Chapter 2

A Model Case Study: CCUS Cost Estimation

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Chapter 2

A Model Case Study: CCUS Cost Estimation

1. Background and Introduction

This model case study (MCS) for a CCS project at a CO2-intensive industrial facility in the ASEAN region, such as a coal-fired power plant, was conducted to help visualise the whole value chain of a full-scale CCS project – from capturing to storing the CO2 at its final destination. Based on public source information, the case study provides a preliminary financial analysis for the main technical segments of a full-scale CCS project.

The study aims to better understand CCS in general by analysing the basic cost structure of a hypothetical project and offer input for future policy and regulatory changes that can support and accelerate CCS implementation in the ASEAN region and other member countries of ACN on a larger scale.

2. Survey of Previous Studies

Over the decades, CCS has gained recognition as a key technology to achieve climate targets. Much time and effort worldwide have been dedicated to evaluating CCS strengths and challenges. As part of those efforts, many studies have already been conducted to analyse the cost structure of CCS projects in general or for specific components of the CCS value chain in particular. The analytical work on breaking down the cost structure on a common formula, with a detailed evaluation of each component, has been limited so far. This is partly because the deployment of commercial CCS facilities is still limited. Another reason is that project-specific factors have a big impact on all components of the CCS value chain. How much is the additional energy cost needed to operate the CCS facility? On what kind of terrain will the pipeline be built? How deep must the well be? These are just a few factors that can easily double the cost of each affected component. Economies of scale are another important factor for the cost optimisation of CCS.

A major work on this matter is GCCSI's report, published in the first quarter of 2021. It examines the technology readiness of each component of the CCS value chain and reviews the factors that influence the cost of carbon capture, compression, transport, and storage. The study offers various cost scenarios for different emitting sources in type and scale. For coal power plants with a capture capacity of 0.18 to 1.8 MtCO2 per year, the study estimates a capture cost range of about US$50–US$65 per tonne CO2, with a clear tendency of lower costs for larger plants.

Another important work on CCS costs is RITE's 'Report on Carbon Dioxide (CO2) Fixation and Effective Utilisation Technology: Results of the CO2 Underground Storage Technology Research and Development Project'. It dates back to 2005, but it is probably the most detailed analysis of the costs of a full-scale CCS project. The report offers a comprehensive breakdown of the capturing site for different emitting sources, such as a newly constructed coal power plant, a retrofitted coal power plant, or a steelworks plant. The estimated capturing costs for those plants range from about US$30 to US$60/t-CO2. The publication year might give an outdated impression, but the detailed and comprehensive content makes this report a unique work in CCS cost analysis. The report is still a reference in newer studies as Japan CCS Co., Ltd. (JCCS)' demonstration project in Tomakomai.

'The Cost of CO2 Capture and Storage' (Rubin et al., 2015) well overviews the cost changes affecting the full CCS value chain over 10 years starting in 2005. It updates the costs reported in the 2005 Intergovernmental Panel on Climate Change's *Special Report on Carbon Dioxide Capture and Storage* by comparing the costs to recent studies focusing on electric power plants. The study offers an excellent overview of cost ranges for a wide variety of scenarios, depending on combustion and capturing technology, as well as differences between newly built plants and retrofits.

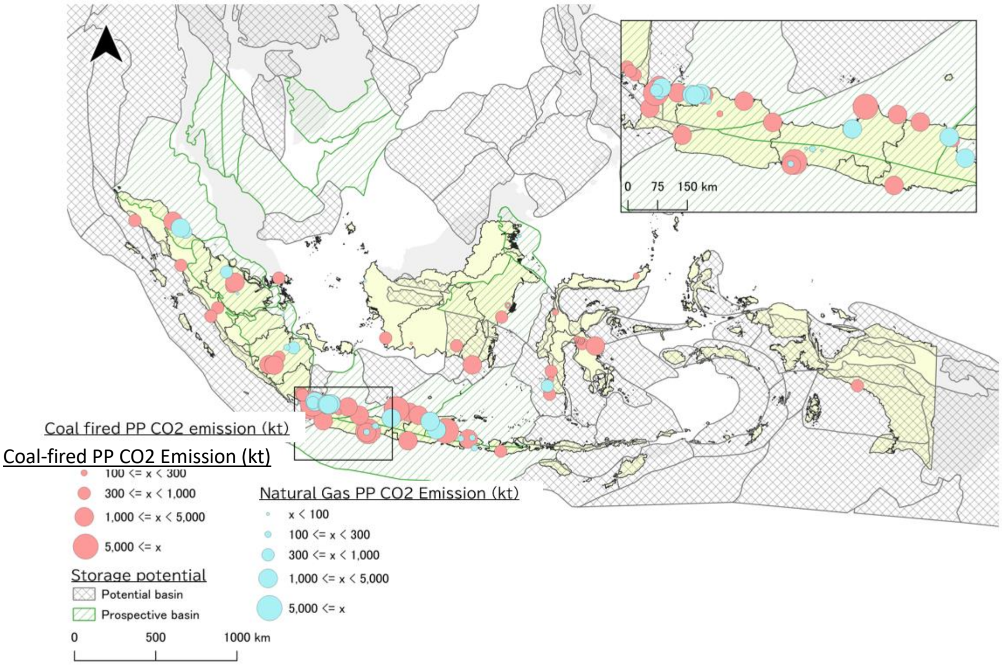
3. Region Selection

The study team considered several ASEAN member countries for the model project. Indonesia was chosen due to its position as a major oil, gas, and coal producer. In addition, Indonesia is by far the biggest ASEAN member population-wise; about 40% of the ASEAN population lives in Indonesia.

After selecting the country, the study team analysed the distribution of gas and coal-fired power plants within Indonesia. Figure 2.1 shows that most power plants are located in Java. Additionally, GCCSI data gave a big picture of the potential basins in this area. The data showed a wide-ranging potential for subsurface CO2 storage around Java.

The high density of CO2-intensive sources and the good accessibility to storage potential were key requirements in selecting the region. These requirements were both met in Java.

Figure 2.1: The Java Region of Indonesia as a Suitable Terrain for the CCS Model Case Study



Source: Created by the Author, storage information provided by GCCSI.

The definite location was further narrowed down by analysing existing reservoir examination reports. The reservoir characterisation and simulation by Tsuji et al. (2013) showed that the Blora Regency of the Central Java Province (see red box in Figure 2.2) offers suitable conditions to safely store the captured CO2 with a sandstone formation of over 1,000 m depth.

Figure 2.2: Map of Java Island, Indonesia, with Coal-fired Power Plants in Operation

Note 1: The Author added the red box described as the 'Selected Area' to visualise the targeted location for the model case.

Note 2: The numbers in the brown circles describe the number of operating units at that location.

Source: Global Energy Monitor, Global Coal Plant Tracker, https://globalenergymonitor.org/projects/global-coal-plant-tracker/tracker/ (accessed 29 October 2021).

4. Specifications and Characteristics of the Model Project

After the regional conditions were determined, the technical specifications and characteristics of the model project were defined. As many ASEAN members still rely on coal-fired power plants as a relatively cheap energy supplier, there is a real demand for retrofitting existing power plants with carbon capture technology. The study team decided to take a medium-scale ultra-supercritical coal-fired power plant as an example for the MCS, as they are likely to be the last ones to be shut down.

It will be a 500-megawatt (MW) plant, with an expected lifespan of 25 years after the retrofit. A capacity factor of 80% and a thermal efficiency of 40% were applied. Chemical absorption–based capture technology using monoethanolamine with a capture rate of 90% was chosen, being one of the best-proven capture technologies over the past decades.

The captured CO2 will be transported to the injection well at a deployed gas field through a 50 km onshore pipeline. The lithology at the selected area is a sandstone formation of about 2,000 meters.

Table 2.1: Specifications and Characteristics of the Model Project

Capacity	500 MW
Type of Power Plant	USC coal
Capacity Factor	80%
Thermal Efficiency	40%
Default Emission Factor for Lignite	101,000 kgCO2/TJ
Fuel Consumption	31,536 TJ
Type of Capture Technology	Chemical absorption (Amine)
Capture Efficiency	90%
Estimated CO2 Emission	3.19 MtCO2/y
Captured CO2	2.87 MtCO2/y
Pipeline Length	50 km
Pipeline Design	12 in
Well Depth	2,000 m
Project Lifespan	25 years

TJ = tera joule, USC = ultra supercritical.

Source: Created by the Author. Default Emission Factor for Lignite taken from IPCC (2006).

5. Capture Costs

The cost analysis was split into the three obvious components of the CCS value chain: capturing, transporting, and sequestering CO2.

RITE's 'Report on Carbon Dioxide Fixation and Effective Utilisation Technology: Results of the Carbon Dioxide Underground Storage Technology Research and Development project' was used as a reference to analyse the capture costs. It is an older study dating back to 2005. However, due to the detailed and comprehensive breakdown of all components of a CCS project, its results are still used as a reference in several feasibility studies and demonstration projects, such as the Tomakomai Demonstration Project. RITE's study offers multiple scenarios, including a basic cost breakdown of a capturing site at a retrofitted coal-fired power plant, with a generation capacity of 540 MW and a capture capacity of 1 MtCO2/year. All costs are calculated with an annual expense ratio of 9% and repair costs of 3%. The evaluation does not include CAPEX Labour.

Table 2.2: Capture Costs: a Basic Case Study

	Category	Component	Unit	Cost
CAPEX	Equipment	Supporting boiler	US$ million	91.94
		Higher desulphurisation	US$ million	10.2
		Other related equipment	US$ million	48.75
	Total		**US$ million**	**150.89**
OPEX	Operation of supporting boiler	Fuel	US$ million /y	8.35
		Other variable costs	US$ million /y	1.62
	Absorbent	Amine	US$ million /y	2.53
	Desulphurisation	NaOH (sodium hydroxide)	US$ million /y	0.63
	Labour		US$ million /y	18.1
	Total		**US$ million /y**	**31.23**

CAPEX = capital expenditure.
Note: US dollars (2005), Calculated from ¥ to $ with yearly average TTS rate (111.21) of MUFG.
Source: Created by the Author based on RITE (2005).

The three major carbon capture technologies – pre-combustion CO_2 capture, post-combustion CO_2 capture, and oxyfuel CO_2 capture – are primary adaptions of conventional combustion systems.

Pre-combustion	• Separation of CO_2 by converting fuel into a gaseous mixture of hydrogen and CO_2 before main energy conversion, produced by gasification of solid fuels or reforming of gases • Applied in natural gas processing; only applicable for power generation in case of newly built projects
Post-combustion	• Separation of CO_2 using a liquid solvent carried out downstream of a largely unchanged conventional combustion process, comparable to the wet desulphurisation of flue gases • Often applied in the food and beverage industry; applicable for retrofitting power plants
Oxyfuel	• Combustion of carbonaceous fuels with (nearly) pure oxygen, resulting in flue gas of CO_2 and water vapour from which storable CO_2 is recovered by simple drying

As this model project targets to retrofit a coal-fired power plant, the post-combustion capture method will be applied. RITE's numbers were adjusted and scaled up to a capture capacity of 2.87 $MtCO_2$ per year to calculate the capture cost of the model plant. The supporting boiler is the most cost-intensive component within the CAPEX breakdown. Additional components for such a system may include an absorber, desorber, condenser, and other heat exchange equipment.

Fuel and labour have the biggest impact on operating costs. Obviously, the amine absorbent is also an important factor.

Table 2.3: Capture Costs Breakdown

Cost Factor	Category	Component	Unit	Cost
CAPEX	Equipment	Supporting boiler	US$ million	263.87
		Higher desulphurisation	US$ million	29.27
		Other related equipment	US$ million	139.91
	Total		US$ million	433.05
OPEX	Operation of supporting boiler	Fuel	US$ million /y	23.96
		Other variable costs	US$ million /y	4.65
	Absorbent	Amine	US$ million /y	7.26
	Desulphurisation	NaOH (Sodium hydroxide)	US$ million /y	1.81
	Labour		US$ million /y	51.95
	Total		US$ million /y	89.63
Unit cost			US$/t	37.27

Note: US dollars (2005), calculated from ¥ to $ with yearly average TTS rate (111.21) of MUFG.
Source: Created by the Author based on RITE (2005).

6. Transportation Costs

Multiple studies that examined the cost of CO2 transportation were compared and analysed.

Even though CO2 pipelines are designed for higher pressure than common gas pipelines, these are a relatively mature technology, with multiple thousand miles already in operation (Smith et al., 2021). Pipeline costs are highly variable, depending on the type of terrain, infrastructure crossings, and other factors (Table 2.4). The following table appeared in the National Energy Technology Laboratory (NETL) report as an example of typical rule-of-thumb costs for various terrains, as quoted by a representative of Kinder Morgan at the Spring Coal Fleet Meeting in 2009. The cost range is from US$50,000/mile up to US$700,000/mile.

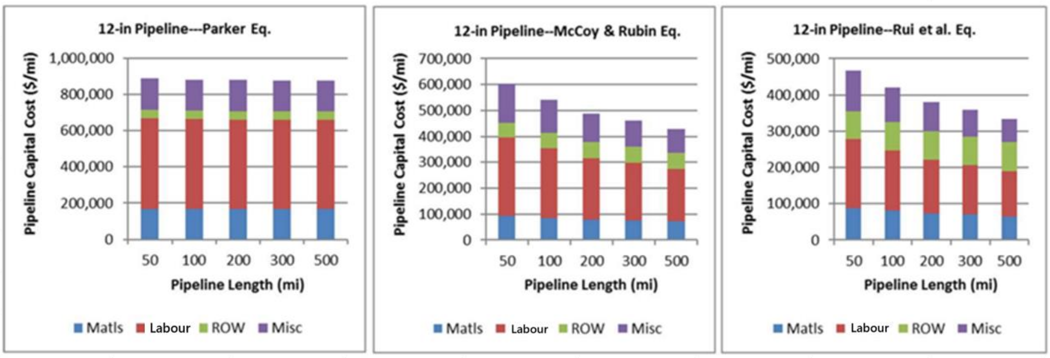
Table 2.4: Transportation Costs (US$)

Terrain	CAPEX
Flat, dry	50,000
Mountainous	85,000
Marsh, wetland	100,000
River	300,000
High population	100,000
Offshore (150–200 ft depth)	700,000

Source: NETL (2017).

In 2018, the NETL designed an Excel-based mathematical model to calculate the cost breakdown for a CO2 pipeline. The model offers the possibility of getting multiple cost estimation patterns (Figure 2.3) by filling in the necessary variables, such as pipeline length, diameter, capture capacity, etc.

Figure 2.3: Breakdown of Natural Gas Pipeline Capital Costs Using Different Equations



Note: Author changed 'Labor' to 'Labour' for consistency.
Source: NETL (2018a).

Using NETL's model, the potential costs of a 50 km long, 12-inch pipeline were calculated (Table 2.5). The Blora Regency, targeted as the storage destination of this project, is characterised by hilly, densely vegetated forests and agricultural lowlands ranging from 25 to 500 meters above sea level. The geographical conditions are important cost-driving factors, as stated earlier. Considering the difficult terrain, Parker's calculation model, which was the most expensive result out of the three options, was chosen for this project.

Next to the apparent costs like labour, materials, and pumps, it is important to consider the right-of-way costs and damages. Included components are highly corrosion-resistant pipelines, pigging facilities, line break valves (usually installed at an interval of 10 km each), monitoring, and control facilities.

Table 2.5: Pipeline Capital Costs (US$)

	CAPEX (Parker)	CAPEX (McCoy)	CAPEX (Rui)
Materials	5,233,256	2,991,604	2,897,806
Labour	15,605,339	10,277,736	6,501,388
Right-of-way and damages	1,511,438	1,723,411	2,313,738
Miscellaneous	5,390,104	5,117,930	3,885,668
CO_2 surge tanks	1,244,744	1,244,744	1,244,744
Pipeline control system	111,907	111,907	111,907
Pumps	1,468,064	1,468,064	1,468,064
Total	**30,564,853**	**22,935,396**	**18,423,315**

Source: NETL (2018b).

Operating costs (OPEX) are relatively project-specific. Existing documents do not uniquely define the exact operating expenditure for operations and maintenance of the assets. The total OPEX also includes elements related to overhead and allocation of costs from other functions and their equipment. Annual operating costs, such as fuel for the compressor stations, repair and pigging costs, information technology, and telecommunications, should be considered.

Usually, a share of the capital costs of 3.5% is applied for a common onshore gas pipeline, as stated in Ulvestad and Overland (2012). The OPEX for the model project's CO_2 transportation was also calculated using NETL's model (Table 2.6). The energy costs for the pumps are the biggest cost-driving factor, responsible for almost 70% of the transportation OPEX.

Table 2.6: Pipeline Operating Costs (US$)

	OPEX
Pipeline operations and maintenance	262,784
Pipeline related equipment and pumps	112,989
Electricity costs for pumps	748,898
Total	**1,124,671**

Source: NETL (2018b).

In total, the unit cost for the transportation component is US$0.82/t-CO2.

Table 2.7: Pipeline Unit Cost

	Cost Components	Unit	Cost
CAPEX	Materials	US$ million	5.23
	Labour	US$ million	15.61
	Right-of-way and damages	US$ million	1.51
	Miscellaneous	US$ million	5.39
	CO2 surge tanks	US$ million	1.24
	Pipeline control system	US$ million	0.11
	Pumps	US$ million	1.47
	Total	US$ million	30.56
OPEX	Pipeline O&M	US$ million /y	0.26
	Pipeline-related equipment and pumps	US$ million /y	0.11
	Electricity costs for pumps	US$ million /y	0.75
	Total	US$ million /y	1.12
Unit Cost		US$/t	0.82

Source: Created by the Author based on the results of NETL's calculation model.

Besides pipelines, shipping is a major transportation option for longer distances. The CO2 chain for ship transport of CO2 includes liquefaction at the capture site, intermediate storage before transport, loading, transport, and unloading. Costs of a marine transport system comprise many elements. Besides ships, investments are required for loading and unloading facilities, intermediate storage, and liquefaction units. Further costs are for operation (such as labour, ship fuel and electricity, harbour fees) and maintenance.

For marine transport, CO2 is liquefied before being loaded onto ships to reduce its volume. It is cooled down from 0°C to -20°C and compromised from about 2 kg/m3 to about 1,100 kg/m3, which is 1/550 in volume. This means a CO2 ship must carry more mass than an equivalent LNG or LPG ship, where the cargo density is about 500 kg/m3.

The downside of CO2 shipping is that marine transport induces more associated CO2 transport emissions than pipelines due to additional energy use for liquefaction and fuel use in ships.

Table 2.8 shows the results of the Zero Emissions Platform study, which estimated the costs for a 'point-to-point' transport case by ship, with 2.5 Mtpa CO2 to storage sites on a distance of 180, 500, 750, and 1,500 km.

Table 2.8: Transport Cost by Shipping

	180 km	500 km	750 km	1,500 km
Number of ships	1	1	1	1
Ship size in m3	22,000	29,300	36,600	25,700
CAPEX (US$ million)	193.36	218.82	243.06	297.95
Annual costs (US$ million /y)	46.95	51.39	55.22	68.99

Note: Costs calculated using the average exchange rate of 2011 from euros to US dollars (US$1.3924)
Source: ZEP (2011).

The estimations mainly consider coaster ships, targeting mid-range transportation for a limited area close to the coast. The CAPEX for such a ship for the widest available range was estimated at US$297.95 million, with an annual expenditure of US$68.99 million. The given range of 1,500 km would cover only a limited area of Indonesia, as shown with a red circle in Figure 2.4. In creating a vast network range covering the whole ASEAN community, many member states of which are separated by sea, it is inevitable to have a fleet of CO2-transport ships that can cover at least a distance of 3,000–5,000 km. At this stage, further improvements will be essential to lower the cost for large-scale, long-range shipping to a feasible level.

Figure 2.4: Geographical Range of 1,500 km in Indonesia

Note: The Author added the red circle and distance of the radius to visualise the range of the ships.
Source: HERE WeGo Maps.

7. Storage Costs

In the storage cost model, multiple stages must be considered. Much subsurface research must be done in the site screening and selection phases, which usually take several years to complete. The duration for permitting depends strongly on the country where the project takes place.

The technologies and equipment used for geological storage are widely used in the oil and gas industries. However, there is a significant range and variability of costs due to site-specific factors, especially if the injection site is onshore or offshore and depending on the reservoir depth.

As for the capture component, RITE's study was a good reference in calculating the storage costs. The study offers multiple cost scenarios for different site specifications (Table 2.9). All costs are calculated with an annual expense ratio of 9% and repair costs of 3%.

Table 2.9: Storage Costs

Type (Water Depth)	Distance from Coast (km)	Depth of Sink (m)	Drilling Costs 100 kt/y Well (US$ million)	Drilling Costs 500 kt/y Well (US$ million)	Offshore Pipeline (US$ million)	Onshore Engineering (US$ million)
Onshore	0	1,000	62.9	12.6	0	0
Onshore	0	2,000	122.3	24.3	0	0
Offshore (30 m)	20	1,000	161.9	40.5	24.3	4.5
Offshore (30 m)	20	2,000	261.7	60.2	24.3	4.5
Offshore (30 m)	20	3,000	344.4	76.4	24.3	4.5
Offshore (150 m)	70	1,000	162.8	40.5	89.9	4.5
Offshore (150 m)	70	2,000	262.6	60.2	89.9	4.5
Offshore (150 m)	70	3,000	345.3	76.4	89.9	4.5

Note: US dollars (2005), calculated from ¥ to $ with yearly average TTS rate (111.21) of MUFG.
Source: RITE (2005).

Besides the sink depth, well size and distance from the coast are very important factors immensely impacting the total storage costs. This model project's case will be an onshore storing site with a well depth of 2,000 m.

Six 500 kt/year wells will be drilled to store the estimated yearly emissions of 2.87 $MtCO_2$/year. Tables 2.10 and 2.11 show the CAPEX for onshore drilling, pre-exploration of the storage site, compressor stations, and OPEX for continuous monitoring. Operating costs for the compressors are not included.

Table 2.10: Drilling Costs and Total CAPEX for Wells

Type	Depth of Sink (m)	Drilling Costs 500 kt/Well (US$ million)	Number of Wells	Total CAPEX for Wells (US$ million)
Onshore	2,000	24.3	6	145.8

Source: Created by the Author. Based on RITE (2005).

RITE calculated additional fixed costs for each well (Table 2.11).

Table 2.11: Additional Fixed Costs for Each Well

Cost Factor	Unit	Costs (US$ million)
Pre-exploration of site, including 3D modelling	US$ million	7.76
Compressor station	US$ million	12
Monitoring	US$ million /y	4.42

Source: RITE (2005).

Combined with the high variability of costs depending on the actual subsurface situation and the fact that the operating costs for the compressor station are not included, it can be assumed that the actual unit cost can rise to double the US$12.92/t-CO2 (Table 2.12).

Table 2.12: Unit Cost of Storage Components

	Cost Factor	Unit	Costs (US$ million)
CAPEX	Wells	US$ million	145.8
	Pre-exploration of site, including 3D modelling	US$ million	46.56
	Compressor station	US$ million	72
	Total	US$ million	264.36
OPEX	Monitoring	US$ million	26.52
Unit Cost		US$/t	12.92

Source: Created by the Author.

8. Applying Plant Cost Index (PCI) Development

As various sources date from different years, a PCI published by Japan's METI was applied to adjust the costs to the year 2020. The baseline at this index is set at 100 for the year 2000. Table 2.13 shows the adjusted unit cost for each component. The total unit cost for this model project is US$62.8/t-CO2.

Table 2.13: Plant Cost Index (PCI)

Year	PCI			
2005	130.0			
2011	137.6			
2020	160.2			
	Capture	Transport	Storage	Total
Unit Cost before adjustments (US$/t-CO2)	37.27	0.82	12.92	51.01
Unit Cost after adjustments (US$/t-CO2)	45.92	0.95	15.93	62.80

Source: JMCTI (2020).

9. Summary of Cost Estimation

Breakdown-wise, the capture costs are the most expensive, over 70%. The additional energy consumption especially has a huge impact on the total costs over the project's lifespan. The associated CO2 emissions, due to additional energy usage, are also an important point to be improved to increase the carbon reduction potential of CCS.

Transportation costs are minimal, which is no surprise, considering the short distance and all parts are onshore. However, as mentioned earlier, storage costs can rise significantly, so the cost balance between capture and storage might differ.

Table 2.14 shows the capture cost is the most expensive component, with over 70% of the overall costs. Transportation costs are minimal due to the short distance, and all parts are onshore. Depending on the storage location, storage costs can rise significantly, so the cost balance between capture and storage might differ in other cases.

Table 2.14: Cost Breakdown Ratio by Component

	Capture	Transportation	Storage
US$/t-CO2	45.92	0.95	15.93
%	73.12	1.52	25.36

Source: Created by the author.