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Research paper

Potential economic benefits of carbon dioxide (CO_2) reduction due to renewable energy and electrolytic hydrogen fuel deployment under current and long term forecasting of the Social Carbon Cost (SCC)

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HIGHLIGHTS

- The first scenario proves a reduction in fossil fuel consumption as a result of renewable energy integration.
- CO_2 emissions from power and transport sectors are reduced.
- In the second scenario, the production and export of fossil fuel continues (for revenue generation purposes) even after renewable resources have been fully integrated into the Libyan power system.
- The second scenario is better than proves more beneficial the first, especially for the 2015-Cost scenario is applied.

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ABSTRACT

The 2016 Paris Agreement (UNFCCC Authors, 2015) is the latest of initiative to create an international consensus on action to reduce GHG emissions. However, the challenge of meeting its targets lies mainly in the intimate relationship between GHG emissions and energy production, which in turn links to industry and economic growth. The Middle East and North African region (MENA), particularly those nations rich oil and gas (O&G) resources, depend on these as a main income source. Persuading the region to cut down on O&G production or reduce its GHG emissions is hugely challenging, as it is so vital to its economic strength. In this paper, an alternative option is established by creating an economic link between GHG emissions, measured as their CO_2 equivalent (CO_2e), and the earning of profits through the concept of Social Carbon Cost (SCC). The case study is a small coastal city in Libya where 6% of electricity is assumed to be generated from renewable sources. At times when renewable energy (RE) output exceeds the demand for power, the surplus is used for powering the production of hydrogen by electrolysis, thus storing the energy and creating an emission-free fuel. Two scenarios are tested based on short and long term SCCs. In the short term scenario, the amount of fossil fuel energy saved matches the renewable energy produced, which equates to the same amount of curtailed O&G production. The O&G-producing region can earn profits in two ways: (1) by cutting down CO_2 emissions as a result of a reduction in O&G production and (2) by replacing an amount of fossil fuel with electrolytically-produced hydrogen which creates no CO_2 emissions. In the short term scenario, the value of SCC saved is nearly 39% and in the long term scenario, this rose to 83%.

1. Introduction

1.1. Social Carbon Cost (SCC) estimation methods

The Social Carbon Cost (SCC) is an estimate of the monetised damages caused by a one-ton increase in greenhouse gas (GHG) emissions in a given year. The monetisation of CO_2 impact is important for determining suitable climate policies. Carbon pricing based on the social cost provides the appropriate economic incentive for decreasing the level of current CO_2 emissions (Nordhaus, 2017). The main tools for calculation of the SCC are called Integrated Assessment Models (IAMs). IAMs include a method for putting into a framework of economic growth the anticipated climate impacts of CO_2 emissions (Krey et al., 2019).

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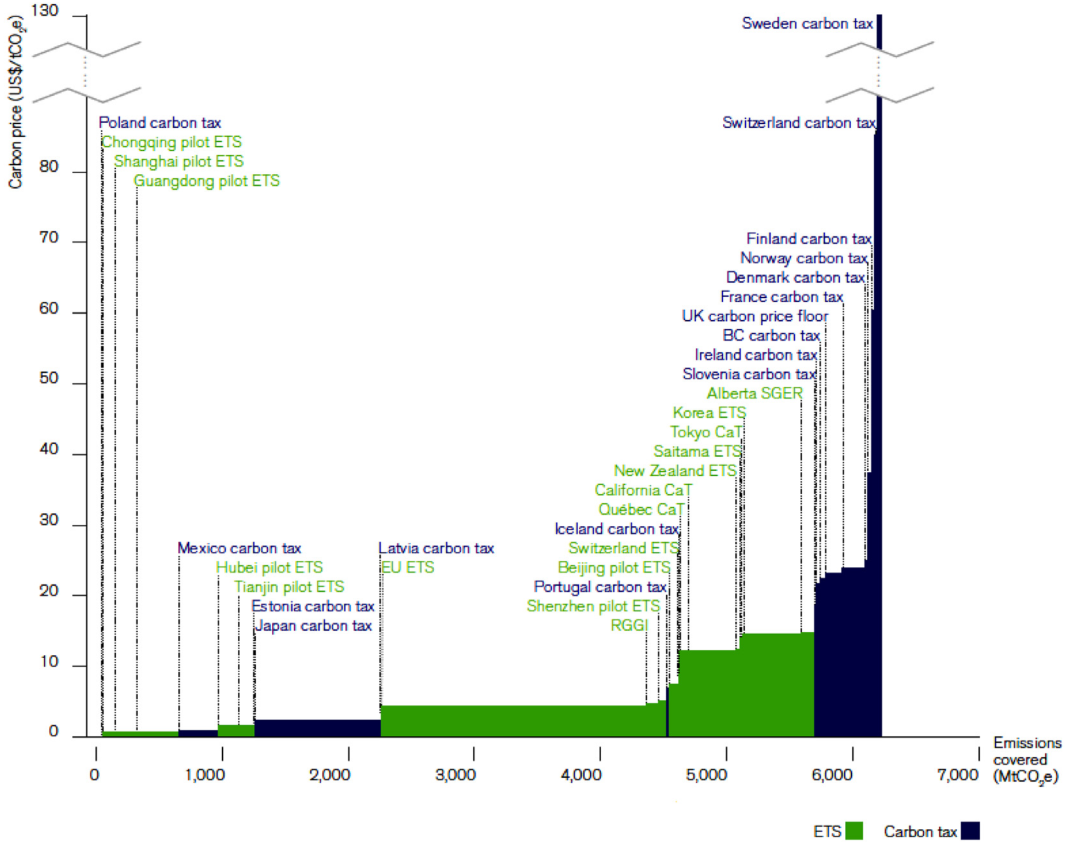

Fig. 1. Prices under emissions trading systems and carbon taxes in 2016 (Richard et al., 2016) . (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

The SCC is calculated approximately as the difference between current and future Gross Domestic Product (GDP) as affected by damage resulting from CO_2 emissions, discounted back to the current time (Havranek et al., 2015).

There are three common models, which are (1) Dynamic Integrated Climate and Economy (DICE) developed by Nordhaus (2018), (2) Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) developed by Tol (2002) and (3) Policy Analysis of the Greenhouse Effect (PAGE) developed by Hope (2008). Through different techniques, each model determines how climate effects result in economic damage. Currently, there are a few IAMs that are available for assessing the causes and impacts of climate change and could therefore be used to estimate an internally-consistent SCC (Lamperti et al., 2019).

The DICE model is one of the main IAMs applied by governments and scholars for calculating the SCC (National Academies of Sciences and Medicine, 2016; Nordhaus, 2017). The efficacy of the IAM approach has been assessed in many studies (Hope, 2008; Nordhaus, 2014) and these reveal that a higher sensitivity to climate, a higher estimation of damage from a given temperature change and a lower value discount rate would lead to a higher estimated SCC (Nordhaus, 2018).

IAMs have been used to derive an analytical formula for the SCC, based on particular assumptions such as the utility logarithm and the exponential relationship between atmospheric CO_2 and damage arising from climate change.

1.2. Present and future values of SCC

The quantity of CO_2 released varies between countries depending on their economic growth and the types of energy used to power their economies. Generally, the price of CO_2 emissions has be set at a low level to date (Adam Whitmore, 2017). Fig. 1 shows carbon prices against carbon tax levels (purple) and emission trading schemes (green) for different countries across the world (Pindyck, 2019).

As presented in Fig. 1 above, the price of the EU Emissions Trading System (EUETS) is about \$5–6/ton while the Chinese price much the same, if not lower, and the California price somewhat higher. France's carbon tax of is planned to be set at €56/t CO_2 (US\$62/t CO2) by 2020 and €100/t CO_2 (US\$111/t CO_2) in 2030, which falls outside the EUETS goals. Canada's target is to reach US\$50/t CO_2 by 2022. The Department for Business, Energy and Industrial Strategy (BEIS) in the UK updated its short-term traded carbon values in March 2016, and prices of carbon per ton (£/t CO_2e) are presented over three different scenarios. These scenarios are low, central and high, as given in Table 1 (Ricke et al., 2018).

The dollar figure can be defined as 'the avoided damage due to the CO_2 reduction'. Table 2 shows the technical update of SCC in August 2016 in the US under different values of discount rate (Hope, 2008).

1.3. Overview of SCC of Middle East and North African countries

The Middle East and North African (MENA) is one of the highest CO_2-emitting regions of the world due to the dominant role of its oil and gas industry (Al-mulali, 2011) plus the rise in modern lifestyles of its people. By the year 2000, the MENA region had developed to the point of having the largest carbon footprint per capita in the world. For example, in 2013 the carbon footprint per capita in the UAE was 18.8 tonnes whereas 7.1 tonnes was the share per capita in the United Kingdom (Data, 2017). Fig. 2 shows

Table 1
BEIS updated of short-term traded sector carbon values in real 2016, £/tCO2e.

Year	Low	Central	High
2016	0.00	4.18	4.18
2017	0.00	4.22	4.22
2018	0.00	4.25	4.61
2019	0.00	4.41	7.22
2020	0.00	4.58	9.14
2021	3.87	11.86	19.83
2022	7.74	19.14	30.52
2023	11.61	26.42	41.21
2024	15.47	33.70	51.90
2025	19.34	40.98	62.60
2026	23.21	48.25	73.29
2027	27.08	55.53	83.98
2028	30.95	62.81	94.67
2029	34.82	70.09	105.36
2030	38.68	77.37	116.05

Table 2
SCC per metric ton CO_2 between 2015 and 2050 (in 2007 US dollars).

Year	Discount rate and statistic			
	5% average	3% average	2.5% average	High impact (95th pct at 3%)
2015	$11	$36	$56	$105
2020	$12	$42	$62	$123
2025	$14	$46	$68	$138
2030	$16	$50	$73	$152
2035	$18	$55	$78	$168
2040	$21	$60	$84	$183
2045	$23	$64	$89	$197
2050	$26	$69	$95	$212

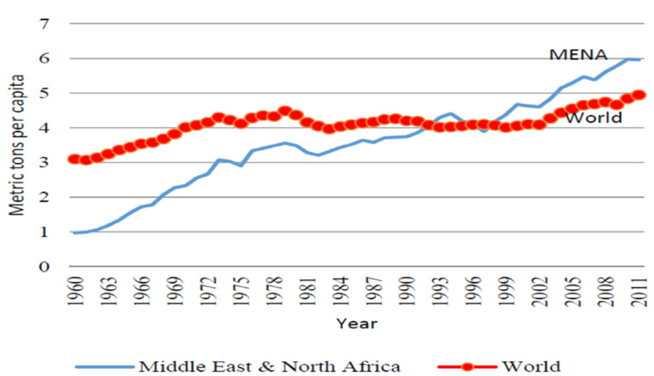

Fig. 2. Metric tons of CO_2 in MENA and world between 1960 and 2011 (Magazzino, 2016).

the metric tonnes of CO_2 per capita of MENA and other parts of the world.

Due to the fast growth of the O&G industry, some MENA countries have considered introducing policies to reduce the CO_2 emissions, one of which might be the creation of a carbon trading mechanism to incentivise countries to reduce GHG emissions. The carbon market could be linked with the deployment of renewable energy (RE) generation and the development of the RE industry in the MENA region, which faces multiple challenges (El-Katiri, 2014; Hadjipanayi et al., 2016) such as:

1- Lack of RE institutions and an absence of coordination between them
2- Political instability, which may deter investment an RE industry in the region
3- Insufficient financial incentives
4- Technological obstacles such as grid weakness
5- A low level of awareness among both customers and decision-makers about the potential economic benefits of an indigenous RE industry

2. Carbon dioxide (CO_2) emissions and their impact in Libya

Libya has a small population of nearly 6.5 million (as of 2010) and does not have a heavy agricultural potential or a wide industrial base like its neighboring countries such as Algeria, Morocco, Tunisia and Egypt. On the other hand, Libya has abundant energy resources with large reserves of oil and gas. For instance, Libya leads the African countries in terms of proven reserves of crude oil (Rahil et al., 2018a). In terms of natural gas, Libya has proven reserves were measured at 55 trillion cubic feet in 2014, which is one of the highest reserves in Africa. Nearly 70% of Libyan Gross Domestic Product (GDP) comes from the oil-exporting sector, having increased from nearly 50% in 2002 in line with the increasing price of oil (Rahil et al., 2018b). Libya relies completely on fossil fuel to produce its energy. Natural gas and oil are the main sources of energy. Libyan power plants currently rely on oil, though there has been an increasing move towards natural gas power plants over recent years (Rahil, 2018).

The current global trend towards reducing GHG emissions, both in terms of current and future energy generation (Le Quéré et al., 2009; The Paris Agreement *vert* UNFCCC, 2018), is based on strong scientific assertions about the effects of a rapidly changing climate that will put considerable strain on environmental, social and economic sustainability. Experts currently warn of the risk of worldwide climate change in due to human-induced GHG emissions, mainly from the use of fossil fuels. The United Nations Framework Convention on Climate Change (UNFCCC) adopted the Kyoto Protocol in 1997, which was signed by 84 states, under which major industrialised countries must limit their greenhouse emissions to 1990 levels or lower (CDM, 2009). The Human Development Report (HDR) 2007/2008 indicates that the annual increase in CO_2 emissions was around 4.2% between 1999 and 2004. Furthermore, the same report indicated that Libya was responsible for 0.2% of international carbon emissions, which equates to around 9.3 tons of CO_2 per person. In terms of various international environmental conventions, Libya has signed and ratified numerous agreements such as the Vienna Convention in 1990, the United Nations Framework Convention on Climate Change in 1999 and the Kyoto Protocol in 2006 as a Non-Annex I party. Therefore, Libya has the opportunity to implement carbon emissions reduction policies such as an emissions trading mechanism. Well-defined emission-reduction policies and environmental regulations are key to mitigating the challenge of climate change. Libya is the world's 11th largest oil producer (Pratten and Abdulhamid Mashat, 2009) and, as a consequence of rising petroleum production and the associated revenues (accounting for about 95% of export earnings and contributing more than 54% of its GDP), Libya has seen a significant increase in GHG emissions, particularly CO_2, Elhage et al. (2005). Oil and cement manufacturing are the major contributors to GHG emissions in Libya, which like most other countries that have seen significant increase in their greenhouse emissions, can be related to both economic and industrial growth. High levels of urbanisation also contribute in this regard in the larger urban centers in Northern Africa. However, Libya has seen the highest per-capita increase in CO_2 emissions by comparison to neighboring countries, including CO_2 produced from the consumption of solid, liquid, and gaseous fuels and gas flaring (Khalil et al., 2009). The main sources of air pollution in Libya are related to the use of petroleum derivatives as fuels in many manufacturing, industrial and transport field. CO_2 mostly originates from the burning of various fuels by the power production sector (38%), the transport sector (20%) and industry (8%), with other sectors representing the remaining 34% (Mohamed R.Zaroug, 2012; Lawgali, 2008). Various harmful or hazardous gases are released from oil fields and refineries (primarily, carbons, hydrocarbons, sulfur and nitrogen oxides), and

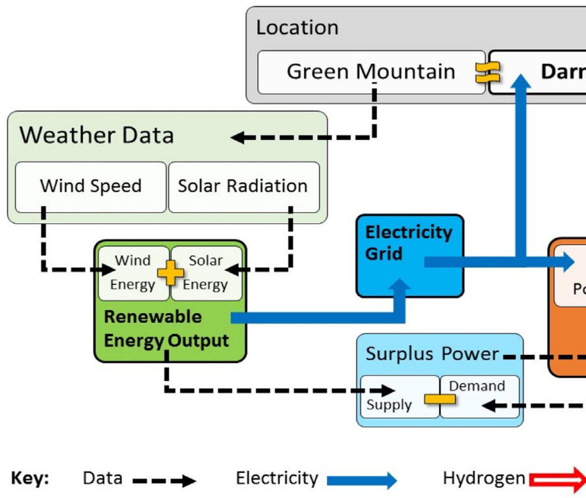

Fig. 3. General overview of renewable energy and hydrogen production and consumption process.

these adversely affect the surrounding residential and maritime areas. In 2003, petroleum was responsible for more than 60% of Libya's CO_2 emissions, with natural gas accounting for the remaining 40% (Madziga et al., 2018; Mohamed R.Zaroug, 2012). In 2010, two thirds of electricity in the world was produced from burning fossil fuels and, in the same year, Libya produced about 60 million tons (Mt) of CO_2, compared with 50 million tons (Mt) in 2002. Libya's energy-related CO_2 emissions rose by more than 78%, from less than 18.7 million tons of oil equivalent (Mtoe) in 1980 to about 50 Mtoe in 2003. This was mainly because of increasing demand for power (Ekhlat et al., 2007). The amount of emissions per unit energy varies depending on the fuel type (i.e., coal, oil or natural gas) and therefore, the move towards the increased use of natural gas should ultimately help to significantly lower CO_2 emissions (Mohamed et al., 2015). Because of increasing energy demand, CO_2 emissions are expected to more than double in coming years, reaching around 104 Mt in 2030 (Rahil and Gammon, 2017). The annual average growth in emissions is determined to be 3.3% over the outlook period. However, this is lower than the original forecast (3.6% growth in demand) due to the move towards gas-fired power stations. The daily data recorded for CO_2 emissions includes fuel intake and energy production from various generators, particularly combined cycle units, which account for about 37% of the total electricity produced in the Libyan network (Khalil et al., 2009).

3. Methodology

3.1. Data collection

The collection of data in this paper include the electricity demand data, fuel consumption data and weather data. Weather data (wind and solar) were collected from commercial websites, NASA and as well as airports. Electricity demand was extracted from general electricity company of Libya in daily pattern and this is the reason for using daily calculation for the work (GECOL, 2010). Some history background about renewable energy projects and the future planned project information is taken from renewable energy authority in Libya (Mohamed R.Zaroug, 2012). Finally, fuel consumption data is extracted from daily record of stations consumption since our work focus in small city. Regarding oil prices and government subsides, bank loans, interest: they are extracted from Libyan central bank and national oil corporation (Rahil et al., 2018b).

3.2. Research technique and tools

Matlab software has been used to formulate all parts of the paper model but with different tools. Matlab code has been designed to analysis the weather data. Some Matlab tools was used such as probability distribution, Weibull parameters with many different commands. Then the system sizing model was created to extract the surplus power after comparing the demand and supply. This process requires various calculations; for example, the wind speed had to be converted into a daily pattern, then a suitable wind turbine based on the wind speed data had to be selected, and finally the capacity factor had to be computed to determine how many turbines would need to be installed to meet the demand. The last process, the sizing system, mainly depends on the PV system sizing, the wind turbine sizing and average demand. Due to the absence, to date, of an extensive hydrogen market, the hydrogen demand calculation cannot be computed with any great degree of accuracy. The widespread uptake of hydrogen markets will rely initially on the availability of a hydrogen-based infrastructure, particularly a hydrogen station infrastructure and hydrogen-fueled cars. The data for petrol stations is not available from any official source; only annual fuel consumption can be extracted from the National Oil Corporation or Central Bank of Libya. However, after the introduction of the new system, which would the manager or owner the power to control their own station, unofficial daily reports would be performed to determine costs and revenues, as well as any shortage of oil components. As a result, fuel consumption data were obtained from the station owners' daily records. The main objective of this paper is encouraging the oil rich countries to reduce the CO2 emissions via economic factor. In other words connecting the reduction of the CO2 emissions with SCC. More information can be founded in the following references Rahil et al. (2018a,c).

4. Renewable energy integration scenario for Libya

In this paper, the RE resource is based on wind data for Darnah city since some wind power projects are already installed in that area. Darnah is a small city in the eastern coastal region of Libya (32°46′N, 22°38′ E) (Tvinnereim, 2014). This case-study location sees favorable wind speeds of 8.0–8.5 m/s based on the data taken from the Renewable Energy Authority of Libya (REAOL) (Mohamed R.Zaroug, 2012). Wind speed and solar irradiance levels at Green Mountain, which is relatively nearby, are used

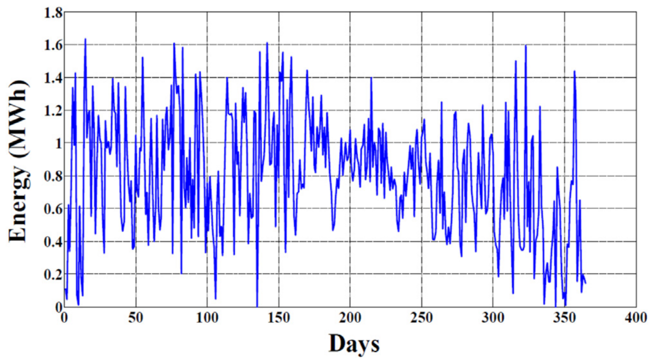

Fig. 4. Daily energy production for one turbine throughout the year.

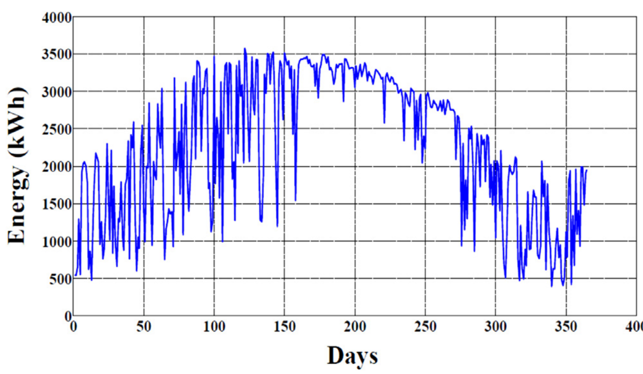

Fig. 5. Daily AC energy produced from 14 MW PV energy system.

as data for this paper, but energy and fuel consumption data are those applicable to Darnah city. Since temporary RE power surpluses would be converted into hydrogen that can be used instead of fossil fuels, consumption levels will be estimated on the basis of fossil fuel demand in Darnah. This process is more easily demonstrated in Fig. 3.

The wind turbine output power can be calculated using the formula below:

$$P(t) = \begin{Bmatrix} P_{rated} \times \dfrac{V(t) - Vin}{Vr - Vin} & Vin \le V(t) \le Vout \\ P_{rated} & Vr \le V(t) \le Vout \\ 0 & V(t) < Vin \cup V(t) > Vout \end{Bmatrix} \tag{1}$$

The total energy produced from a 14 MW PV system can be computed using the formula below.

$$E = A \times r \times H \times Pr \tag{2}$$

where E is the total energy produced (kWh), A is total solar panel area (m^2), r is solar panel yield (%), Pr is the performance ratio and H is daily solar irradiation (kWh/m^2 day). Fig. 4 show the energy produced from one turbine over one year in hourly patterns. The hourly solar radiation for Darnah can be obtained from the national renewable energy Laboratory data and the NASA website (NREL, 2013). Fig. 5 shows the solar radiation in Darnah over a year.

Most of the available commercial or academic sizing software has two main problems: the input requirement is very large and substantial computational resources are required to dimension a system size (Rahil et al., 2018c). In this paper, a simple tool that leads to sizing on-grid hybrid systems is proposed. This model will work only in the case of surplus power. In other words, any shortfall from renewables will be supplemented by fossil fueled generators or the grid, but these are out of the scope of this

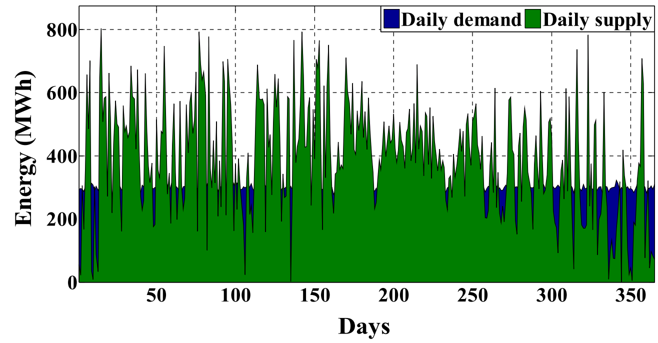

Fig. 6. Green mountain daily demand in contrast with energy production after sizing process.

work. Therefore, this model will focus on supplying the case-study area from renewable energy sources (wind and PV) and any surplus will be available for electrolysers to produce hydrogen. The input for this system is the wind power data, PV system data and the demand data. This model been developed using MATLAB software.

The sizing process flow can be summarised as per the points below:

1- Sizing the PV system: since the 14 MW system is assumed to be installed with a capacity factor of 16%, there is no further need to do any further calculations for this system because the PV system is fixed and daily energy can be calculated as per Eq. (2)

2- Sizing the wind turbine: the characteristics of the wind turbine used in this paper were based on real-world data from the Darnah project to make this work as close as possible to genuine data calculations. The next step is to estimate the needed power in the Green Mountain area. Average demand will be as calculated in Eq. (3):

$$P_W = \frac{\overline{P_{dem}} - CF_{PV} \times P_{pv}}{CF_W} \tag{3}$$

where P_W is wind power, $\overline{P_{dem}}$ is average demand, CF_{PV} is the solar system capacity factor, P_{pv} is the solar system rated power and CF_W is the wind turbine capacity factor. The previous step will give the total energy required to satisfy the demand from renewable energy based on the weather situation. In other words, some days this system will be unable to meet demand, with the deficit then being supplied by non-renewable sources. By dividing the required amount of power by the rated power of each wind turbine, the number of turbines required will be known, as per Eq. (4):

$$N_W = P_W / r_P \tag{4}$$

where r_P is the rated power of the chosen turbine (1.65 MW). Based on the calculations in Eqs. (3) and (4), the total energy required from the wind system is 808.1677 MWh, and the number of wind turbines required to produce this amount of power is ≈ 490. Fig. 6 shows the daily pattern of total energy produced from the system compared to energy demand and Fig. 7 presents the daily surpluses of energy generated (from REs) in MWh.

5. Estimation of hydrogen demand in Darnah

There are assumed to be six Hydrogen Refueling Stations (HRSs) across the city with heavy daily fuel consumption, estimated on average at 6787.247 liters/day, 9681.243 liters/day,

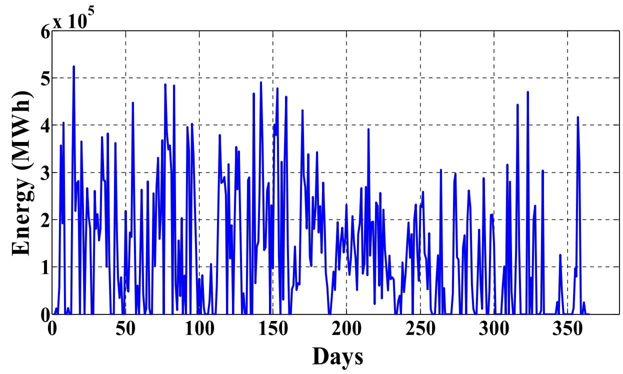

Fig. 7. Daily surplus energy after the comparison between demand and supply.

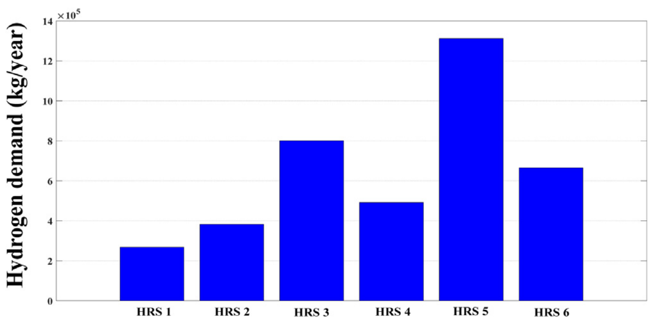

Fig. 8. Hydrogen consumption per HRS (kg/year).

20 263.316 liters/day, 12 429.996 liters/day, 33 216.344 liters/day, and 16 827.954 liters/day for HRSs 1 to 6, respectively. Because of the absence to date of an extensive hydrogen market, the hydrogen demand calculation cannot be computed with a great accuracy. Estimations of hydrogen consumption are therefore based on current fossil fuel consumption (Dagdougui et al., 2012; Greiner et al., 2007). Lower and higher heating values and the conversion efficiencies of hydrogen and fossil fuel engines were used to calculate associated hydrogen consumption, as per Eq. (5).

$$Q_{H_2} = Q_{ff} \times LHV_{ff} \times \mu_{ff} / LHV_{H_2} \times \mu_{H_2} \tag{5}$$

where Q_{H_2} is the hydrogen demand (kg), Q_{ff} is the estimated fossil fuel demand (kg) at a conventional garage forecourt, LHV_{ff} is fossil fuel's lower heating value (43.448 MJ/kg ≈ 12.06 kWh/kg), μ_{ff} is the efficiency of a fossil-fueled engine (20%), LHV_{H2} is the lower heating value of hydrogen (120.21 MJ/kg ≈ 33.33 kWh/kg), and μ_{H2} is the efficiency of the hydrogen engine (40%–60%). Fig. 8 shows the total yearly demand for HRSs 1 to 6.

Only 20% of estimated fuel demand will be met by hydrogen, as the amount that can be produced from surplus energy in this scenario (6% RE penetration) is not sufficient to meet the total demand. The RE system sizing, surplus energy extraction and hydrogen demand estimation were previously discussed in details by the authors (Rahil et al., 2018a, 2017; Rahil and Gammon, 2017).

6. Flexible hydrogen production based on surplus energy availability

Different scenarios have been investigated in order to examine how the following objectives might be satisfied:

1- The majority of temporary power surpluses must be consumed (at least 90%) to support grid balancing and thus increase the potential for penetration of RE resources into the Libyan grid.
2- As far as possible, hydrogen demand at the forecourt must be met without interruption.
3- The hydrogen sale price (which depends upon production cost) should be competitive with that of fossil fuels.

In this paper, a range of system configurations are assessed under two different cost assumption scenarios: one being a 2015-Cost scenario and the other a 2030-Cost scenario. In all cases, the electrolysers are assumed to be of the alkaline type, located onsite at the HRSs and, in certain cases, there is also a central offsite electrolyser in addition to these. This gives rise to a range of scenarios, as set out in Tables 3 and 4:

More details about the hydrogen production scenarios can be found in Appendix A.

The storage tank is one of the most expensive components of the HRS systems. Since all scenarios are running only during off-peak times, the storage should be designed based on times of hydrogen shortage without surplus power in order to absorb as much power as possible, and thus allow for the sale of hydrogen at times of power shortage. The storage size is taken as four times the capacity of each electrolyser, because there are frequently four consecutive days without any surplus power during the year. As well as equipment sizes, the electricity trading mechanism is key to the success of the whole system, hence the scenarios also compare the effect of the allowing central electrolyser to purchase power at a preferential tariff in contrast with it paying the same settlement price as the HRSs.

7. Potential economic benefits of previous scenarios through CO_2 reduction

Regardless of the environmental benefits that can be achieved when RE sources are integrated into energy systems or hydrogen is used as a replacement for fossil fuel, the economic performance is critical to any project. So, given the importance of achieving commercial viability, the economic benefits of deploying of RE will be assessed.

Economic benefits can be determined in different ways depending on the intention of the government and how the benefits are monetised. In other words, if the target is to reduce CO_2 emissions, some fossil fuel production must be cut and replaced by RE sources and hydrogen. There are also 'external costs' arising from the use of fossil fuels, which include the cost of dealing with negative environmental and health effects. The use of CO_2 taxes is a way of internalising external cost.

The economic benefits of this scenario can be obtained by the introduction of the CO_2-based taxes. Another option is to maintain oil production at the same rate as before RE deployment so that, rather than being used for local consumption (which can now be partly served by RE), it can be used to increase oil export levels, which in turn will lead to an increase in income, but with the same levels of CO_2 emission. The scenarios in this study are used to assess the potential environmental and economic benefits under two fossil fuel production regimes. In the first (Section 7.1), the introduction of RE into the electricity system allows a reduction in fossil fuel consumption and so production is curtailed accordingly with the intention of lowering the country's overall GHG emissions. In the second case (Section 7.2), RE still displaces much of the fuel use in the local electricity system, but instead of cutting back fossil fuel production accordingly, it is kept at the same level so that there is more available for export. In this way, net CO_2 emissions remain the same (albeit exported to the countries that purchase the oil or gas), but income from exports increases.

Table 3
The summary of the alkaline electrolyser scenarios under 2015-Cost scenarios.

Details		Scenario No.												
		1	2	3	4	5	6	7	8	9	10	11	12	13
HRSs electrolyser size (kg/day)	HRS 1	149	297	446	446	446	149	149	149	149	149	149	149	149
	HRS 2	226	451	677	677	677	226	226	226	226	226	226	226	226
	HRS 3	449	897	1346	1346	1346	449	449	449	449	449	449	449	449
	HRS 4	282	564	846	846	846	282	282	282	282	282	282	282	282
	HRS 5	744	1487	2231	2231	2231	744	744	744	744	744	744	744	744
	HRS 6	372	744	1115	1115	1115	372	372	372	372	372	372	372	372
HRSs storage size (kg)	HRS 1	560	560	840	1120	1680	560	560	560	560	560	560	560	560
	HRS 2	630	630	945	1260	1890	630	630	630	630	630	630	630	630
	HRS 3	1890	1890	2835	3780	5670	1890	1890	1890	1890	1890	1890	1890	1890
	HRS 4	1190	1190	1785	2380	3570	1190	1190	1190	1190	1190	1190	1190	1190
	HRS 5	2464	2464	3696	4928	7392	2464	2464	2464	2464	2464	2464	2464	2464
	HRS 6	1540	1540	2310	3080	4620	1540	1540	1540	1540	1540	1540	1540	1540
HRSs compressor size (kg/day)	HRS 1	149	297	446	446	446	149	149	149	149	149	149	149	149
	HRS 2	226	451	677	677	677	226	226	226	226	226	226	226	226
	HRS 3	449	897	1346	1346	1346	449	449	449	449	449	449	449	449
	HRS 4	282	564	846	846	846	282	282	282	282	282	282	282	282
	HRS 5	744	1487	2231	2231	2231	744	744	744	744	744	744	744	744
	HRS 6	372	744	1115	1115	1115	372	372	372	372	372	372	372	372
Central electrolyser size (kg/day)		–	–	–	–	–	1098	1923	3021	4853	1098	1923	3021	4853
Central electrolyser storage size (kg)		–	–	–	–	–	5000	9000	15 000	24 000	5000	9000	15 000	24 000
Central electrolyser compressor size (kg/day)		–	–	–	–	–	1098	1923	3021	4853	1098	1923	3021	4853
Electrolyser efficiency (kWh/kg)		54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6
Settlement price compared to HRS		–	–	–	–	–	Different				Same			
Year of the components cost		2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015

Table 4
The summary of the alkaline electrolyser scenarios under 2030-Cost scenarios.

Details		Scenario no.												
		14	15	16	17	18	19	20	21	22	23	24	25	26
HRSs electrolyser size (kg/day)	HRS 1	162	324	486	486	486	162	162	162	162	162	162	162	162
	HRS 2	246	492	738	738	738	246	246	246	246	246	246	246	246
	HRS 3	490	980	1470	1470	1470	490	490	490	490	490	490	490	490
	HRS 4	308	616	924	924	924	308	308	308	308	308	308	308	308
	HRS 5	812	1624	2436	2436	2436	812	812	812	812	812	812	812	812
	HRS 6	406	812	1218	1218	1218	406	406	406	406	406	406	406	406
HRSs storage size (kg)	HRS 1	560	560	840	1120	1680	560	560	560	560	560	560	560	560
	HRS 2	630	630	945	1260	1890	630	630	630	630	630	630	630	630
	HRS 3	1890	1890	2835	3780	5670	1890	1890	1 890	1 890	1890	1890	1 890	1 890
	HRS 4	1190	1190	1785	2380	3570	1190	1190	1 190	1 190	1190	1190	1 190	1 190
	HRS 5	2464	2464	3696	4928	7392	2464	2464	2 464	2 464	2464	2464	2 464	2 464
	HRS 6	1540	1540	2310	3080	4620	1540	1540	1 540	1 540	1540	1540	1 540	1 540
HRSs compressor size (kg/day)	HRS 1	162	324	486	486	486	162	162	162	162	162	162	162	162
	HRS 2	246	492	738	738	738	246	246	246	246	246	246	246	246
	HRS 3	490	980	1470	1470	1470	490	490	490	490	490	490	490	490
	HRS 4	308	616	924	924	924	308	308	308	308	308	308	308	308
	HRS 5	812	1624	2436	2436	2436	812	812	812	812	812	812	812	812
	HRS 6	406	812	1218	1218	1218	406	406	406	406	406	406	406	406
Central electrolyser size (kg/day)		–	–	–	–	–	1098	1923	3 021	4 853	1098	1923	3 021	4 853
Central electrolyser storage size (kg)		–	–	–	–	–	5000	9000	15 000	24 000	5000	9000	15 000	24 000
Central electrolyser compressor size (kg/day)		–	–	–	–	–	1098	1923	3 021	4 853	1098	1923	3 021	4 853
Electrolyser efficiency (kWh/kg)		50	50	50	50	50	50	50	50	50	50	50	50	50
Settlement price compared to HRS		–	–	–	–	–	Different				Same			
Year of the components cost		2030	2030	2030	2030	2030	2030	2030	2 030	2 030	2030	2030	2 030	2 030

7.1. CO_2 emission reduction and associated benefits (reduction in fossil use due to renewable energy integration into the grid)

In this case, there are two components that need to be calculated, namely those of the energy injected to the grid and used to meet demand, and the surplus energy that is exploited to produce hydrogen. The calculation will be based on the fossil fuel reduction when the hydrogen is used as a substitute. Fig. 9 explains the CO_2 reduction process.

The cost of any CO_2 produced differs between countries. In the UK, this cost will increase to £116.05/t CO_2e by 2030 (GOV.UK, 2016). It is straightforward to calculate the total energy consumed since the RE generation and energy surpluses are known

$$\textit{Total consumed energy} = \textit{total RE production} - \textit{total surplus energy} \tag{6}$$

$$\textit{Total consumed energy} = 143{,}481 - 47{,}488 = 95{,}993 \text{ MWh}$$

Based on the General Electricity Company Of Libya (GECOL), the Libyan emission factor is 0.8843t CO_2/MWh in 2012

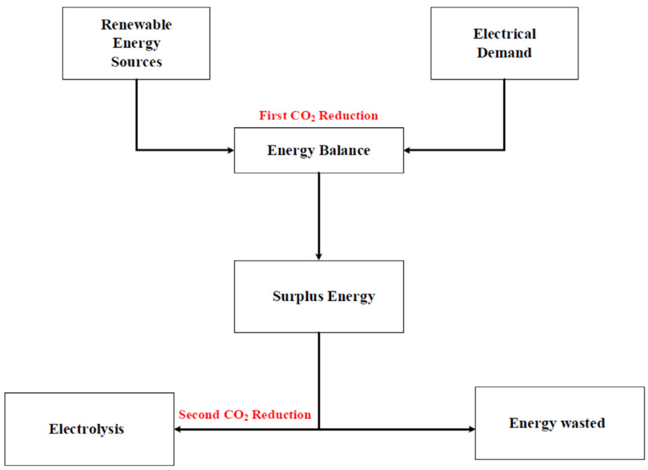

Fig. 9. Summary of CO2 reduction process.

(CDM, 2009). So, the total CO_2 emissions from energy sources that will be replaced by RE can be calculated by Eq. (7).

$$\textit{Total } CO_2 \textit{ emissions } = \textit{total consumed energy} \times CO_2 \text{ emission factor} \tag{7}$$

$$\textit{Total } CO_2 \textit{ emissions} = 95{,}993 \times 0.8843 = 84{,}887 \text{ t } CO_2\text{e}$$

The social cost of carbon (SCC) in Libya seems to be ambiguous and difficult to estimate and so assumptions are applied for 2015 and 2030 prices based on prices in the UK (Litterman, 2013). In this paper, the current SCC is small at nearly \$10/t CO_2 (£7.76/t CO_2 in 2015, while a future price of between \$100 and \$200 is assumed at \$150/t CO_2 (£116.42/t CO_2) in 2030, as based on 2017 exchange rates (Litterman, 2013).

Assuming these prices, the monetary savings that can be achieved through using RE in the electricity sector can be computed as follows:

$$\textit{Current total saving money} = \textit{Total } CO_2 \textit{ emissions} \times SCC_{current} \tag{8}$$

$$\textit{Current total saving money} = 84{,}887 \times 7.76 = £658{,}723$$

$$\textit{Future total saving money} = \textit{Total } CO_2 \textit{ emissions} \times SCC_{future} \tag{9}$$

$$\textit{Future total saving money} = 84{,}887 \times 116.42 = £9{,}882{,}545$$

The future monetary saving is promising, and could well encourage many companies and states to reduce their emissions, in contrast with the low savings that are currently possible. The cost reduction due to the use of hydrogen as a fuel instead of fossil fuels will be calculated in all scenarios under the 2015- and 2030-Cost assumption scenarios above. Due to difficulties in determining Libya's CO_2 emissions, the latest available information from the UK will be applied (GOV.UK, 2016).

Based on this information, burning 1 ton of fossil fuel (mainly diesel) will produce around 3108.5 $kgCO_{2e}$. Meeting hydrogen demand in each scenario represents an equivalent fossil fuel reduction, and thus, the cost can be calculated for the current and future SCC. The calculation steps are presented in Fig. 10.

The total savings for the system under the 2015- and 2030-Cost assumption scenarios can be calculated by Eq. (10)

$$\textit{Total monetary savings} = \textit{total money saved from energy} + \textit{total money saved from fuel} \tag{10}$$

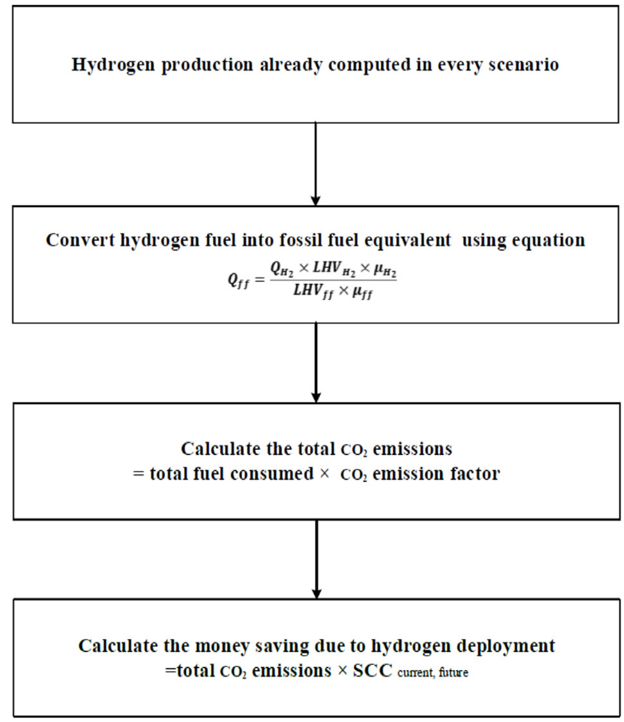

Fig. 10. Process of saving money due to hydrogen energy deployment.

7.2. Export crude oil instead of curtailing production

The total energy consumed via the electricity sector and the production of hydrogen fuel is equal to the energy that could be exported as a fuel. Two cost scenarios 2015 and 2030 are investigated in this paper. The current fuel prices are 69.69 LD/barrel (£34.85/barrel) of oil and, for barrel of oil equivalent (boe) of natural gas, the price was 21.17 LD (£11.61) in 2015 (Bloomberg, 2017). In Libya, the power sector is fueled by a combination of oil and natural gas resources. Based on the renewable GECOL reports in 2012, the total fuel consumption by the electricity sector was 10,197 thousand tonnes of oil equivalent (toe). Of this, 65% is supplied by natural gas, 23% from light fuel oil and 12% from heavy fuel oil (GECOL, 2010).

Fuel savings made by substitution with RE in the electricity network would enable an equivalent amount of energy to be exported that – based on the fuel consumption figures for Libya's energy sector – would consist of 65% natural gas (NG) and 35% oil. Emissions arising from the extraction process of natural gas and oil should be calculated and subtracted from the revenue generated by sales of fuel. The general formula to calculate the profit resulting from RE deployment, plus the sale of fuel, is given below.

$$Revenue = F.S + E.r_{CO2} + F.r_{CO2} - E.c_{CO2} \tag{11}$$

where $F.S$ is from sales of fuel, $E.r_{CO2}$ is the monetary saving due to CO_2 reductions resulting from RE generation, $F.r_{CO2}$ is the monetary saving due to CO_2 reductions in fuel use and $E.c_{CO2}$ are costs due to CO_2 emissions from oil and natural gas extraction. The world average of CO_2 emission intensity for oil and gas extraction is 130 kg CO2/toe (Gavenas et al., 2015). Eq. (12) shows the calculation of revenue form fuel sales.

$$\text{F.S} = \text{NG\_export} \times \text{NG\_price} + \text{Oil\_export} \times \text{Oil\_price} \tag{12}$$

NG_export and Oil_export are the exported amount of natural gas and oil wheres NG_price and Oil_price are the natural gas and oil price. $E.r_{CO2}$ and $F.r_{CO2}$ are calculated where, in the previous case, oil production is curtailed in response to RE generation, whereas $E.c_{CO2}$ can be calculated via Eq. (13).

$$E.c_{CO2} = CO_2\_emissions \times SCC \tag{13}$$

This scenario is clearly better than the previous scenario from an economic perspective because more money will be earned from selling the oil and natural gas. The effect of the carbon tax credit is very low due to SCC having low values. Recent studies and reports (EIA, 2019; Lee and Huh, 2017) suggest that future oil prices will be higher than current prices. They are anticipated to fluctuate between \$111 and \$131/Bbl, where oil is assumed to be \$121/Bbl ≈ £93.65/Bbl, whereas the future price for natural gas is likely to be lower at between \$5 and \$6/million Btu ≈ £4.266/million Btu (EIA, 2019).

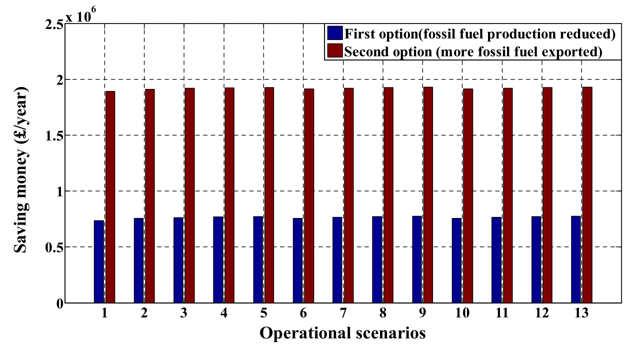

Fig. 11. Comparison of two options for adjusting the oil market in response to renewable energy penetration in terms of CO_2 reduction using 2015-Cost assumptions.

8. Results and discussion

Various scenarios for hydrogen production have been investigated. The first explored the use of an electrolyser at each HRS, where the amount of surplus energy absorbed, the level of satisfaction of hydrogen demand and the average hydrogen price were investigated.

Then the electrolysers and hydrogen storage capacities were increased to address the weaknesses of this first scenario. Next, a very large central electrolyser was added to cover the shortfall in absorption of energy surpluses by the HRSs and the shortages in meeting hydrogen demand. Two modes of operation were tested for the central electrolyser in which it either paid the same settlement price for its electricity consumption as the HRSs, or it had its own preferential tariff. The details of these entire scenarios are summarised and presented in the supplementary documents in Appendix A.

A summary of CO_2 reduction and monetary savings due to hydrogen fuel penetration for alkaline operation under the 2015-Cost scenario is presented in Table 5. In this scenario, due to the lower cost of *SCC*, the total savings resulting from fuel and energy reduction does not represent any real incentive to encourage governments to reduce emissions, at least from an economic perspective. However, in the future scenario, the *SCC* will be considerably higher in order to enhance renewable energy penetration.

Table 6 shows the summary of CO_2 reduction and monetary savings due to hydrogen fuel penetration for alkaline operation and under the 2030-Cost scenario. A summary of the total monetary savings for alkaline electrolyser operation under the 2015- and 2030-Cost scenarios due to replacing conventional sources of electricity and fuel by renewable energy sources are presented in Tables 7 and 8, respectively.

Generally, each iteration of the scenario represents an adjustment that aims to tackle the weaknesses of the previous one. For example, the revenue when the system size is doubled £755,981/year, which is higher than the default size (at £736,949/year). This is due to an increase for energy absorbed, which produces more hydrogen and consequently leads to greater CO_2 reduction. The case is the same in the following scenario, as given in Table 3. Average hydrogen prices in the 2015-Cost scenario are relatively expensive, especially when the system size is increased or when a central electrolyser is added to the system. However, the average hydrogen cost is not taken into consideration in this paper, because the work is focussed on the impact of reducing CO_2 based on current and future values of the SCC.

In the future scenarios, all studies and reports anticipate higher values of SCC, as presented in Table 1 for the UK and Table 2 for the United States. The rise of energy consumption in the electricity and fuel sectors is ignored in order to determine the difference between 2015 and 2030 for a given level of energy consumption. Since energy demand is assumed to be the same for all scenarios, the cost of RE consumption for the electricity sector is one value for all 2015-Cost scenarios and another value for all 2030-Cost scenarios. Only when surplus energy extracted and hydrogen production is involved are the costs affected.

The revenue in 2030 is clearly higher than in the 2015-Cost scenarios due to the large difference between the SCC values. For instance, in scenarios with no central electrolyser, the total revenue dramatically increased from £736,949/year in 2015 to £11,160,837/year in 2030. However, the most important comparison is between the current scenario and the one that focusses on exporting oil and natural gas as a main source of income. The second option is to export the extra oil and gas that is made available by the penetration of renewables into the domestic market, instead of reducing production in response to it. This option has a clear economic benefit, as the producer will earn more from the additional fossil fuel exports. This scenario is clearly better than the previous scenario from an economic perspective, but the effect of carbon tax credit is very low due to the SCC having low values. Table 9 shows the 2015-Cost scenarios and Table 10 shows the 2030-Cost scenarios.

Even with the currently low price of oil (≈£34.85/barrel) and natural gas (£11.61/boe), the option of increasing exports is considerably better than the option of reducing production. This is due to the low value of the SCC in 2015 (£7.76/tCO2). The emissions resulting from the additional oil and natural gas production and their export are considered penalties, which have to be paid by the government. Even so, the revenue under all such scenarios is higher than the reduced production option. Fig. 11 compares the two scenarios under the 2015-Cost scenario for all operation modes mentioned in Tables 7 and 9.

As shown in Fig. 11, the difference is considerable, and it would seem difficult to encourage the government to stop producing oil and making money from a reduction in CO_2 penalties instead.

General expectations are that there will higher oil prices in coming years, which are anticipated to reach \$121/Bbl(≈ £93.65/Bbl) (Bloomberg, 2017; Lee and Huh, 2017). The SCC will increase to £116.05/tCO_2e in 2030, according to UK data (GOV.UK, 2016). This predicted increase will lead to greater benefits under both production and export scenarios, with greater financial savings in the second (increased export) scenario. Fig. 12 shows the comparison between these scenarios for all operational modes under the 2030-Cost forecasting for SCC. Other factors could enhance the situation that are not considered in 2030-Cost scenario, such as further rapid reductions in the cost of wind and solar power production (£/kWh) and potential worldwide

Table 5
Summary of CO_2 reduction and monetary savings due to substituting hydrogen for fossil fuel use in Darnah using the 2015-Cost assumptions..

2015-Cost scenario						
Scenarios			Cost			
			Total hydrogen production (ton/year)	Total fossil fuel reduction (ton/year)	Total CO_2 reduction (tCO_{2e}/year)	Total saving (£/year)
Scenario 1			469	3243	10,081	78,226
Increase the system size	Scenario 2		583	4032	12,533	97,258
	Three times the default electrolyser size	Scenario 3	627	4339	13,487	104,662
		Scenario 4	659	4556	14,162	109,895
		Scenario 5	682	4719	14,668	113,820
Central electrolyser operates under a different electricity settlement price to HRSs		Scenario 6	588	4068	12,644	98,121
		Scenario 7	635	4393	13,656	105,971
		Scenario 8	674	4664	14,499	112,512
		Scenario 9	698	4827	15,005	116,437
Central electrolyser operates under the same electricity settlement price as the HRSs		Scenario 10	588	4068	12,644	98,121
		Scenario 11	635	4393	13,656	105,971
		Scenario 12	674	4664	14,499	112,512
		Scenario 13	698	4827	15,005	116,437

Table 6
Summary of CO_2 reduction and monetary savings due to substituting hydrogen for fossil fuel use in Darnah using the 2030-Cost assumptions..

2030-Cost scenario						
Scenarios			Cost			
			Total hydrogen production (ton/year)	Total fossil fuel reduction (ton/year)	Total CO_2 reduction (tCO_{2e}/year)	Total saving (£/year)
Scenario 14			511	3532	10,980	1,278,292
Increase the system size	Scenario 15		610	4216	13,107	1,525,917
	Three times the default electrolyser size	Scenario 16	651	4502	13,993	1,629,065
		Scenario 17	682	4719	14,668	1,707,649
		Scenario 18	698	4827	15,005	1,746,882
Central electrolyser operates under a different electricity settlement price to HRSs		Scenario 19	612	4230	13,150	1,530,923
		Scenario 20	659	4556	14,162	1,648,740
		Scenario 21	690	4773	14,836	1,727,207
		Scenario 22	714	4935	15,342	1,786,116
Central electrolyser operates under the same electricity settlement price as the HRSs		Scenario 23	612	4230	13,150	1,530,923
		Scenario 24	659	4556	14,162	1,648,740
		Scenario 25	690	4773	14,836	1,727,207
		Scenario 26	714	4935	15,342	1,786,116

Table 7
Summary of total cost reduction due to renewable energy deployment and hydrogen production by electrolysis using 2015-Cost assumptions.

2015-Cost scenario					
Scenarios			Cost		
			Money saved (£/year) (energy reduction)	Money saved (£/year) (fuel reduction)	Total saving (£/year)
Scenario 1			658,723	78,226	736,949
Increase the system size	Scenario 2		658,723	97,258	755,981
	3x default electrolyser size	Scenario 3	658,723	104,662	763,385
		Scenario 4	658,723	109,895	768,618
		Scenario 5	658,723	113,820	772,543
Central electrolyser operates under a different electricity settlement price to HRSs		Scenario 6	658,723	98,121	756,844
		Scenario 7	658,723	105,971	764,694
		Scenario 8	658,723	112,512	771,235
		Scenario 9	658,723	116,437	775,160
Central electrolyser operates under the same electricity settlement price as the HRSs		Scenario 10	658,723	98,121	756,844
		Scenario 11	658,723	105,971	764,694
		Scenario 12	658,723	112,512	771,235
		Scenario 13	658,723	116,437	775,160

agreements to reduce GHG emissions and reduce dependency of fossil fuels. In addition, many oil-rich countries could progress to becoming non-fossil energy suppliers in order to maintain the quality of life for coming generations, since they are well-placed to eventually become RE exporters.

Even with the anticipated high prices of oil and natural gas, the difference achieved for the revenues in each scenario is clearly reduced by high SCC values. For example, looking at 2015-Cost scenarios without a central electrolyser, the case in which fossil fuel production was reduced, the revenue is only 39% of that in

Table 8
Summary of total cost reduction due to renewable energy deployment and hydrogen production by electrolysis using 2030-Cost assumptions.

2030-Cost scenario					
Scenario			Cost		
			Money saved (£/year) (energy reduction)	Money saved (£/year) (fuel reduction)	Total saving (£/year)
Scenario 14			9,882,545	1,278,292	11,160,837
Increase the system size	Scenario 15		9,882,545	1,525,917	11,408,462
	3x default electrolyser size	Scenario 16	9,882,545	1,629,065	11,511,610
		Scenario 17	9,882,545	1,707,649	11,590,194
		Scenario 18	9,882,545	1,746,882	11,629,427
Central electrolyser operates under a different electricity settlement price to HRSs		Scenario 19	9,882,545	1,530,923	11,413,468
		Scenario 20	9,882,545	1,648,740	11,531,285
		Scenario 21	9,882,545	1,727,207	11,6097,52
		Scenario 22	9,882,545	1,786,116	11,668,661
Central electrolyser operates under the same electricity settlement price as the HRSs		Scenario 23	9,882,545	1,530,923	11,413,468
		Scenario 24	9,882,545	1,648,740	11,531,285
		Scenario 25	9,882,545	1,727,207	11,609,752
		Scenario 26	9,882,545	1,786,116	11,668,661

Table 9
Summary of fossil fuel sales using 2015-Cost assumptions.

2015-Cost scenario						
Scenario			Cost			
			Total saving money ($E.r_{CO_2} + F.r_{CO_2}$) (£/year)	Fuel sale ($F.S$) (£/year)	CO_2 emission cost ($E.c_{CO_2}$) (£/year)	Revenue (£/year)
Scenario 1			736,949	1,164,043	8329	1,892,663
Increase the system size	Scenario 2		755,981	1,164,045	8330	1,911,696
	3x default electrolyser size	Scenario 3	763,385	1,164,045	8330	1,919,100
		Scenario 4	768,618	1,164,045	8330	1,924,333
		Scenario 5	772,543	1,164,046	8330	1,928,259
Central electrolyser operates under a different electricity settlement price to HRSs		Scenario 6	756,844	1,164,045	8330	1,912,559
		Scenario 7	764,694	1,164,045	8330	1,920,409
		Scenario 8	771,235	1,164,046	8330	1,926,951
		Scenario 9	775,160	1,164,046	8330	1,930,876
Central electrolyser operates under the same electricity settlement price as the HRSs		Scenario 10	756,844	1,164,045	8330	1,912,559
		Scenario 11	764,694	1,164,045	8330	1,920,409
		Scenario 12	771,235	1,164,046	8330	1,926,951
		Scenario 13	775,160	1,164,046	8330	1,930,876

Table 10
Summary of fossil fuel sales using 2030-Cost assumptions.

2030-Cost scenario						
Scenario			Cost			
			Total saving money ($E.r_{CO_2} + F.r_{CO_2}$) (£/year)	Fuel sale ($F.S$) (£/year)	CO_2 emission cost ($E.c_{CO_2}$) (£/year)	Revenue (£/year)
Scenario 14			11,160,837	2,507,941	124,554	13,544,224
Increase the system size	Scenario 15		11,408,462	2,508,070	124,569	13,791,963
	3x default electrolyser size	Scenario 6	11,511,610	2,508,123	124,569	13,895,164
		Scenario 17	11,590,194	2,508,164	124,569	13,973,789
		Scenario 18	11,629,427	2,508,185	124,569	14,013,043
Central electrolyser operates under a different electricity settlement price to HRSs		Scenario 19	11,413,468	2,508,073	124,569	13,796,972
		Scenario 20	11,531,285	2,508,134	124,569	13,914,850
		Scenario 21	11,609,752	2,508,174	124,569	13,99,3357
		Scenario 22	11,668,661	2,508,206	124,569	14,052,298
Central electrolyser operates under the same electricity settlement price as the HRSs		Scenario 23	11,413,468	2,508,073	124,569	13,796,972
		Scenario 24	11,531,285	2,508,134	124,569	13,914,850
		Scenario 25	11,609,752	2,508,174	124,569	13,993,357
		Scenario 26	11,668,661	2,508,206	124,569	14,052,298

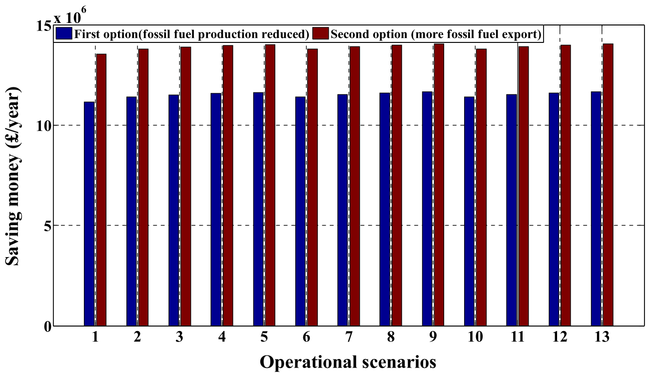

Fig. 12. Comparison of two options for adjusting the oil market in response to renewable energy penetration in terms of CO_2 reduction using 2030-Cost assumptions.

the scenario where exports were increased, whereas this difference rises to 82% with the 2030 SCC values, even with the clear increase in oil prices to 2030.

9. Conclusion

This paper focused on the economic benefits that can be derived from the uptake of renewable energy (RE) resources and consequent CO_2 emission reductions. In this study, the renewable energy is produced from wind turbines and photovoltaics (PV) to meet the consumption of the Green Mountain region of Libya, which represents 6% of the country's total energy demand. The sizing of the RE generators is based on the average electricity demand in this area. Due to the stochastic nature of renewable energy output and frequent mismatches between supply and demand, this study explores how temporary surpluses of energy can be absorbed by electrolysers to produce hydrogen. This is used as a 'clean' fuel that is dispensed to cars, powered by of fuel cells, (whose number is based on today's fleet) at six hydrogen refueling stations (HRSs) across the coastal city of Darnah.

The social carbon cost (SCC) of 2015 and 2030 were used in this paper, as were the expected oil and natural gas prices for the same dates. Using a range of scenarios, two main options were evaluated for the potential economic benefits of RE deployment where the responsive demand capability of electrolysers is used to mitigate the variability of renewable power output. The first option is to reduce fossil fuel production because its consumption within Libya is reduced by the integration of RE into the electricity supply network. The economic benefit here is derived from the reduction of CO_2 emissions in both electricity and transport sectors. The second option is to continue producing fossil fuels at the same level, despite RE deployment, which leads to more being available for export and therefore higher trade revenues.

Under 2015-Costs and prices, the second option (producing the same amount and exporting more fossil fuel) is preferable, from an economic viewpoint, compared with reducing fossil fuel production to reflect the reduced consumption arising from RE penetration into the Libyan market. In all cases, the first option makes less money, and does so by a considerable margin. The revenue raised when production is adjusted downwards in response to reduced domestic consumption is only 39% of that derived by maintaining the same levels of production and exporting the resulting surplus.

By 2030, the margin is much less, according to estimates in the literature for the SCC in that year. The first option (reducing production) is closer to being competitive with the second (increasing exports) as revenues represent nearly 82% of those achieved under the latter, despite the expectation of higher fossil fuel prices in 2030.

Global trends towards reducing GHG emissions and rapidly falling RE technology prices point to the inevitability of higher penetrations of renewables into energy systems. Today's oil-exporting countries should therefore respond to the steps taken by oil-importing countries to increasingly integrate renewables by trying to become RE exporters rather than remaining simply fossil fuel exporters. Some oil-exporters, like Libya, are in a strong position to eventually become major renewable energy producers. Libya's location and climate offer the promise of being able to produce and export renewable energy to Europe in the future. Exploiting the demand-shaping capability of electrolysis, the production of hydrogen offers a grid-balancing tool, plus a source of emission-free fuel to be used locally potentially exported via pipeline. These steps would reduce CO_2 emissions while increasing monetary income due to the high value of SCC that is anticipated in the future.

This study was focused on a specific region of Libya, but using wider data sources, it could be extended to include the whole country and used to guide government policy in ways that would support a renewable energy industry in the country as it emerges from its current political turmoil and embarks on a stable and sustainable future.

The main limitations to this study arose from the shortage of data available for Libya, particularly weather and energy demand data. In addition, some information was out of date, such as the emissions data collected from the most recent report of the General Electricity Company of Libya (GECOL), which was published in 2010. Another obstacle was the lack of awareness and understanding of the SCC concept, even among officials, which hampered the gathering of accurate information that could have given clearer results.

Appendix A

Scenario 1

Using 2015-Cost assumptions, electrolysers are located onsite at HRSs and there is no central electrolyser. Equipment capacities in this scenario are taken as the default for electrolyser and storage sizes at the HRS. Table A.1 presents a summary of this scenario.

Scenario 2

Using 2015-Cost assumptions, electrolysers of double the default capacity are located onsite at HRSs and there is no central electrolyser. The default capacity hydrogen is assumed for stores at each HRS. In this scenario, the size of electrolysers (and therefore compressors) is twice that of Scenario 1 and the new cost of these components is taken into account. The economic assessment and average hydrogen cost for Scenario 2 are presented in Table A.2.

Scenarios 3, 4 and 5:

Using 2015-Cost assumptions, electrolysers of three times the default capacity are located onsite at HRSs and there is no central electrolyser. Storage capacity is 1½ times, twice and three times the default size respectively. Table A.3 shows the electricity price for Scenarios 3, 4 and 5 throughout the year.

Scenarios 6, 7, 8 and 9

Using 2015-Cost assumptions, a large central electrolyser and hydrogen store is deployed in conjunction with electrolysers and stores of default capacity at HRSs. The central electrolyser operates under a different electricity settlement price to the HRSs. Scenarios in this group vary according to the sizes of central electrolyser and storage capacity. The amount of energy consumed

Table A.1
Hydrogen production cost details for 2015 with default-capacity electrolysers and hydrogen stores at HRSs only (no central electrolyser or storage is present).

HRSs	Cost					
	Investment cost (£/year)	Water cost (£/year)	Compressor electricity cost (£/year)	Electrolyser electricity cost (£/year)	Hydrogen production (kg/year)	Average price (£/kg)
HRS 1	230,364	1064	5,011	75,631	31,082	10.00
HRS 2	285,987	1351	5,843	94,229	39,487	9.80
HRS 3	731,128	3609	17,443	261,345	105,475	9.60
HRS 4	463,440	2160	10,435	155,101	63,122	10.00
HRS 5	1,026,705	5183	23,912	368,025	151,461	9.40
HRS 6	600,420	2677	13,013	191,272	78,216	10.30

Table A.2
Hydrogen production cost details for 2015 with electrolysers of twice the default size and default-capacity hydrogen stores at HRSs (no central electrolyser or storage is present).

HRS	Cost					
	Investment cost (£/year)	Water cost (£/year)	Compressor electricity cost (£/year)	Electrolyser electricity cost (£/year)	Hydrogen production (kg/year)	Average price (£/kg)
HRS 1	299,354	1370	4,233	51,473	40,033	9.00
HRS 2	390,526	1611	4,479	53,960	47,090	9.60
HRS 3	939,152	4451	14,459	178,224	130,076	8.70
HRS 4	594,309	2702	8,601	106,016	78,957	9.00
HRS 5	1,371,394	6399	18,743	243,724	186,994	8.80
HRS 6	772,894	3414	11,121	120,035	99,759	9.00

Table A.3
Techno-economic assessments of 2015-Cost scenarios with electrolysers of three times the default size and three different storage capacities (no central electrolyser).

Scenario		HRS					
		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
3x default size electrolyser and 1.5x default size storager (Scenario 3)	Hydrogen demand satisfaction (%)	82	65	87	87	77	83
	Average hydrogen price (£/kg)	11.50	12.80	11.50	11.80	11.50	11.80
	Total hydrogen demand satisfaction (%)			80			
	Total surplus energy consumed (%)			73			
3x default size electrolyser and 2x default size storage (Scenario 4)	Hydrogen demand satisfaction (%)	85	76	90	90	81	86
	Average hydrogen price (£/kg)	13.00	12.90	13.10	13.40	12.80	13.40
	Total hydrogen demand satisfaction (%)			84			
	Total surplus energy consumed (%)			76			
3x default size electrolyser and 3x default size storage (Scenario 5)	Hydrogen demand satisfaction (%)	87	79	92	91	84	88
	Average hydrogen price (£/kg)	16.10	15.30	16.50	17.00	15.40	16.80
	Total hydrogen demand satisfaction (%)			87			
	Total surplus energy consumed (%)			78			

Table A.4
Using 2015-Cost assumptions, various cases of central electrolyser size are operated under a different electricity settlement price to the HRSs.

Central electrolyser size (kg/day)		HRSs					
		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Scenario 6	Satisfaction of hydrogen demand (%)	71	67	77	74	77	74
	Average hydrogen price (£/kg)	12.00	12.40	11.30	11.50	12.40	12.60
	Total surplus energy consumed (%)			68			
	Satisfaction of total hydrogen demand (%)			75			
	Average central electrolyser hydrogen price (£/kg)			21.00			
Scenario 7	Satisfaction of hydrogen demand (%)	77	77	84	81	82	81
	Average hydrogen price (£/kg)	14.00	15.00	13.00	13.30	14.30	14.60
	Total surplus energy consumed (%)			73			
	Satisfaction of total hydrogen demand (%)			81			
	Average central electrolyser hydrogen price (£/kg)			26.00			
Scenario 8	Satisfaction of hydrogen demand (%)	84	82	87	86	87	86
	Average hydrogen price (£/kg)	17.40	19.00	15.50	16.00	17.70	17.80
	Total surplus energy consumed (%)			78			
	Satisfaction of total hydrogen demand (%)			86			
	Average central electrolyser hydrogen price (£/kg)			34.00			
Scenario 9	Satisfaction of hydrogen demand (%)	88	87	89	89	90	89
	Average hydrogen price (£/kg)	22.30	24.60	19.30	20.00	22.70	22.40
	Total surplus energy consumed (%)			80			
	Satisfaction of total hydrogen demand (%)			89			
	Average central electrolyser hydrogen price (£/kg)			46.40			

Table A.5
Assessments of the system under different sizes of central electrolyser when the central electrolyser runs under the same settlement electricity price as the HRSs (2015-Cost scenario).

Central electrolyser size (kg/day)		HRSs					
		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Scenario 10	Satisfaction of hydrogen demand (%)	65	66	76	69	82	74
	Average hydrogen price (£/kg)	12.00	12.50	11.60	11.80	12.60	11.80
	Total surplus energy consumed (%)	68					
	Satisfaction of total hydrogen demand (%)	75					
	Average central electrolyser hydrogen price (£/kg)	15.70					
Scenario 11	Satisfaction of hydrogen demand (%)	71	76	81	78	85	81
	Average hydrogen price (£/kg)	13.60	15.00	13.40	13.70	14.70	13.80
	Total surplus energy consumed (%)	73					
	Satisfaction of total hydrogen demand (%)	81					
	Average central electrolyser hydrogen price (£/kg)	20.20					
Scenario 12	Satisfaction of hydrogen demand (%)	81	83	85	84	88	85
	Average hydrogen price (£/kg)	17.00	19.00	16.00	17.00	18.00	16.70
	Total surplus energy consumed (%)	77					
	Satisfaction of total hydrogen demand (%)	86					
	Average central electrolyser hydrogen price (£/kg)	26.00					
Scenario 13	Satisfaction of hydrogen demand (%)	86	87	88	88	91	88
	Average hydrogen price (£/kg)	22.70	25.00	20.00	21.50	24.00	21.30
	Total surplus energy consumed (%)	80					
	Satisfaction of total hydrogen demand (%)	89					
	Average central electrolyser hydrogen price (£/kg)	37.00					

Table A.6
Hydrogen production cost details for 2030 with default-capacity electrolysers and hydrogen stores at HRSs only (no central electrolyser or storage is present).

HRSs	Cost					
	Investment cost (£/year)	Water cost (£/year)	Compressor electricity cost (£/year)	Electrolyser electricity cost (£/year)	Hydrogen production (kg/year)	Average price (£/kg)
HRS 1	107,450	1156	5,830	105,298	33,779	6.50
HRS 2	136,279	1471	7,123	132,709	42,977	6.50
HRS 3	334,089	3904	20,045	360,085	114,077	6.30
HRS 4	212,380	2338	11,889	214,761	68,313	6.50
HRS 5	477,629	5666	27,995	516,873	165,566	6.20
HRS 6	275,007	2942	15,042	269,288	85,966	6.50

Table A.7
Hydrogen production cost details for 20 130 with electrolysers of twice the default size and default-capacity hydrogen stores at HRSs (no central electrolyser or storage is present).

HRSs	Cost					
	Investment cost (£/year)	Water cost (£/year)	Compressor electricity cost (£/year)	Electrolyser electricity cost (£/year)	Hydrogen production (kg/year)	Average price (£/kg)
HRS 1	197,176	1419	4,835	68,462	41,459	6.60
HRS 2	242,207	1778	6,052	80,072	51,945	6.40
HRS 3	632,365	4611	15,746	236,103	134,752	6.60
HRS 4	400,143	2722	9,130	134,812	79,556	6.90
HRS 5	880,049	6815	23,434	339,900	199,148	6.30
HRS 6	518,574	3515	12,393	164,097	102,718	6.80

depends upon the electrolyser capacity in each scenario. Thus, 59,971 kWh is absorbed in Scenario 6, which accounts for 38% of the available surplus energy, 105,000 kWh in Scenario 7 (60% of surplus energy), 165,000 kWh in Scenario 8 (80% of surplus energy), and 265,000 kWh in Scenario 9 (95% of surplus energy). Table A.4 summarises the economics of each option in terms of achieving the main objectives of the research, namely responsive power demand, the satisfaction of hydrogen demand and meeting hydrogen price targets.

Scenarios 10, 11, 12 and 13

Using 2015-Cost assumptions, the capacity of the central electrolyser varies the same as in Scenarios 6 to 9, above. However, in this case (Scenarios 10 to 13), the central electrolyser is subject to the same electricity settlement price as the HRSs. Table A.5 presents an economic summary of Scenarios 10–13.

Scenario 14

This is the same as Scenario 1, but uses 2030-Cost assumptions instead. Electrolysers are located onsite at HRSs and there is no central electrolyser. Equipment capacities in this scenario are the default for electrolyser and storage sizes at the HRS. Table A.6 presents a summary of this scenario.

Scenario 15

This is the same as Scenario 2, but uses 2030-Cost assumptions instead. Electrolysers (and therefore compressors) of double the default capacity are located onsite at HRSs and there is no central electrolyser. The default capacity hydrogen is assumed for stores at each HRS. The economic assessment and average hydrogen cost for Scenario 15 are presented in Table A.7.

Table A.8
Techno-economic assessments of 2030-Cost scenarios with electrolysers of three times the default size and three different storage capacities (no central electrolyser).

Scenario		HRS					
		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
3x default size electrolyser, 1.5x default size storage (Scenario 16)	Hydrogen demand satisfaction (%)	83	75	90	89	80	86
	Average hydrogen price (£/kg)	8.40	8.00	8.50	8.60	8.10	8.60
	Total hydrogen demand satisfaction (%)	83					
	Total surplus energy consumed (%)	76					
3x default size electrolyser, 2x default size storage (Scenario 17)	Hydrogen demand satisfaction (%)	86	81	92	89	86	88
	Average hydrogen price (£/kg)	9.70	9.00	10.00	10.40	9.20	10.00
	Total hydrogen demand satisfaction (%)	87					
	Total surplus energy consumed (%)	79					
3x default size electrolyser, 3x default size storage (Scenario 18)	Hydrogen demand satisfaction (%)	90	85	93	92	88	92
	Average hydrogen price (£/kg)	12.20	11.00	12.80	13.40	11.40	12.80
	Total hydrogen demand satisfaction (%)	89					
	Total surplus energy consumed (%)	81					

Table A.9
Using 2030-Cost assumptions, various cases of central electrolyser size are operated under a different electricity settlement price to the HRSs.

Central electrolyser size (kg/day)		HRS					
		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Scenario 19	Satisfaction of hydrogen demand (%)	74	72	81	77	80	78
	Average hydrogen price (£/kg)	7.50	7.90	7.10	7.10	7.60	7.60
	Total surplus energy consumed (%)	65					
	Satisfaction of total hydrogen demand (%)	78					
	Average central electrolyser hydrogen price (£/kg)	12.60					
Scenario 20	Satisfaction of hydrogen demand (%)	80	81	86	84	85	84
	Average hydrogen price (£/kg)	8.40	9.10	7.80	8.00	8.50	8.50
	Total surplus energy consumed (%)	69					
	Satisfaction of total hydrogen demand (%)	84					
	Average central electrolyser hydrogen price (£/kg)	14.80					
Scenario 21	Satisfaction of hydrogen demand (%)	87	87	89	88	89	88
	Average hydrogen price (£/kg)	10.0	10.90	8.80	9.10	10.00	9.80
	Total surplus energy consumed (%)	73					
	Satisfaction of total hydrogen demand (%)	88					
	Average central electrolyser hydrogen price (£/kg)	18.70					
Scenario 22	Satisfaction of hydrogen demand (%)	91	90	92	92	92	91
	Average hydrogen price (£/kg)	12.30	13.60	10.60	11.20	12.20	12.00
	Total surplus energy consumed (%)	75					
	Satisfaction of total hydrogen demand (%)	91					
	Average central electrolyser hydrogen price (£/kg)	25.30					

Table A.10
Assessments of the system under different sizes of central electrolyser when the central electrolyser runs under the same settlement electricity price as the HRSs (2030-Cost scenario).

Central electrolyser size (kg/day)		HRS					
		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Scenario 23	Satisfaction of hydrogen demand (%)	69	70	78	73	84	77
	Average hydrogen price (£/kg)	7.40	7.80	7.20	7.30	7.80	7.20
	Total surplus energy consumed (%)	70					
	Satisfaction of total hydrogen demand (%)	78					
	Average central electrolyser hydrogen price (£/kg)	10.30					
Scenario 24	Satisfaction of hydrogen demand (%)	77	80	85	82	87	83
	Average hydrogen price (£/kg)	8.20	90.00	80.00	8.20	8.70	8.10
	Total surplus energy consumed (%)	76					
	Satisfaction of total hydrogen demand (%)	84					
	Average central electrolyser hydrogen price (£/kg)	12.00					
Scenario 25	Satisfaction of hydrogen demand (%)	85	86	88	87	91	87
	Average hydrogen price (£/kg)	9.80	10.70	9.00	9.20	10.20	9.20
	Total surplus energy consumed (%)	79					
	Satisfaction of total hydrogen demand (%)	88					
	Average central electrolyser hydrogen price (£/kg)	15.20					
Scenario 26	Satisfaction of hydrogen demand (%)	90	90	91	91	92	91
	Average hydrogen price (£/kg)	12.00	13.70	10.60	11.30	12.60	11.000
	Total surplus energy consumed (%)	82					
	Satisfaction of total hydrogen demand (%)	91					
	Average central electrolyser hydrogen price (£/kg)	21.00					

Scenarios 16, 17 and 18:

Scenarios 16, 17 and 18 are the same as Scenarios 3, 4 and 5 respectively, but use 2030-Cost assumptions instead. Electrolysers of three times the default capacity are located onsite at HRSs and there is no central electrolyser. Storage capacity is 1½ times, twice and three times the default size respectively. Table A.8 shows the electricity price for Scenarios 16, 17 and 18 throughout the year.

Scenarios 19, 20, 21 and 22

Scenarios 19, 20, 21 and 22 are the same as Scenarios 6, 7, 8 and 9 respectively, but use 2030-Cost assumptions instead. A large central electrolyser and hydrogen store is deployed in conjunction with electrolysers and stores of default capacity at HRSs. The central electrolyser operates under a different electricity settlement price to the HRSs. Scenarios in this group vary according to the sizes of central electrolyser and storage capacity. Energy consumed is 59,971 kWh in Scenario 19 (38% of the available surplus energy), 105,000 kWh in Scenario 20 (60% of surplus energy), 165,000 kWh in Scenario 21 (80% of surplus energy), and 265,000 kWh in Scenario 22 (95% of surplus energy). Table A.9 summarises the economics of each option in terms of achieving the main objectives of the research, namely responsive power demand, the satisfaction of hydrogen demand and meeting hydrogen price targets.

Scenarios 23, 24, 25 and 26

Scenarios 23, 24, 25 and 26 are the same as Scenarios 10, 11, 12 and 13 respectively, but use 2030-Cost assumptions instead. The capacity of the central electrolyser varies the same as in Scenarios 19 to 22, above. However, in this case (Scenarios 23 to 26), the central electrolyser is subject to the same electricity settlement price as the HRSs. Table A.10 presents an economic summary of Scenarios 23–26.

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