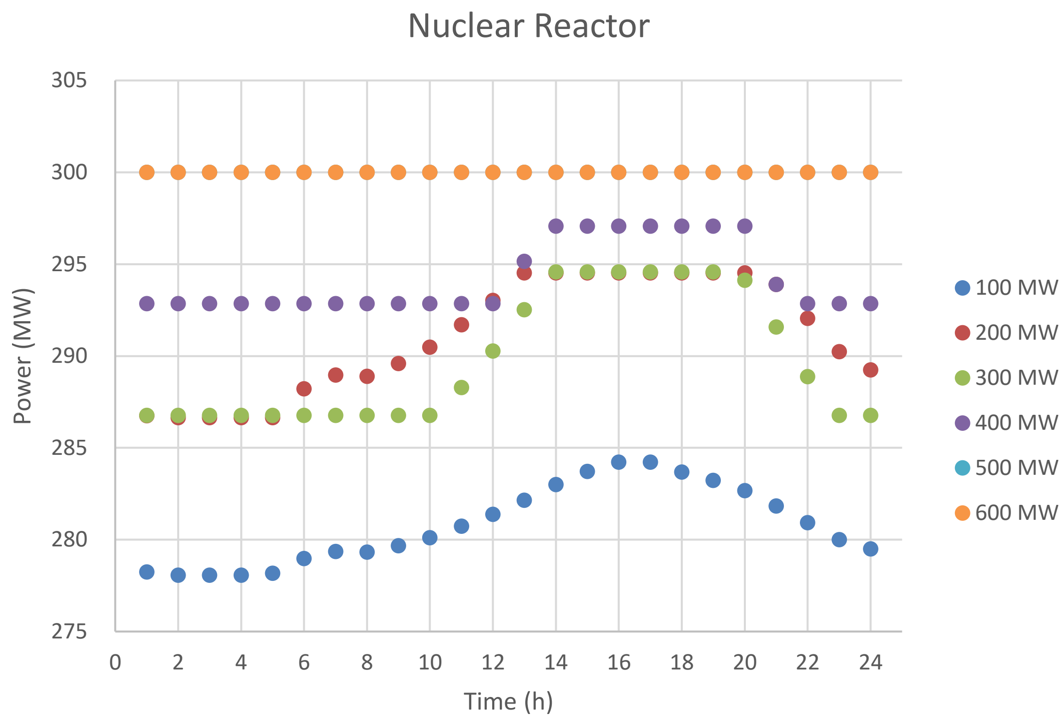

Figure 21 – NUCLEAR REACTOR dispatched power as a function of time

The following is observed:

- The size of the energy storage, as expected, increases with the difference between the demand and the available supply from the nuclear reactor (Figure 19).
- At the approximate mean demand of 100 MW, the energy storage capacity is never zero, despite the fact that the storage device is never used. It would instead be expected that, if never used, the optimal size would be zero, as it would reduce capital costs. The reason of this behavior may need to be understood in future work (Figure 19).
- For low approximate mean demand (100 MW), the IP is preferred over the energy storage (Figure 18, Figure 19), and this situation is reversed as the demand increases. For all cases, at $t=0$ the battery is assumed to be full. Afterwards, at some point during the day, the stored energy is used to cover the demand (Figure 19), while the IP is useful during other parts of the day to absorb the excess demand. , Performing the same calculations with an empty energy storage as initial condition would provide valuable understanding of the system's optimal configurations, as the initialization with full battery might affect the optimal IP size. Starting with an empty storage, it is possible that the battery would be preferred over the industrial process.
- It is observed that LCOE decreases with increasing demand (Table 42, Figure 16), while the IP capacity decreases, eventually going to zero for a large enough demand (500-600 MW, Figure 19). The reason of this behavior needs to be better understood in future work. At this point, it appears that supplying power to the IP is not competitive with delivering

electricity to the grid. This implies that the highest value of hybrid systems should be found in systems with a low demand in relation to the fixed installed capacity, as this case shows. However, future simulations should be performed to better understand this effect, and possibly different case studies may better clarify this important issue.

- For the case with approximate mean demand of 500 MW, the battery capacity is lower than the 400 MW case. Therefore, the point at 500 MW appears to be an outlier. The reason for this may be just numerical, or it would need to be understood in future work (Table 42).
- As expected, the nuclear plant dispatches exclusively electricity when the demand clearly exceeds the power of the nuclear reactor (for example in the cases with 500 MW and 600 MW of demand). When the demand it is more comparable to the size of the nuclear plant (400 MW and lower), the system starts taking advantage of the hybrid configuration (Figure 21). The breakeven points related to this optimality should be studied in future work.
- The optimal industrial process size decreases with higher demand (Figure 18). As the demand increases, the nuclear reactor needs to cover the additional demand, and therefore the optimal amount of thermal energy sent to the IP decreases (Figure 21). The relationships and breakeven points for this optimality should be studied in future work.
- The optimizer found the gas turbine to be competitive over wind turbine in all the simulations, even with the highest demand (Table 42). This is expected considering the high capital cost of wind and its relatively low capacity factor, as compared to the gas turbine. For this reason, the sensitivity to the capital and O&M cost of wind should be performed in the future to understand the optimal wind penetration, and therefore the value of wind for hybrid energy systems.
- The wind profiles were not shown in this discussion, because they were not immediately available. In the future, the wind generation profile should be superposed to the demand profile to better understand the value of the electricity produced by wind during different times of the day. In fact, the time of the day when the wind turbines produce electricity is an important factor in determining its value.
- The code optimizes the system so that the gas turbine produces at full capacity on the demand peak. As the demand increases, the peak plateau becomes narrower (Figure 20). This effect seems to be different for the case of the largest demand, when the plateau seems to be broader than the case of 500 MW. This effect should be better understood in the future, even though it is possibly related to the un-expected ES optimal size found for the 500 MW case (which is discussed in the 5th bullet above).
- With low demand, the reactor is sufficient by itself (with a little bit of energy storage and industrial process) to satisfy all the situation during the day (Figure 21). The value of hybrid systems at low values of demand needs to be studied more in future work.

4.3.2 Case with no wind capital cost

Separately, a number of cases were calculated, setting the capital cost of the wind to zero, while keeping the fixed O&M cost at its nominal value. These cases were selected to verify that the wind optimal capacity of zero, in the cases discussed in Section 4.3.1, is due primarily to the wind's high cost. By setting the wind cost to zero, an upper bound is obtained of the optimal wind penetration, in an unrealistically favorable situation for the wind production. The results are shown in Figure 22.

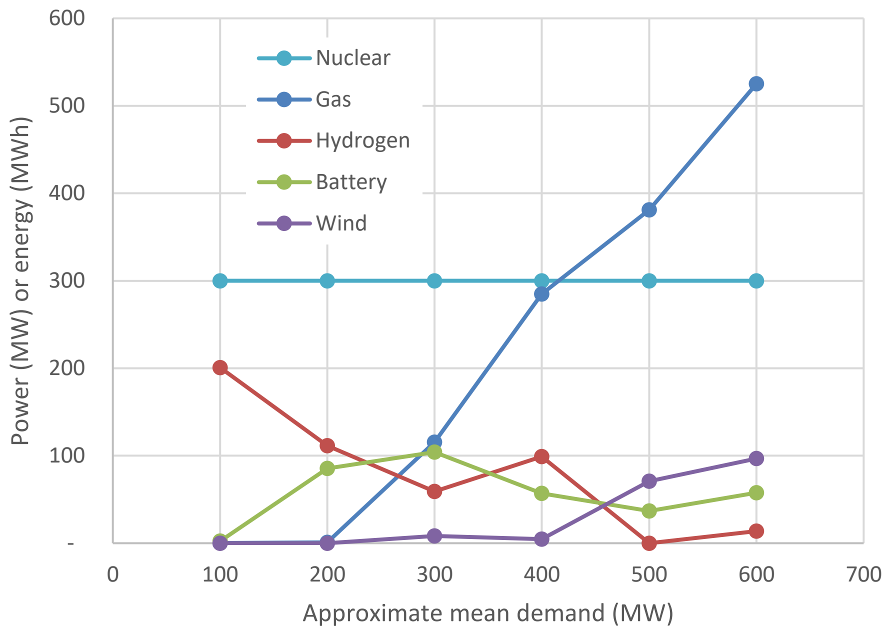

Figure 22 – Size of components as a function of the approximate mean demand (case with no wind capital cost)

The following is observed:

- As expected, the optimal wind penetration increases as the demand increases, starting only when the total demand exceeds the power of the reactor by a substantial amount (only for a demand of 500 MW and 600 MW). In any case, the optimal wind penetration never exceeds 10% or 12% in the case studied, even with a capital cost of wind of $0.
- Considering that the nuclear capacity is fixed, and therefore its capacity cannot be increased even when demand increases, the demand increase is supplied primarily by the second most economical source, which is the gas turbine. Nuclear is the most economical source for sizes of total demand of at least 200 MW_e, as is discussed in Section 4.3.3.
- The industrial process capacity decreases with increasing demand similar to the case with fully-costed wind, indicating that the maximum value of hybrid configurations is obtained for cases with low demand in relationship to the nuclear plant size.
- The optimal energy storage capacity appears somewhat independent of the total demand, with the exception of the case with the lowest demand. This behavior needs to be better studied in future work, even though it is understood that the required flexibility to satisfy

the power variations during the day, can be provided either by the gas turbine or by the energy storage, somewhat interchangeably.

4.3.3 Case with optimal nuclear size

In this case, the nuclear reactor capacity is an optimization variable, i.e. RAVEN is free to choose the optimal size of the nuclear plant for various levels of demand. For this set of simulations, the full capital cost of wind is included, in order to study a system as realistic as possible. As can be seen in Figure 23, the optimal wind capacity for this system is consistently zero. Nuclear instead, appears generally the most economical way to produce power, since it clearly generates the majority of the electricity needed in most of the cases, with the exception of the cases with the lowest demand (100 MW_e and 200 MW_e). It is noted that the 200 MW_e case presents somewhat a different trend than the other trends. It is likely numerical, but it could be investigated in future work. The industrial process size is maximum at the lowest level of demand: this shows that, likely, the highest value of the hybrid configuration is at low demand levels in relationship to the optimal size of nuclear plants: this should be studied in greater detail in future work.

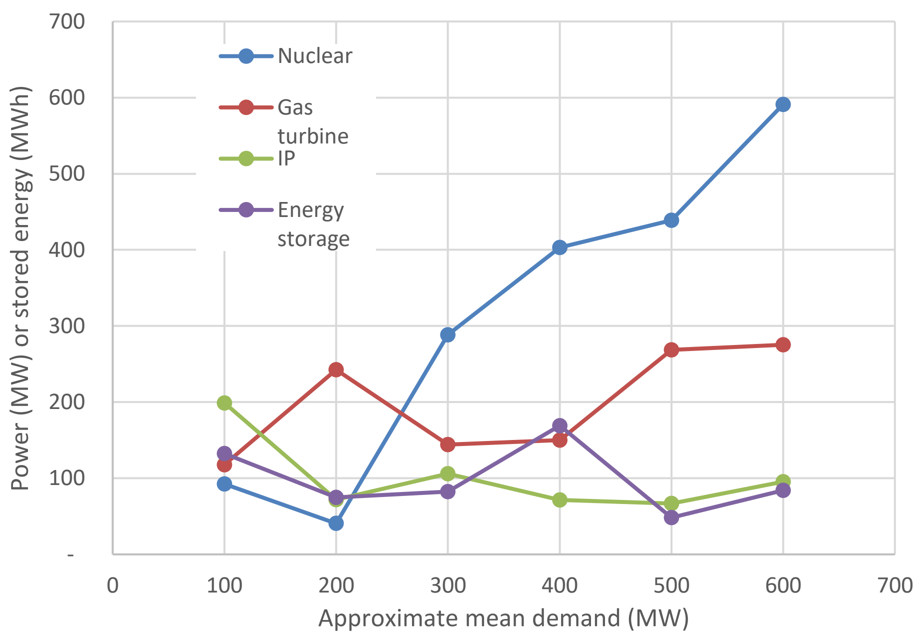

Figure 23 – Size of components as a function of the approximate mean demand (case with optimal nuclear size)

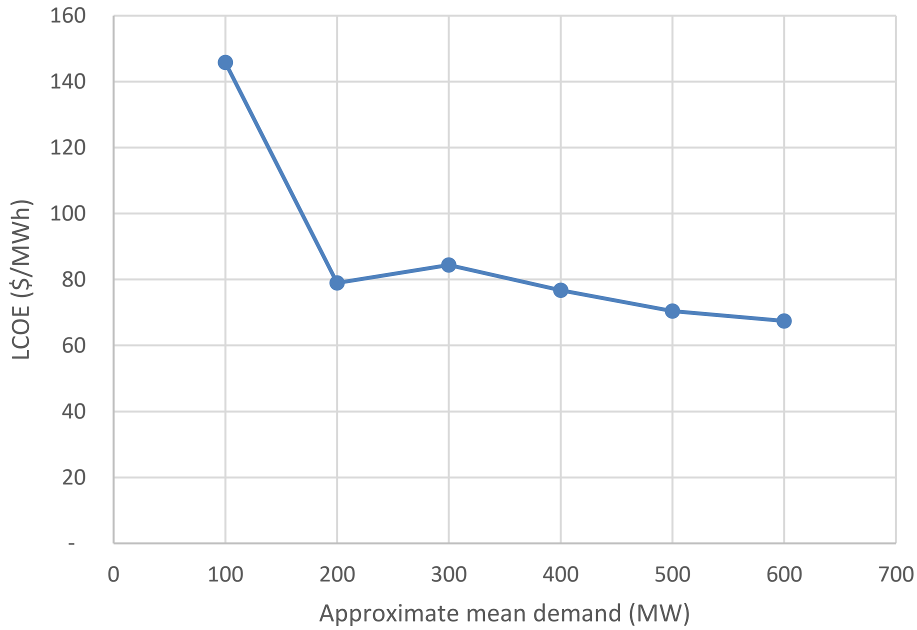

Figure 24 – LCOE as a function of the approximate mean demand (case with optimal nuclear size)

5. Conclusions

This report includes cost inputs for the simulation framework developed for the Nuclear-Renewable Hybrid Energy Systems (N-R HES) project, as well as the initial results of a study on the optimal penetration of renewables in the N-R-HES system, under various conditions.

Capital and O&M costs, as well as capacity factors and lifetime of solar photovoltaic and wind turbines, were collected from several sources and are summarized in this report.

On the costs of hydrogen storage and transportation, a review of different technologies was performed, and the cost drivers of each technology were identified. Agreements and discrepancies in the cost estimates between different sources are discussed, and summary cost ranges for each technology are provided.

Finally, RAVEN calculations were performed in order to gain familiarity with the N-R HES simulation framework, and also to initiate a study of the optimal penetration of renewables in the N-R-HES system, under various conditions. Three different capacity planning optimization studies of the N-R HES were performed, finding the optimal size of each element of the system (gas turbine, energy storage, wind turbine, industrial process) that minimize the levelized net cost of electricity for a given demand profile. The first case included the full cost of wind, according to the data provided in the relevant section of this report, for varying levels of demand. The second case zeroed-out the capital cost of wind, to observe the effect of cost on the optimal wind penetration. A third case studied the optimal system configuration, while letting the optimizer choose the optimal size of all the elements, including of the nuclear plant. This showed that the optimal size of wind at full cost is zero at all levels of demand, while nuclear appears generally the most economical way to produce power. The optimal industrial process size was found to be maximum at the lowest level of demand for the case studied. This shows that, likely, the highest value of the hybrid configuration is at low demand levels in relationship to the optimal size of the nuclear plant: this should be studied in greater detail in future work.

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Appendix A – Hydrogen storage cost data

Potentially useful sets of data (cost of equipment, unit cost of utilities, etc.) used by Amos (1998) in the cost of hydrogen transportation are provided in Table 43 and Table 44 (Amos 1998).

Table 43 – Hydrogen Transport Capital Cost Assumptions (Amos, 1998)

	Cost	Hydrogen capacity (kg)
Tube Truck Intermodal Unit	\$100,000	180
Truck Liquid Intermodal Unit	\$350,000	4,080
Metal Hydride Intermodal Unit	\$2,200/kg H_2	454
Truck Undercarriage	\$60,000	
Truck Cab	\$90,000	
Rail Tube Assembly	\$200,000	454
Rail Liquid Unit	\$400,000	9,090
Rail Hydride Unit	\$2,200 /kgH_2	910
Rail Undercarriage	\$100,000	
Ship Liquid Unit	\$350,000	4,080
Pipeline Cost	\$620,000/km	
Compressor Cost	\$1,000/kW	4,000

Table 44 – Transport Operating Cost Assumptions (Amos, 1998)

	Cost
Truck Mileage	$100,000
Average Truck Speed	$350,000
Truck Load/Unload Time	$2,200/kg H_2
Truck Availability	24 h/d
Driver Availability	12 h/d
Driver Wage (Fully Loaded)	$28.75/h
Diesel Price	$1.00/gal
Truck Boil-Off Rate	0.3%/d
Rail Average Speed	25 mph (40 km/h)
Rail Load/Unload Time	2 h/trip
Rail Car Availability	24 h/d
Rail Freight Charge	$400/wagon
Rail Boil-Off Rate	0.3%/d
Average Ship Speed	10 mph (16 km/h)
Ship Load/Unload Time	48 h/trip
Ship Tank Availability	24 h/day
Ship Freight Charge	$3,000/intermodal unit
Ship Boil-Off Rate	0.3%/d
Pipeline Roughness	4.6×10^5 m
Pipeline Diameter	0.25 m (10 in.)
Pipeline Gas Temperature	10_C (50_F)
Pipeline Delivery Pressure	20 MPa (2,900 psia)
Hydrogen Viscosity	8.62 x 10-6 kg/m s
Hydrogen Gas Constant	4,124 N m/kg K
Compressor Power (0.1 to 20 MPa [14.6 to 2,900 psia])	2.2 kWh/kg(1.0 kWh/lb)
Electricity Cost	$0.05/kWh
Operating Days	350 d/yr
Trailer Depreciation	6 years, straight-line, ADS method
Truck Cab Depreciation	4 years, straight-line, ADS method
Railcar Depreciation	15 years, straight-line, ADS method
Pipeline Depreciation	22 years, straight-line, ADS method

Appendix B – Transportation cost data

Table 45 - Hydrogen transportation costs, as calculated by Amos (1989)

		Cost ($\$_{1995}$/kg)							
		Gas			Liquid			Metal hydride	
Distance (miles)	Production rate (kg/h)	Truck	Rail	Pipeline	Truck	Rail	Barge	Truck	Rail
10	5	7.06	2.29	11.93	2.41	0.97	3.01	30.38	4.56
20	5	1.8	2.29	23.86	2.41	0.97	3.01	5.43	4.56
50	5	2.02	2.29	59.65	2.42	0.97	3.01	5.52	4.56
100	5	2.42	2.29	119.3	2.44	0.97	3.01	5.68	4.56
200	5	3.24	2.29	238.6	2.47	0.97	3.01	6.01	4.56
500	5	5.7	2.29	596.49	2.58	0.97	3.03	6.99	4.56
1000	5	11.07	2.81	1192.98	2.77	0.97	3.05	8.62	4.56
10	45	0.62	2.18	1.19	0.26	0.18	1.78	0.72	2.35
20	45	0.64	2.18	2.39	0.26	0.18	1.78	0.73	2.35
50	45	0.85	2.18	5.96	0.27	0.18	1.78	0.81	2.35
100	45	1.39	2.18	11.93	0.29	0.18	1.78	0.98	2.35
200	45	2.34	2.18	23.86	0.33	0.18	1.78	1.3	2.35
500	45	5.18	2.18	59.65	0.43	0.18	1.95	3.33	2.35
1000	45	9.91	2.39	119.3	0.62	0.18	2.11	6.01	3.09
10	454	0.6	2.14	0.12	0.05	0.12	1.64	0.35	2.2
20	454	0.62	2.14	0.24	0.05	0.12	1.64	0.36	2.2
50	454	0.85	2.14	0.6	0.06	0.12	1.64	0.5	2.2
100	454	1.33	2.14	1.19	0.07	0.12	1.64	0.77	2.2
200	454	2.27	2.14	2.39	0.13	0.12	1.64	1.3	2.2
500	454	5.11	2.14	5.97	0.27	0.12	1.82	2.91	2.2
1000	454	9.85	2.39	11.93	0.5	0.14	1.99	5.59	3.09
10	4536	0.59	2.14	0.01	0.03	0.12	1.64	0.35	2.2
20	4536	0.61	2.14	0.03	0.03	0.12	1.64	0.36	2.2
50	4536	0.85	2.14	0.07	0.04	0.12	1.64	0.5	2.2
100	4536	1.33	2.14	0.13	0.07	0.12	1.64	0.77	2.2
200	4536	2.27	2.14	0.26	0.12	0.12	1.64	1.3	2.2
500	4536	5.11	2.14	0.63	0.26	0.12	1.82	2.91	2.2
1000	4536	9.85	2.39	1.23	0.49	0.14	1.99	5.59	3.09
10	45359	0.59	2.14	0.04	0.03	0.12	1.64	0.35	2.2
20	45359	0.61	2.14	0.05	0.03	0.12	1.64	0.36	2.2
50	45359	0.85	2.14	0.06	0.04	0.12	1.64	0.5	2.2
100	45359	1.33	2.14	0.07	0.07	0.12	1.64	0.77	2.2
200	45359	2.27	2.14	0.09	0.11	0.12	1.64	1.3	2.2
500	45359	5.11	2.14	0.14	0.25	0.12	1.81	2.91	2.2
1000	45359	9.85	2.39	0.21	0.49	0.14	1.99	5.59	3.09

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