CTCN Technical Assistance

"Developing a power to gas masterplan in Lao PDR"

COST-BENEFIT ANALYSIS

March 2022

Global Environment Centre Foundation

ACKNOWLEDGEMENT

This report was prepared with support from Yoshiaki Shibata, Akiko Sasakawa, and Takahiro Nagata (The Institute of Energy Economics, Japan), Phanhpakit Onphanhdala (Lao National Institute for Economic Research), Kazuya Kameyama and Minoru Hayasaki (Hitachi Zosen Corporation), and Masaaki Tabo (Chuo Fukken Coonsultants).

LIST OF ABBREVIATIONS

BAU	business as usual
BEV	battery-powered electric vehicle
CAPEX	capital expenditure
CBA	cost-benefit analysis
CNGV	compressed natural gas vehicle
FCEV	fuel cell electric vehicle
ICEV	internal combustion engine vehicle
METI	Ministry of Trade, Industry and Economy (Japan)
NPV	net present value
P2G	power-to-gas

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1. Introduction

Cost benefit analysis (CBA) will draft scenarios up to 2030 depicting the selection of P2G technologies in specific sectors of the country and for each scenario will associate an elaborated budget and correspondent CO2eq emissions savings potential through the adoption of P2G solutions in comparison with the BAU scenario. The objective of the CBA is to help assessing which policies regulation and standards in Lao are to be introduced so to best operationalize P2G technologies in consultation with relevant local partners. As such the CBA should be based on country specific requirements and circumstances.

The objectives of the CBA that will lead the scenarios drafting are: 1. Phase out of fossil fuels utilization during dry season and ideally make Lao a net zero carbon emission country by 2050 and 2. Reduction of GHG emissions.

2. Scenarios

2.1. BAU

In BAU, it is assumed that no P2G technology is implemented (do-nothing scenario). Chapter 3 figures out expected volume of surplus electricity from hydropower through 2030. The surplus electricity will occur when domestic power generation exceeds the total of domestic electricity demand and export. If no measures taken, the surplus electricity would be curtailed, which means loss of power generation opportunity that causes unrecoverable investment to hydropower.

2.2. P2G scenarios

P2G is able to provide opportunity for surplus electricity that would otherwise be curtailed. The opportunities are to produce from surplus electricity green hydrogen that can be used for mobility and industrial sector. The green hydrogen can reduce fossil fuel demand in these sectors, contributing to CO_2 emission reduction. There are majorly two paths for green hydrogen application, one of which is direct use of green hydrogen and the other is producing green synthetic methane by combining green hydrogen with CO_2 captured. This study includes five scenarios below; three are for mobility and two are industry.

1-1) Green hydrogen to mobility scenario (GH_m)

This scenario supplies green hydrogen from surplus electricity to fuel cell electric vehicle (FCEV).

1-2) Green synthetic methane to mobility scenario (GM_m)

This scenario produces green synthetic methane from green hydrogen and supplies to compressed natural gas vehicle (CNGV).

1-3) Green electricity to BEV scenario (GE_m)

There is another way to use surplus electricity other than producing green hydrogen or synthetic methane. Surplus electricity can be directly supplied to battery electric vehicle (BEV).

2-1) Green hydrogen to industry scenario (GH_in)

This scenario supplies green hydrogen from surplus electricity to industrial sector.

2-2) Green synthetic methane to industry scenario (GM_in)

This scenario produces green synthetic methane from green hydrogen and supplies to industrial sector.

3. Concept and Boundary for CBA

When analyzing P2G, power generation sector that provides surplus green electricity and the sectors that use green hydrogen/synthetic methane produced from surplus green electricity are in general comprehensively included in the boundary. However, it should be noted that there are sub-boundaries that are common among BAU and scenarios, and these common boundaries can be excluded for the sake of simplicity in CBA. For example, power generation sector can be regarded to be constant (identical) among BAU and scenarios, as the investment cost for hydropower is already incurred once hydropower is constructed no matter whether surplus electricity is curtailed or used for P2G. The differences among BAU and scenarios therefore are observed in fossil fuel consumption and additional infrastructure configuration in the mobility/industrial sector.

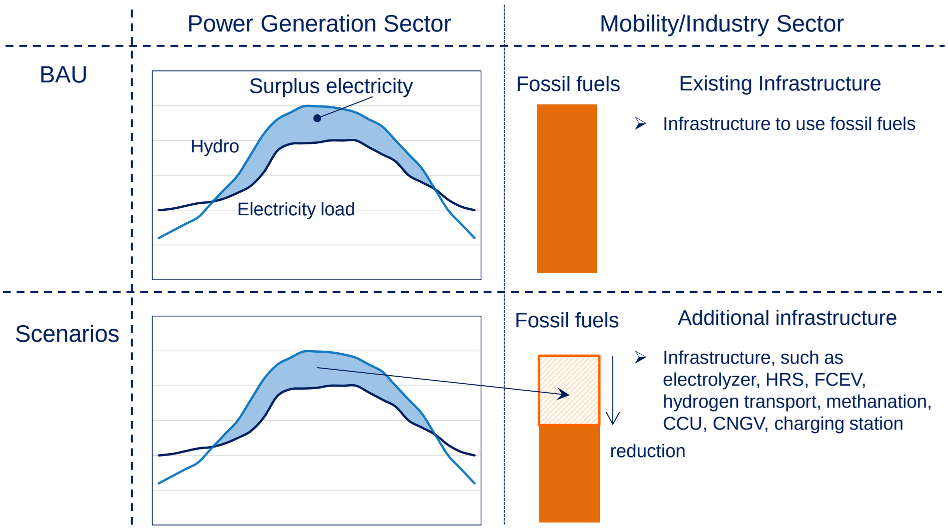


Fig 3-1 Snapshot Comparing BAU and Scenarios

Table 3-1 Infrastructure Configuration in each Scenarios

	Scenario	Production	Supply	Application
Mobility	BAU	-	Petroleum product supply chain, gas station	ICEV
	GH_m	Electrolyzer	H_2 storage & transport, HRS	FCEV
	GM_m	Electrolyzer, CO2 capture, methanation	CH_4 storage & transport, CNG station	CNGV
	GE_m	-	Charging station	BEV
Industry	BAU	-	Oil supply chain	Oil utilization equipment
	GH_in	Electrolyzer	H_2 storage & transport	H_2 utilization equipment
	GM_in	Electrolyzer, CO2 capture, methanation	Oil supply chain	Oil utilization equipment

Required infrastructure configuration in the individual scenario are shown in Table X. In the CBA, the differences in the total CAPEX between BAU and each scenario will be included in the cost, and cost reduction in fossil fuel consumption is categorized in benefit. The Economic Net Present Value (NPV), which is calculated using the interest rate for the 10-year national government bonds as discount rate, is the CBA output index per each scenario.

4. Assumptions

This section describes assumptions for CAPEX and performance of technology elements in each scenario. CBA covers till 2030 with starting date in 2021.

4.1. Basic data

Table 4-1 and Table 4-2 show HHV (Higher Heating Value) and CO_2 emission coefficient of major fuels.

Table 4-1 Higher Heating Value

Gasoline	34.6	MJ/L
Diesel	37.7	MJ/L
LPG	50.2	MJ/kg
Hydrogen	143.2	MJ/kg-H_2
Methane	55.5	MJ/kg-CH_4

Table 4-2 CO_2 Emission Coefficient

Gasoline	0.0671	kgCO_2/MJ	2.32	kgCO_2/L
Diesel	0.0686	kgCO_2/MJ	2.59	kgCO_2/L
LPG	0.0590	kgCO_2/MJ	2.96	kgCO_2/kg

The import prices of gasoline and diesel that are to be substituted by hydrogen and synthetic methane are assumed to be USD1/L, respectively[1], and the discount rate is assumed to be 5%.[2]

4.2. Technical and economic specifications

(1) Applications

As for mobility application, green hydrogen is supplied to FCEVs through HRSs (Hydrogen Refueling Stations) in GH_m scenario, green synthetic methane is supplied to CNGVs through CNG stations in GM_m scenario, green electricity is supplied to BEVs through charging stations in GE_m scenario and gasoline/diesel is supplied to ICEVs (Internal Combustion Engine Vehicles) through gasoline stations in BAU scenario.

Table 4-3 and Table 4-4 show fuel consumption of vehicles and vehicle prices and CAPEX for stations, respectively. These assumptions are set to be constant through 2030. For vehicle prices,

1 Since there is no data on the import price of gasoline for Lao PDR, 1 USD/L is selected for the illustration purpose.
2 Nomura Research Institute. Lao PDR Public Debt Analysis. https://www.nri.com/-/media/Corporate/jp/Files/PDF/knowledge/publication/chitekishisan/2020/05/cs20200507.pdf?la=ja-JP&hash=F6FF07D70DF2EB41B34646AA259AD56CE4D44FEC

the cost of BEV, FCEV, CNGV, ICEV are set at 40,000 USD, 70,000 USD, 25,000 USD, and 20,000 USD respectively. For the CAPEX of basic infrastructures, BEV charging stations is 50,000 USD, FCEV refueling station is 2,000,000 USD, CNG station is 500,000 USD, and gasoline station is 500,000 USD.

Table 4-3 Fuel Consumption of Vehicles

BEV	10.0	km/kWh
	2.8	km/MJ
	1,000	kWh/vehicle/year
FCEV	150	km/kg-H2
	1.0	km/MJ
	67	kg-H2/vehicle/year
CNGV	32	km/kg-CH4
	0.6	km/MJ
	313	kg-CH4/vehicle/year
ICEV	18	km/L-gasoline
	0.5	km/MJ
	556	L-gasoline/vehicle/year

Note: Annual driving range is assumed to be 10,000 km.

Table 4-4 Vehicle Prices and CAPEX for Stations

BEV	40,000	USD
FCEV	70,000	USD
CNGV	25,000	USD
ICEV	20,000	USD
Charging Station for BEV	50,000	USD
Hydrogen Refueling Station for FCEV	2,000,000	USD
Compressed Natural Gas Station for CNGV	500,000	USD
Gasoline Station for ICEV	500,000	USD

For the industrial application, the CAPEX of hydrogen/methane-consuming equipment are assumed to be same as that of oil-consuming. Therefore, CAPEX of these equipment are not explicitly taken into account in the CBA.

(2) Conversion, storage and delivery

Table 4-5 shows technical performance and CAPEX for conversion and storage. It should be noted that stationary battery is required to be installed in GE_m scenario (surplus electricity to BEVs). This is described in detail in 4.4. CAPEX of stationary battery cell is assumed to be reduced from USD500/kWh to USD200/kWh in 2030.

CAPEX of electrolyzer and methanation and unit electricity consumption to produce hydrogen and synthetic methane are expected to be reduced through 2030. CAPEX of storage tank for compressed hydrogen and compressed methane and CAPEX of carbon capture are assumed to be constant through 2030 (Source: Hitz report and METI).

Table 4-6 shows technical performance and CAPEX for delivery of hydrogen and methane. Number of delivery per month is assumed to be 10 times (120 times per year) and the average delivery distance is assumed to be 50 km (100 km of roundtrip).

Table 4-5 Technical Performance and CAPEX for Conversion and Storage

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Stationary battery												
Charging efficiency		90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
CAPEX of cell	USD/kWh	500	470	440	410	380	350	320	290	260	230	200
CAPEX of PCS	USD/kW	400	400	400	400	400	400	400	400	400	400	400
Electrolyzer												
unit ele consumption	kWh/Nm3-H2	4.7	4.66	4.62	4.58	4.54	4.5	4.46	4.42	4.38	4.34	4.3
unit ele consumption	kWh/kg-H2	52.6	52.2	51.7	51.3	50.8	50.4	50.0	49.5	49.1	48.6	48.2
BOP	kWh/Nm3	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4

BOP	kWh/kg-H2	5.3	5.2	5.2	5.1	5.1	5.0	5.0	5.0	4.9	4.9	4.8
CAPEX	USD/Nm3/h	2,396	2,306	2,217	2,127	2,038	1,948	1,858	1,769	1,679	1,590	1,500
CAPEX	USD/kg-H2/h	26,833	25,830	24,827	23,823	22,820	21,817	20,813	19,810	18,807	17,803	16,800
CAPEX	USD/kW	510	495	480	464	449	433	417	400	383	366	349
Compressed H2 Storage												
unit ele consumption	kWh/kg-H2	2.51	2.51	2.51	2.51	2.51	2.51	2.51	2.51	2.51	2.51	2.51
CAPEX of tank	USD/kg-H2	250	250	250	250	250	250	250	250	250	250	250
CAPEX of compressor	USD/kW	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Methanation												
unit of electrolyzer		4	4	4	4	4	4	4	4	4	4	4
unit ele consumption	kWh/Nm3-CH4	20.68	20.50	20.33	20.15	19.98	19.80	19.62	19.45	19.27	19.10	18.92
unit ele consumption	kWh/kg-CH4	28.8	28.6	28.4	28.1	27.9	27.6	27.4	27.1	26.9	26.6	26.4
BOP	kWh/Nm3-CH4	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32
BOP	kWh/kg-CH4	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
CAPEX	USD/Nm3-CH4/h	3,125	3,013	2,900	2,788	2,675	2,563	2,450	2,338	2,225	2,113	2,000
CAPEX	USD/kg-CH4/h	4,358	4,202	4,045	3,888	3,731	3,574	3,417	3,260	3,103	2,946	2,789
CAPEX	USD/kW	151	147	143	138	134	129	125	120	115	111	106
Compressed CH4 Storage												
unit ele consumption	kWh/kg-CH4	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
CAPEX of tank	USD/kg-CH4	250	250	250	250	250	250	250	250	250	250	250
CAPEX of compressor	USD/kW	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Carbon capture												
CAPEX	USD/kg-CO2/h	1,341	1,341	1,341	1,341	1,341	1,341	1,341	1,341	1,341	1,341	1,341

Table 4-6 Technical Performance and CAPEX for Delivery

		Loading Capacity	Fuel Consumption (km/L)	CAPEX (USD/vehicle)
Compressed H2	Bottle (cadre)	27 kg-H2/cadre	10	50,000
	Trailer	270 kg-H2/trailer	5	200,000
Compressed CH4	Bottle (cadre)	217 kg-CH4/trailer	10	50,000
	Trailer	2,168 kg-CH4/trailer	5	200,000
Gasoline	Tank lorry	20,000 L-gasoline	5	200,000

4.3. Number of stations and vehicles

Required number of stations should be figured out based on numbers of vehicles. The number of required stations per vehicle is presumably a function of cruising range of vehicle (cruising range is identified by fuel consumption and vehicle storage tank capacity). As the cruising range is longer, the number of required stations per vehicle is decreasing. Fig 4-1 shows number of gasoline stations per 1,000 gasoline vehicles as a function of average cruising range of gasoline vehicles. According to the function expressing the number of station and cruising range of vehicle, the required number of stations for BEVs, FCEVs, CNGVs and ICEVs are assumed in Table 4-7.

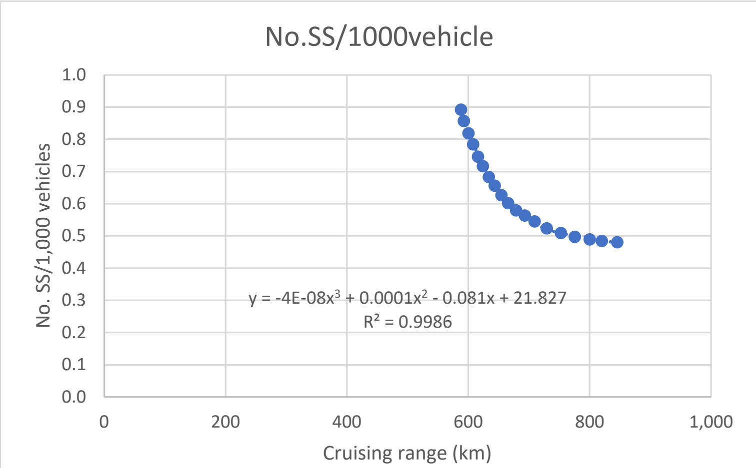


Fig 4-1 Number of Service Stations as a Function of Cruising Range in Japan

Note: Number of service station and number of gasoline vehicle come from METI, Japan and IEEJ, respectively. Cruising range is estimated from IEEJ's statistics.

Table 4-7 Required Number of Stations

	Cruising range (km)	Number of stations/1000 vehicles
BEV	400	2.9
FCEV	750	0.5
CNGV	500	1.3
ICEV	600	0.6

4.4. Storage capacity required

In general, BEVs are regarded and expected to consume grid electricity no matter how deeply decarbonized the power generation. On the other hand, hydrogen and synthetic methane are produced from surplus hydro and FCEVs and CNGVs consume 100% green gases. If this electricity consuming configuration of BEVs are allowed, CO_2 is emitted from BEVs, while no CO_2 emitted from FCEVs and CNGVs. Therefore, it should be assumed that BEVs also consume 100% green electricity from hydro surplus in order to carry out level playing field comparison in CBA.

As hydrogen/synthetic methane production profile fully dependent on surplus hydro power generation and profile of consumption of these gases by vehicles are different, storage tank should be installed to offset the difference. In the BEV scenario (GE_m), stationary battery storage is required to offset the surplus hydro power generation profile and profile of consumption of electricity by BEVs. In order to identify the required storage capacity (hydrogen tank for FCEVs, methane tank for CNGVs and stationary battery for BEVs), simple hourly simulations are carried (Fig 4-2) using hourly refueling pattern (Fig 4-3).

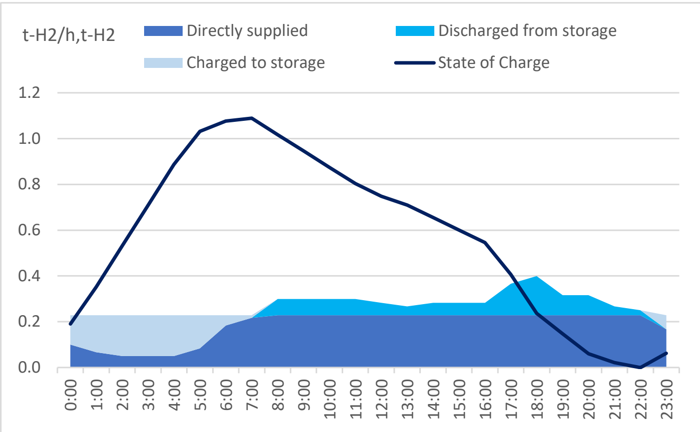


Fig 4-2 Sample of Simple Hourly Simulation to Identify Required Storage Capacity

Note: Case for hydrogen

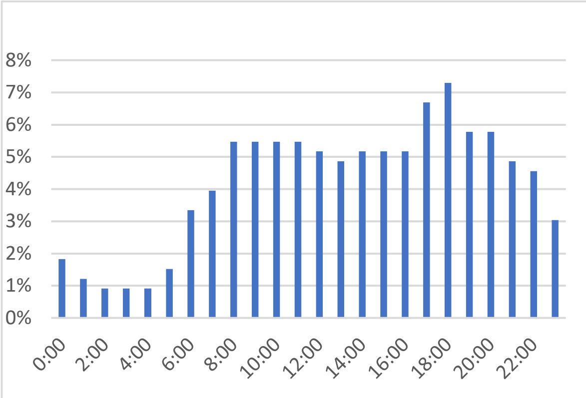


Fig 4-3 Assumption of Refueling Pattern at Station

Source: Institute of Applied Energy (IAE). Analysis on hydrogen supply price scenario.

5. Outlook of Deployment

5.1. Scale of infrastructure

Based on the Lao government target, the sales share of BEVs in 2030 will be 30%, which can be interpreted that BEVs will account for 1% of the total owned vehicles in 2030. According to the transport sector analysis contained in this report, the number of BEVs owned will be 6,300 in 2030. These BEVs are able to purchase electricity whenever needed, which means these BEVs are not necessarily carbon-neutral depending on the power generation mix including fossil fuel-fired power generation, while FCEVs and CNGVs are carbon-neutral as these vehicles purchases carbon-neutral gases from the surplus hydro power. In order to carry out level playing field comparison among BEVs, FCEVs and CNGVs, it should be assumed that additional vehicles that can be regarded as carbon-neutral are to be deployed. In this study, the number of additional carbon-neutral vehicles is assumed to be 6,300 in 2030.

Table 5-1 shows deployment scale of vehicles based on the above assumption. According to the relation between number of service stations and number of vehicles identified in 4.3, the required number of stations is estimated. The scale of conversion and storage facilities identified by the simple simulation in 4.4 is also shown in Table 5-1. For comparison, for the mobility sector, by 2030 the number of charging stations required to adequately serve 6,300 BEVs will be 18.1, whereas it is 2.8 for FCEVs, 8.4 for CNGVs, and 3.7 units for ICEVs. For FCEVs and CNGVs that use carbon-neutral hydrogen and methane, additional infrastructure such as electrolyzer, methanation facility, storage, and transport, as listed on the Table 5-1.

Similarly, Table 5-2 shows deployment scale of the scenarios for industry, which includes projected production capacity for both carbon-neutral hydrogen and methane, as well as necessary infrastructure such as storage and transport.

Table 5-1 Scale of Infrastructure (Mobility)

			BEV	FCEV	CNGV	ICEV
Vehicle	Number of vehicles	Annual (2021-2030)	630	630	630	630
		at 2030	6,300	6,300	6,300	6,300
Station	Number of stations	Annual (2021-2030)	1.8	0.3	0.8	0.4
		at 2030	18.1	2.8	8.4	3.7
Battery	Storage capacity (MWh)	Annual (2021-2030)	0.6	-	-	-
	PCS capacity (MW)	Annual (2021-2030)	0.1	-	-	-
	Storage capacity (MWh)	at 2030	6.0	-	-	-
	PCS capacity (MW)	at 2030	0.9	-	-	-
Electrolyzer	Production capacity (t-H_2/h)	Annual (2021-2030)	-	0.01	0.02	-
	Production capacity (t-H_2/h)	at 2030	-	0.07	0.16	-
	Designed power input (MW)	at 2030	-	3.8	8.8	-
Methanation	Production capacity (t-CH_4/h)	Annual (2021-2030)	-	-	0.03	-
		at 2030	-	-	0.3	-
CO_2 capture	Capture capacity (t-CO_2/h)	Annual (2021-2030)	-	-	0.09	-
		at 2030	-	-	0.9	-
Hydrogen storage	Storage capacity (t-H_2)	Annual (2021-2030)	-	0.03	-	-
		at 2030	-	0.3	-	-
Methane storage	Storage capacity (t-CH_4)	Annual (2021-2030)	-	-	0.15	-
		at 2030	-	-	1.5	-
Fuel transport	Number of trailers/lorries	Annual (2021-2030)	-	1.3	0.8	0.1
		at 2030	-	13	8	1.5
	Number of cadres	Annual (2021-2030)	-	13	8	-
		at 2030	-	130	76	-

Table 5-2 Scale of Infrastructure (Industry)

			Hydrogen	Synthetic Methane	Diesel
Electrolyzer	Production capacity (t-H_2/h)	Annual (2021-2030)	0.003	0.003	-
	Production capacity (t-H_2/h)	at 2030	0.03	0.03	-
	Designed power input (MW)	at 2030	1.5	1.9	-

Methanation	Production capacity (t-CH_4/h)	Annual (2021-2030)	-	0.007	-
		at 2030	-	0.070	-
CO_2 capture	Capture capacity (t-CO_2/h)	Annual (2021-2030)	-	0.019	-
		at 2030	-	0.192	-
Hydrogen storage	Storage capacity (t-H_2)	Annual (2021-2030)	0.013	-	-
		at 2030	0.129	-	-
Methane storage	Storage capacity (t-CH_4)	Annual (2021-2030)	-	0.033	-
		at 2030	-	0.333	-
Fuel transport	Number of trailers/lorries	Annual (2021-2030)	0.51	0.16	0.03
		at 2030	5.12	1.64	0.26
	Number of cadres	Annual (2021-2030)	5.1	1.6	-
		at 2030	51.2	16.4	-

5.2. Scale of energy and CO_2 reduction

Fig 5-1 shows required surplus electricity for mobility and Fig 5-2 shows supplied energy (electricity, hydrogen, synthetic methane and gasoline to be substituted). For Fig 5-1, it shows that in 2021, BEV, FCEV, and CNGV will require approximately 1 GWh, 2 GWh, and 6 GWh of electricity for fuel, respectively. In 2030, this number will increase to 7 GWh, 23 GWh, and 56 GWh respectively in order to serve the supposed number of each vehicles type (6,300 each). For Fig 5-2, the supplied energy for BEVs in 2021 will be 1 GWh whereas in 2030 it will accumulate to 6 GWh. For FCEVs, it will be 42 tons of hydrogen in 2021, and 420 tons in 2030. For CNGVs, it will be 197 tons of methane in 2021 and 1,969 tons of methane in 2030. The amount of substituted gasoline in 2021 is 350 kL which accumulates to 3,500 kL in 2030. Diesel required for delivery of H_2, CH_4 and gasoline for mobility is shown in Fig 5-3, which shows that FCEVs will require most diesel, which is 3 kL in 2021 and 31 kL in 2030, whereas CNGVs will require 2 kL in 2021 and 18 kL in 2030.

Fig 5-4 shows abated CO_2 emissions in mobility. As CO_2 emission from delivery of energy is much smaller than abated CO_2 emissions by substituing gasoline, the net abated CO_2 emission in each scenario (BEV, FCEV, CNGV) are almost same, which is approximately 813 t-CO2/year in 2021 and 8,120 t-CO2 in 2030.

Similar results are observed in the scenario for industry (Fig 5-5, Fig 5-6, Fig 5-7, Fig 5-8). For Fig. 5-5, required electricity, it is approximately 1 GWh for both hydrogen and methane production in 2021, and 9 GWh for hydrogen and 12 GWh for methane. For supplied energy (Fig. 5-6), for hydrogen it is 17 t-H2 in 2021 and 166 t-H2 in 2030, while for methane it is 43 t-CH4 in 2021 and 428 t-CH4 in 2030. Fig. 5-7 shows the amount of diesel required for transportation of hydrogen and methane for industrial use purposes, which is 1 kL for hydrogen and 0 kL for methane in 2021, and 12 lK for hydrogen and 4 kL for methane in 2030. Fig. 5-8 shows the amount of abated CO2 as a result of introduction of carbon-neutral hydrogen and methane to replace diesel, after subtracting the amount of diesel needed for the transportation of such alternative fuels. Hydrogen requires slightly more diesel in transportation, however, the end result in abatement is almost identical for both hydrogen and methane, which is approximately 163 t-CO2/year in 2021 and 1,600 t-CO2/year in 2030.

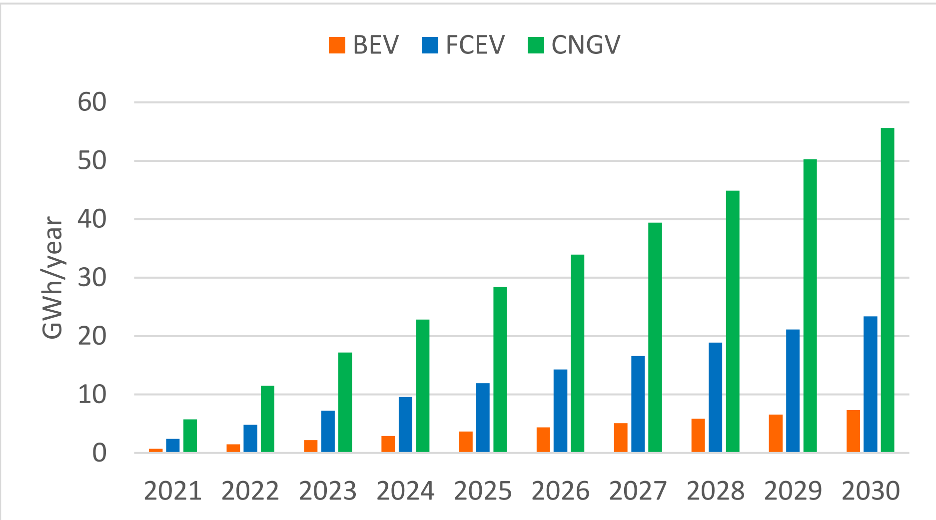


Fig 5-1 Surplus electricity Required for Mobility

Note: BEV, FCEV and CNGV means GE_m, GH_m and GM_m scenario, respectively.

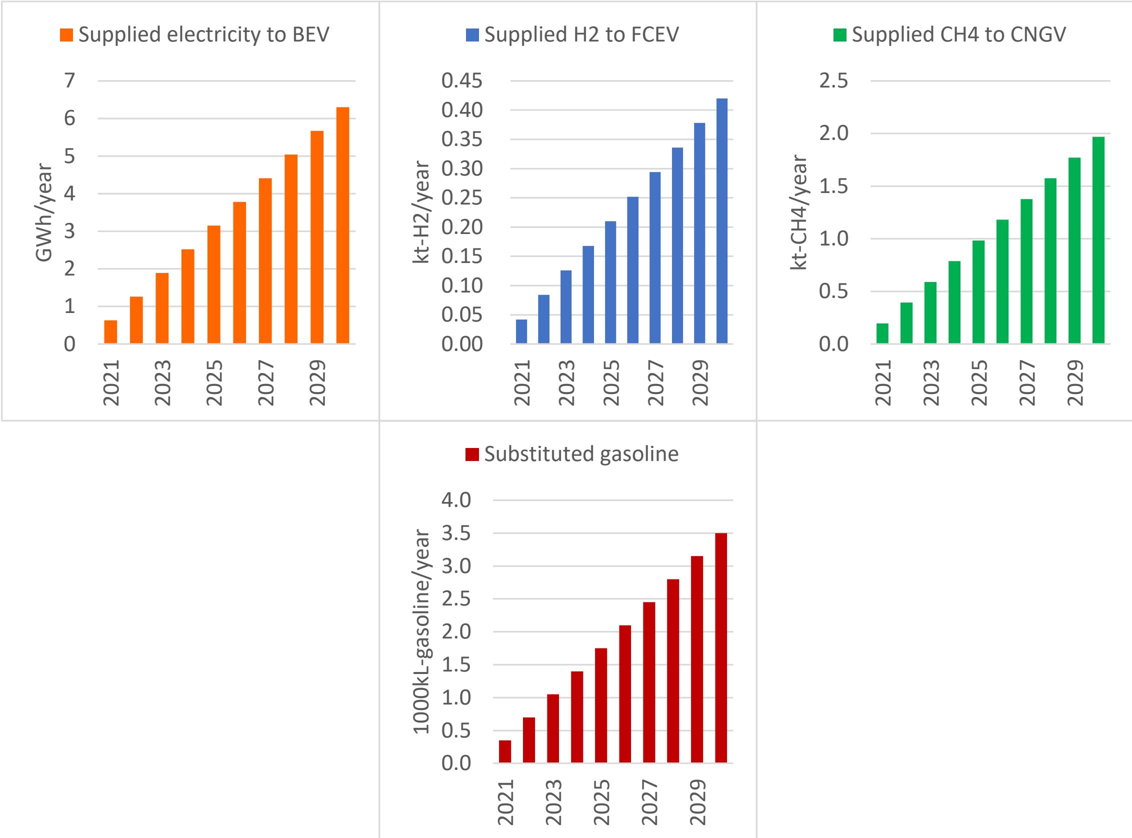


Fig 5-2 Supplied Energy (Electricity, H_2, CH_4) to Mobility and Substituted Gasoline

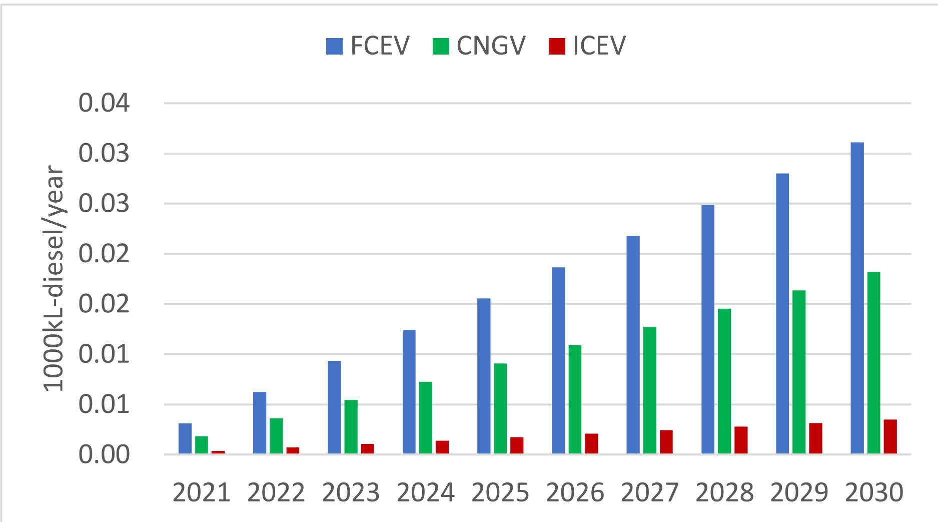


Fig 5-3 Diesel Required for Delivery of H_2, CH_4 and Gasoline for Mobility

Note: FCEV, CNGV and ICEV means GH_m, GM_m and BAU scenario, respectively.

BEV

FCEV

CNGV

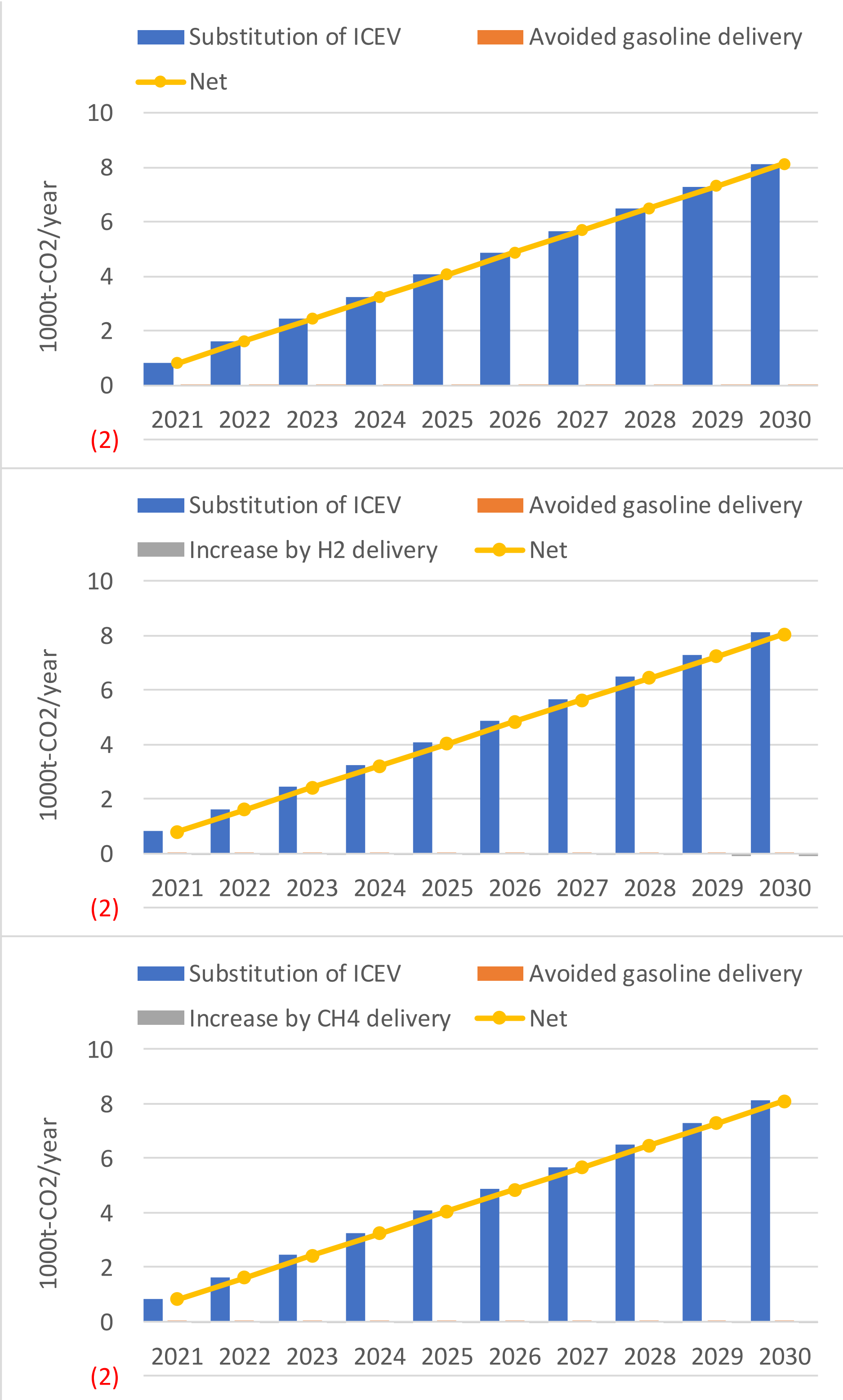


Fig 5-4 Abated CO_2 Emissions in Mobility

Note: BEV, FCEV and CNGV means GE_m, GH_m and GM_m scenario, respectively.

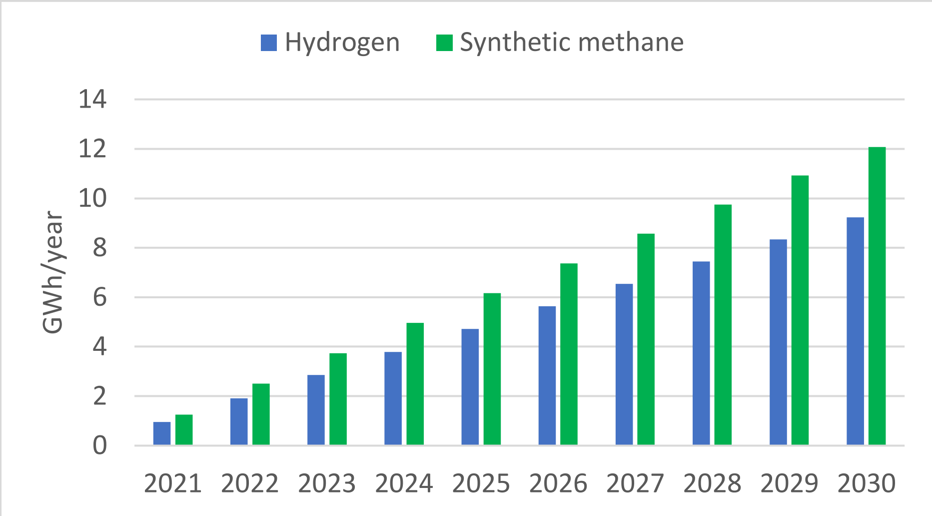


Fig 5-5 Surplus electricity Required for Industry

Note: Hydrogen and Synthetic methane means GH_in and GM_in scenario, respectively.

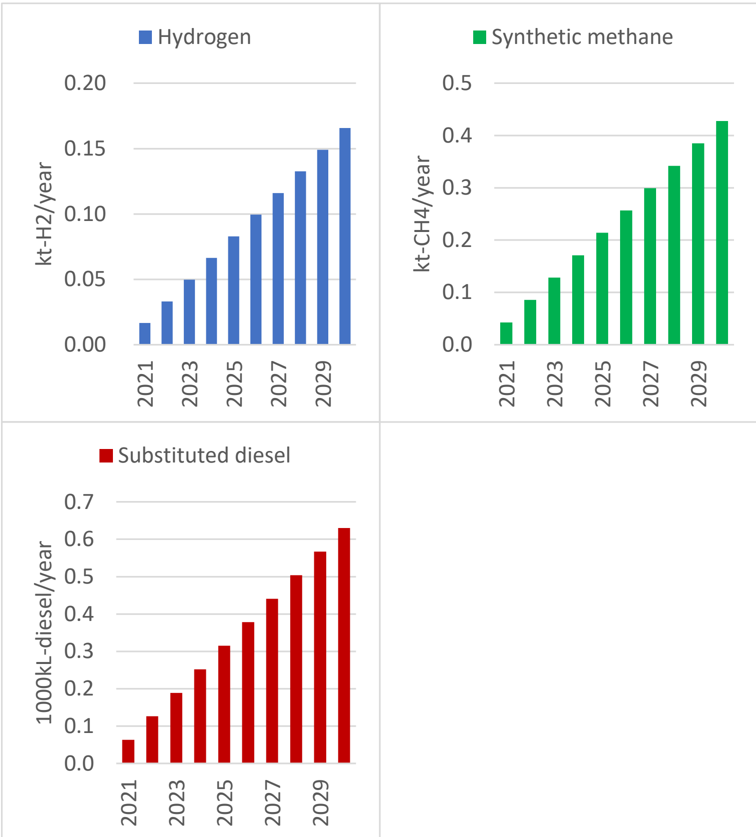


Fig 5-6 Supplied Energy (H_2 and CH_4) to Industry and Substituted Diesel

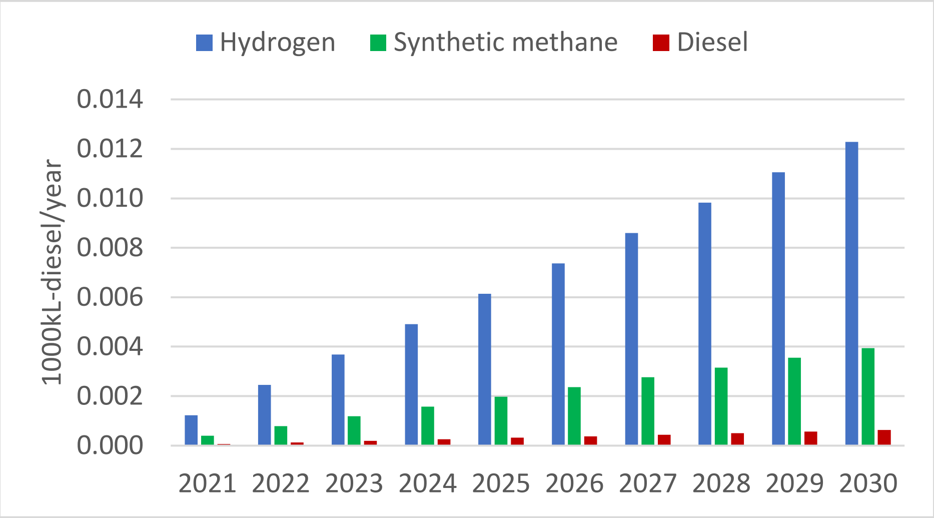


Fig 5-7 Diesel Required for Delivery of H_2, CH_4 and Diesel for Industry

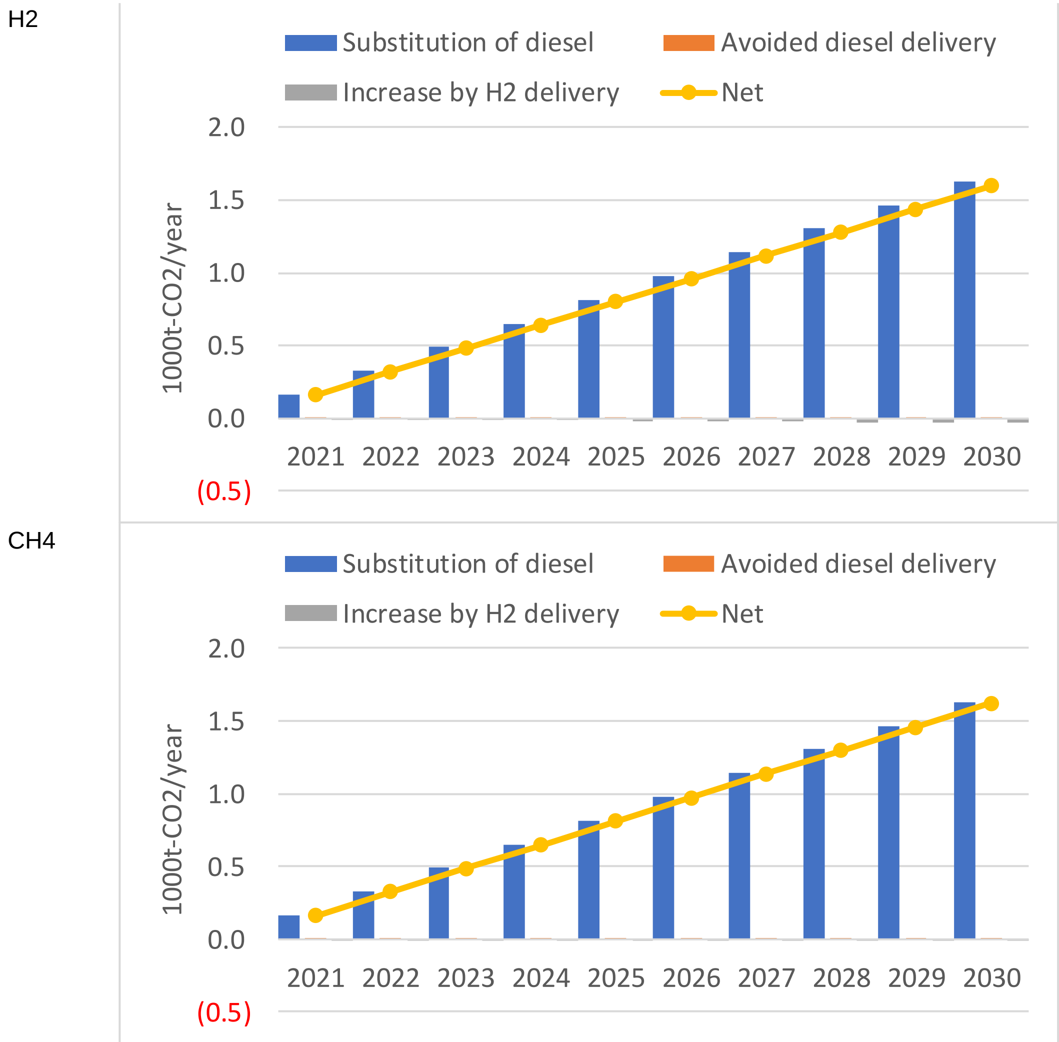


Fig 5-8 Abated CO_2 Emissions in Industry

5.3. Verification of amount of CO_2 required for methanation

Whether sufficient CO_2 is emitted for producing synthetic methane should be verified. Supplied synthetic methane in 2030 is 1,970 t-CH_4 for mobility (Fig 5-2) and 430 t-CH_4 for industry (Fig 5-6). The required CO_2 is 5,400 t-CO_2 and 1,200 t-CO_2, for mobility and industry, respectively. According to the Energy Balance Data of IEA, the CO_2 emission in 2018 from coal-fired power generation, biomass power generation, fossil fuel in industry and biomass in industry is 12,400,000 t-CO_2, 80,000 t-CO_2, 574,000 t-CO_2 and 258,000 t-CO_2, respectively. Although amount of intensive CO_2 emission that is suitable for CO_2 capture required for producing synthetic methane should be identified and geological distances of locations of intensive CO_2 emission and locations of surplus electricity from hydro should be verified, this nationwide CO_2 emission amount can be regarded to be sufficient comparing to the CO_2 required for methanation. In addition, non-energy CO_2 emissions from cement industry can also be expected as CO_2 resources for methanation.

6. Cost and Benefit

Fig 6-1 shows annual investment cost for each scenario for mobility. It is observed that the most dominant factor is vehicle price, as commonly understood. Compared to vehicle prices, the cost of station, delivery, conversion and storage can be regarded as marginal. On the other hand, the benefit gained from substitution of gasoline by BEVs, FCEVs and CNGVs are almost identical, as these vehicles substitute the same number of ICEVs, though energy requirement for delivery of gases is slightly different.

The benefit is expressed by the amount of substituted gasoline (Fig 5-2) by subtracting the additional amount of diesel needed for delivering hydrogen and synthetic methane in comparison with gasoline delivery in BAU (Fig 5-3). For BEVs, the investment cost is 25.2 million USD/year for vehicles, 0.28 million USD/year for storage, 0.09 USD/year for charging stations, and 0.04 million USD/year for power converter for batteries for a total of 25.6 million USD/year. For FCEVs, it is 25.2 million USD/year for vehicles, 0.57 million USD/year for refueling stations, 0.26 million USD/year for delivery, 0.18 million USD/year for electrolyzers, and 0.02 million USD/year for compressors for a total of 45 million USD/year. For CNGVs, it is 15.75 million USD/year for vehicles, 0.42 million USD/year for refueling stations, 0.41 million USD/year for electrolyzers, 0.15 million USD/year for delivery, 0.13 million USD/year for methanation facility, 0.12 million USD/year for CO2 capture facility, and 0.04 million USD/year for storage for a total of approximately 17 million USD/year. For traditional internal combustion engine vehicles, it is 12.6 million USD/year for vehicles, 0.18 million USD/year for refueling stations, and 0.03 million USD/year for deliver for a total of approximately 12.8 million USD/year.

Fig 6-2 shows the annual cost and benefit. The cost is expressed by the difference between annual additional investment cost of scenarios (GE_m, GH_m and GM_m) and that of BAU (ICEVs). The benefit is expressed by the annual net substituted fossil fuel cost. As a result, benefit can be competitive with the cost only in CNGVs case (Fig 6-2), though the benefit can be larger than the cost only after 2030. For Fig 6-2, the cost is estimated at 10 million USD/year for 2021 and 8 million USD/year for 2030, whereas the benefit is 1 million USD/year in 2021 and 2 million USD/year in 2030. For FCEVs, the cost will be 31 million USD/year in 2021 and 20 million USD/year in 2030, and the benefit will be 0 USD in 2021 and 2 million USD in 2030. Lastly, for CNGVs, the cost will be 4 million USD/year in 2021 and 2 million USD/year in 2030, and the benefit will be 0 USD in 2021 and 2 million USD/year in 2030, showing that the cost and benefit of CNGVs almost balances out in 2030.

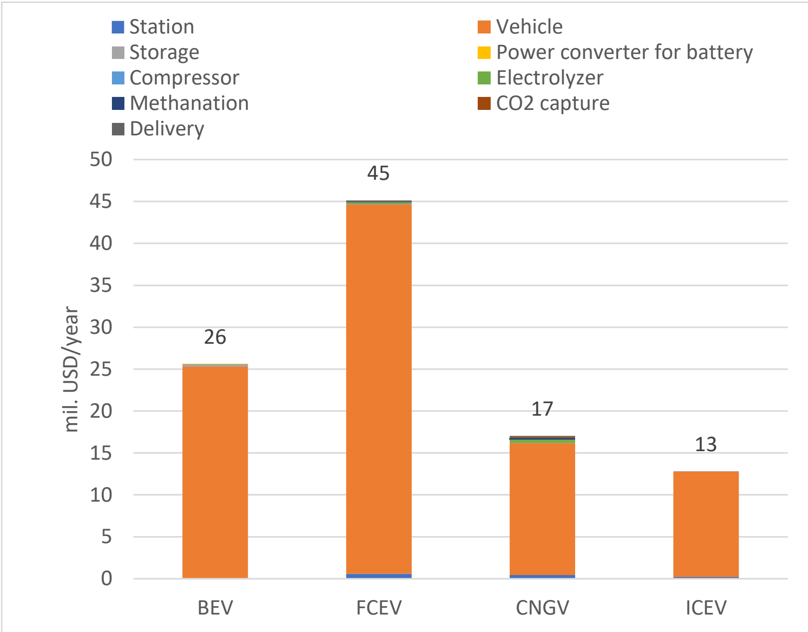
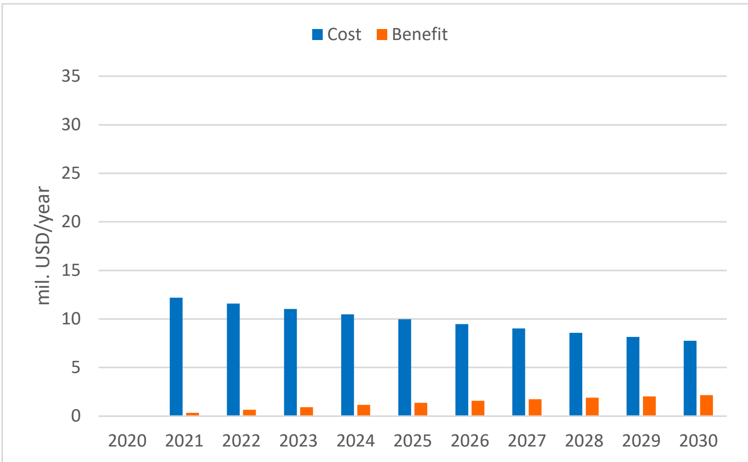


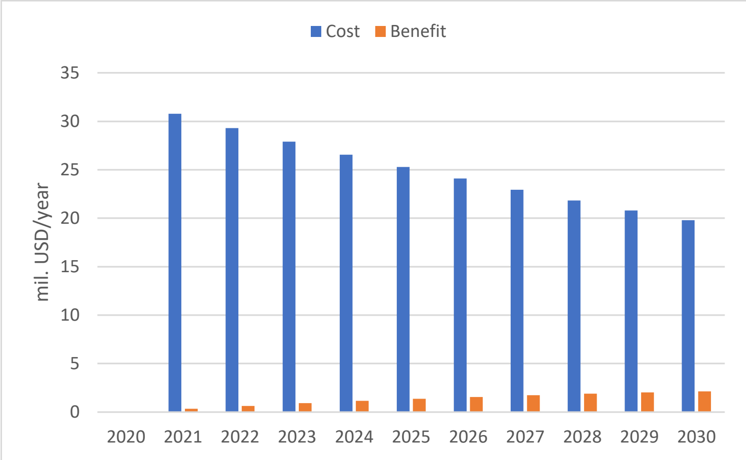
Fig 6-1 Annual Investment Cost for Mobility (nominal price)

Note: BEV, FCEV, CNGV and ICEV means GE_m, GH_m, GM_m and BAU scenario, respectively.

BEV v.s. ICEV (GE_m v.s. BAU)



FCEV v.s. ICEV (GH_m v.s. BAU)



CNGV v.s. ICEV (GM_m v.s. BAU)

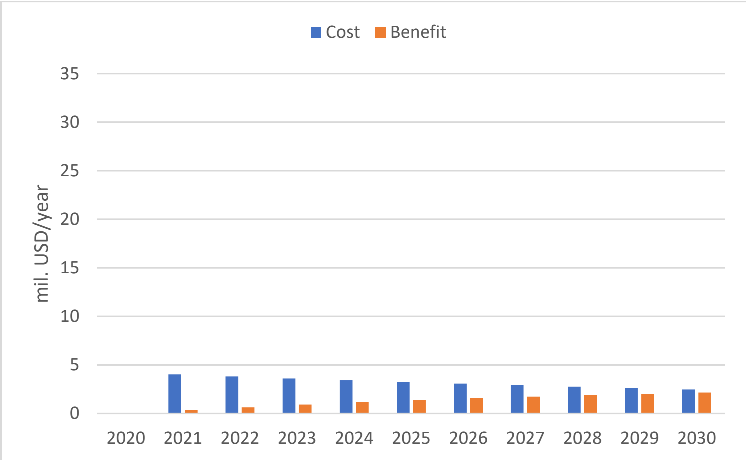


Fig 6-2 Cost and Benefit in Mobility (Net Present Value)

Fig 6-3 shows annual investment cost for each scenario for industry. The cost of delivery dominates in case of hydrogen supply, followed by investment of electrolyzer. For synthetic methane, delivery cost is smaller than hydrogen case (0.1 million USD/year vs. 0.03 million USD/year), but the cost of methanation and CO_2 capture is added and the cost of electrolyzer is larger than hydrogen case (0.07 million USD/year vs. 0.09 million USD/year). As a result, the cost of synthetic methane is slightly higher than that of hydrogen (0.182 million USD/year vs. 0.188 million USD/year). Fig 6-4 shows the cost and benefit of the two cases, where there is no large difference observed between two scenarios (GH_in and GM_in). Unlike mobility sector, as the industrial sector does not need additional investment (such as vehicles and stations), the benefit exceeds the cost much faster than the mobility sector. More precisely, the cost of hydrogen is 0.16 million USD/year in 2021 and 0.09 million USD/year in 2030, and the benefit is 0.05 million USD/year in 2021 and 0.38 million USD/year in 2030. For synthetic methane, the cost is 0.17 million USD/year in 2021 and 0.08 million USD/year, and the benefit is 0.06 million USD/year in 2021 and 0.38 million USD/year in 2030.

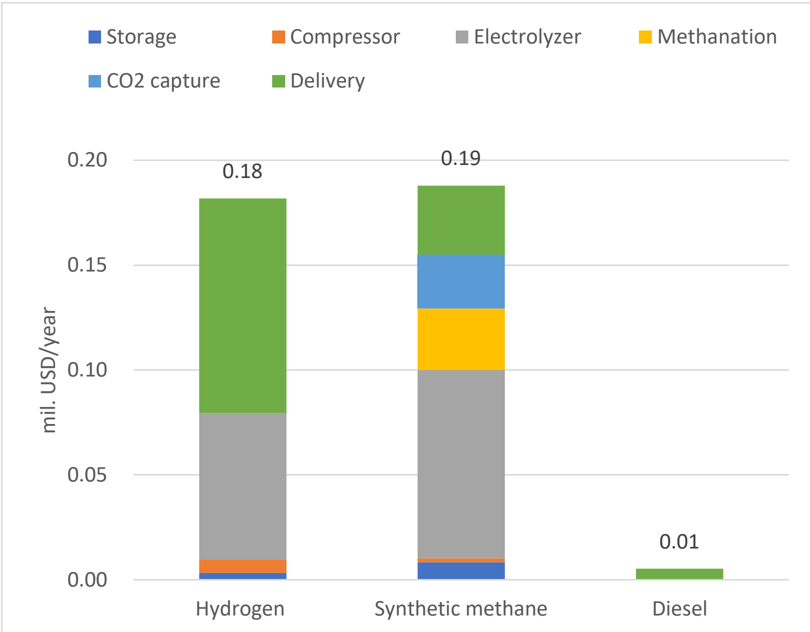
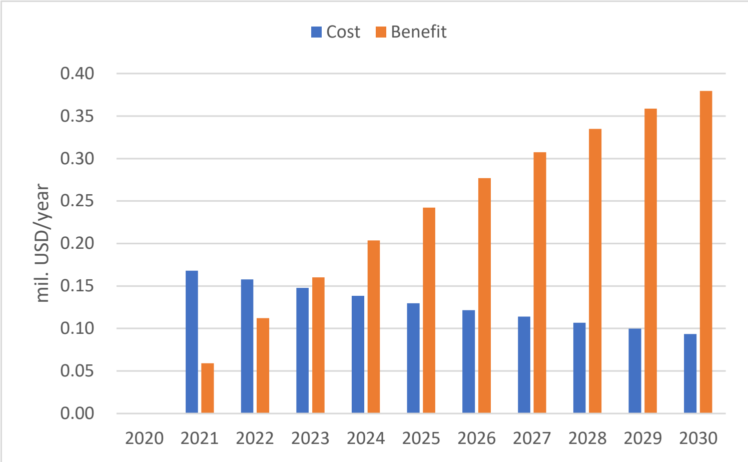


Fig 6-3 Annual Investment Cost for Industry (nominal price)

Hydrogen v.s. Diesel (GH_in v.s. BAU)



Synthetic methane v.s. Diesel (GM_in v.s. BAU)

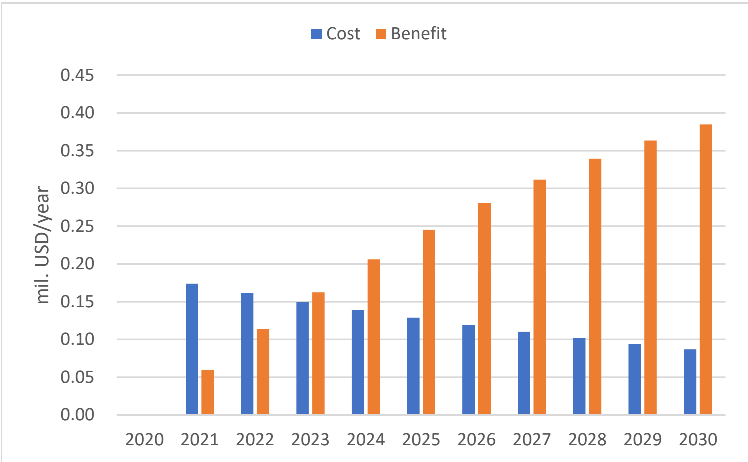


Fig 6-4 Cost and Benefit in Industry (Net Present Value)

7. Implication to Masterplan

7.1. Summary from Cost Benefit Analysis

(1) Mobility

Among the scenarios, GH_m (surplus electricity to hydrogen and to FCEV substituting ICEVs), GM_m (surplus electricity to hydrogen and synthetic methane and to CNGVs substituting

ICEVs), GE_m (surplus electricity to BEVs substituting ICEVs), the most cost-effective scenario is GM_m according to CBA. As commonly understood, the dominant factor of economics of mobility is vehicle price. Although the CAPEX required to produce synthetic methane is much greater than the CAPEX of hydrogen production and stationary battery, the vehicle cost of CNGVs is much smaller than that of FCEVs and BEVs. This is the reason why the scenario of GM_m is the most cost-effective option in terms of the national cost-benefit.

However, it should be noted that this result makes sense only if the vehicle price of CVGVs is sufficiently less expensive than the price of FCEVs and BEVs.

Even in the GM_m scenario, it is not until 2030 that the benefit from reducing import of petroleum products exceeds the cost incurred by majorly investment.

(2) Industry

For the industry, huge difference in cost and benefit is not observed between GH_in (surplus electricity to hydrogen substituting petroleum products) and GM_in (surplus electricity to hydrogen and to synthetic methane substituting petroleum products). The delivery cost of hydrogen in GH_in is offset by the cost of electrolyzer, methanation and CO_2 capture in GM_in.

7.2. Implication to masterplan

Based on the CBA, GM_m (synthetic methane to CNGVs) scenario should be chosen for Laos, if surplus electricity from hydro is to be used for the mobility. If surplus electricity from hydro is to be used for the industrial sector, either GH_in (hydrogen) or GM_in (synthetic methane) can reasonably be chosen as there is not a huge difference in cost and benefit between the two cases.

As the scenario GH_in or GM_in shows that the benefit exceeds the cost faster than GM_m, it is recommended that supply of green gases to industry should be carried out at first, followed by supply of green synthetic methane to mobility.

According to the energy balance data of IEA, the fossil fuel consumption in 2018 is 1,014 ktoe (diesel and gasoline) in the transport (mobility) sector, and 57 ktoe (diesel and heavy oil) in the industrial sector. Decarbonizing the industrial sector by green gases from surplus electricity from hydro is easier to be achieved. In addition, if surplus electricity is assumed to be 3,000 GWh from which the synthetic methane can be produced and supplied to about 300,000 CNGVs, 137 ktoe of petroleum products can be reduced.

However, to realize decarbonizing mobility and industrial sectors, there are challenges to be overcome. First, applications that are suitable for hydrogen or synthetic methane in the industrial sector should be identified. For boiler application, there is no problem to use hydrogen, as hydrogen-boilers are already developed and commercialized. But, for direct heating and burning, some of the applications need carbon content in gases and hydrogen cannot be applied, such as ultra-high temperature heating and carburizing.

As for the mobility, vehicle price of CNGVs should be much less expensive than FCEVs and BEVs and slightly expensive than ICEVs. CNGVs should be modified from ICEVS or newly developed.

In order to realize the production and supply of green gases to either industry or mobility, the specific sites of hydrogen production from surplus electricity from hydro and those of carbon capture from coal-fired power plants, biomass power plants or industry should be identified.

Lastly, it should be noted that the CBA was carried out with an assumption that the surplus electricity from hydro power that would otherwise be discarded can be used for production of green gases and that the cost of this surplus electricity is imposed the power sector no matter whether the surplus electricity can be use or not. In reality to conduct business, the price of surplus electricity is determined by negotiation between power sector and gas producers, which affects the sales price of gases to consumers.