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On the outlook for solar thermal hydrogen production in South Africa

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ABSTRACT

Global warming and tightening environmental legislation is putting pressure on divesting from fossil fuel in the energy sector, with the transport sector likely to see the biggest changes. Current alternative energy sources are electric vehicles and hydrogen. Conventional hydrogen production technologies are fossil fuel based, emitting significant amounts of CO_2 into the atmosphere. This paper explores various ways to integrate solar thermal technologies into hydrogen production to generate carbon free hydrogen in South Africa. South Africa's abundant solar resource indicates that the country may become a significant player in the hydrogen market. However, the high capital cost associated with solar thermal energy put solar thermal hydrogen at a price disadvantage against conventional production technologies. Significant market penetration for solar thermal hydrogen is not expected within the next decade, but cost reduction due to improved manufacturing techniques and larger manufacturing volumes might close the gap in the long term.

Introduction

Fossil fuels have become indispensable in the transport sector over the last century. Its continued use is under thread, due to the rapid depletion of the resource. Furthermore, burning fossil fuels release vast quantities of CO_2 into the atmosphere that contributes towards global warming. NO_x and hydrocarbons, also emitted by burning fossil fuels, cause smog and corresponding health issues in cities. The United Nation Climate Change Secretariat coordinates international efforts to mitigating the effect of climate change. A total of 192 countries have ratified its Kyoto protocol and 179 its Paris agreement [1]. These countries are committed to reduce their CO_2 emissions, and tabled plans to reduce their carbon footprint. High cost and increasingly more stringent environmental regulations are expected to be strong drivers for divestment in fossil fuels in future.

Two technologies are currently competing as alternatives to the internal combustion engine in the mobility sector, namely electric cars and hydrogen fuel cells. Electric vehicles hold a slight advantage in that it can benefit from an existing electricity distribution network. Their batteries can act as a distributed energy storage system that may help to mitigate the inherent intermittent nature of renewable energy source. A limited range of ±100 km and long recharging times (±8 h) are seen as the main obstacles for large scale deployment. Ground-breaking work by Tesla managed to increase the range to over 400 km. Hydrogen fuel cells' main advantage over electric cars is their extended range (over 800 km) and rapid refuelling. High cost and lack of infrastructure are the most important barriers in the way of large scale deployment; both are expected to respond favourably to large production volumes. Of course, CO_2 mitigation targets can only be reached if electricity or hydrogen is produced from renewable energy sources.

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Japan embraced hydrogen fuel cells as the technology to replace the internal combustion engine, and today Japan is the world leader on the path towards a hydrogen economy. Significant hydrogen infrastructure development is underway in Tokyo in anticipation of the Tokyo Olympic Games in 2020 [2]. Japan aim to make a complete transition to carbon free hydrogen by 2040. The expected high demand for clean hydrogen in Japan creates export opportunities for countries blessed with ample renewable energy resources. In South Africa, the solar resource is particularly abundant, and this paper investigates several ways of integrating mainly concentrating solar energy (electricity and/or solar process heat) into various hydrogen production processes.

Only a few pilot hydrogen projects are operational in South Africa [3], with no hydrogen infrastructure currently available. The country's abundant solar and platinum group metals resources mean that it is well placed to develop a fuel cell industry [4] in future. Hydrogen is not mentioned in the South African Government's draft Integrated Resource Plan for 2018–2030 [5]. Hence, the domestic market is expected to have an insignificant impact on hydrogen production over the next decade, and this paper focus mainly on the export market, specifically to Japan. South Africa's potential competitiveness in this market is explored.

The vast majority (95%) of existing hydrogen production is by methane/steam reforming [6,7]. In South Africa, the hydrogen is of low purity and is destined for production of fertilizers. It is estimated that methane/steam reforming can produce hydrogen at about than 1 \$/kg [8–10], it suffers from high CO_2 emissions. Methane/steam reforming is at odds with Japan's goal of carbon free hydrogen. However, it might be possible to reduce the process's carbon footprint by substituting solar process heat for burning fossil fuels.

In alkaline low temperature electrolysis, an electric current is passed through a caustic aqueous solution. Water is decomposed into hydrogen at the cathode and oxygen at the anode. Low temperature electrolysis is a mature technology, responsible for almost 5% of current hydrogen production. Electrolyser units up to 2 MW are commercially available. Low temperature electrolyses only require electricity and water as inputs. Electricity consumption is about 45–50 kWh/kg H_2, whilst is consumes 10–12 l of H_2O/kg H_2 produced at a conversion efficiency of 80%. In order to be cost competitive, a low cost source of renewable electricity is required. Alkaline low temperature electrolysers are easy to operate, and flexible enough to accommodate the intermittent nature of electricity supply from renewable energy resources.

Proton exchange membrane technology is more suited for distributed hydrogen production (forecourt applications), but it is expensive, have a short service life compared to alkaline electrolysers and is commercially available only in the kilowatt range [11].

Dönitz et al. [12] and O'Brien [13] have shown that the electricity required for electrolysis decreased with increasing temperature, whilst the reaction efficiency also increases. This makes a strong case for high temperature steam electrolysis. Process heat is used to convert water into steam, and to raise the electrolyser temperature. The total electric and thermal energy requirement of the electrolyser remains fairly constant. As a heat engine is required to convert heat into work, electricity is generally more expensive than process heat. Substituting process heat for electricity reduces the production cost of hydrogen substantially. Reaction kinetics also increases with temperature, eliminating the need for a catalyst. On the down side, high temperature materials is a challenge, and the electrolyser is sensitive to temperature changes, making it less suited for integration with an intermittent energy source. Short electrolyser life and scale-up to MW range are some of the challenges that need to be addressed in commercialising high temperature steam electrolysis [14].

Thermo-chemical water splitting attracted a fair amount of attention from the high temperature gas (nuclear) reactor community [15]. Their focus is mainly in the temperature range 750 °C–900 °C that represents typical reactor outlet temperatures. Hence, most development concerned the hybrid sulphur and sulphur-iodine cycles which have maximum temperature requirements within this range. The University of Ontario's Institute of Technology, in collaboration with the Argonne National Laboratory and Atomic Energy Canada developed the hybrid Cu–Cl reactor, as its temperature requirements matches the reactor outlet conditions (550 °C) of the Canadian Deuterium Uranium reactor. This incidentally the same as the outlet temperatures for existing molten salt central receiver solar systems. Apart from the sulphur-iodine cycle, these cycles require electrolysis, but at lower electricity input than water or steam electrolysis. In most of these cycles, solar process heat with thermal energy storage can potentially replace nuclear heat, provided that the cycle can cope with limited interruptions.

Metal oxide redox reactors rely on a two-step reaction. In the first step, oxygen is removed from the oxide at high temperature ($1000\,°C < T < 1500\,°C$ depending on the metal oxide), leaving it in a reduced state. During the second step, steam is passed through the reactor, and oxygen is stripped from the water molecule, and pure hydrogen leaves the reactor. Solar energy can be absorbed directly by the oxide [16], making for a fairly simple design. A lack of high temperature storage technologies, and operating in an oxygenating/reducing mode, potentially limits production volumes. On the other hand, redox reactors require only a heat input, and have the potential to produce hydrogen at low cost.

Solar assisted steam/methane reforming

About 95% of H_2 production world-wide is by methane/steam reforming. It is also the only current technology used for hydrogen production by SASOL in South Africa. In the process, hydrocarbon fuel is used as both heat source and feedstock. Replacing the hydrocarbon fuel heat source with solar energy will reduce the CO_2 emissions from steam reforming. Temperature requirements are challenging at about 900 °C for equilibrium reactions [17]. If South Africa is to supply the Japanese market, steam reforming has a limited window of application. The Japanese want to move from CO_2 lean, to CO_2 free hydrogen production by 2040. However, existing technology can be used in the meantime, allowing for early market entry. Solar integration will require little research and development outside optimizing plant configuration. On the downside, production facilities are located at sites that receive only moderate solar irradiation. A practical integration would require a solar salt parabolic trough/central receiver, two-tank solar salt thermal energy storage system and a process heat exchanger, as shown in Fig. 1. At 500 °C, the temperature requirement is at the upper limit of Hitec salt. The relative simplicity of the solution means that most plant components and construction materials can be sourced locally to the benefit of the local economy.

A 300 MW_t parabolic trough plant at Sasol I was evaluated using NREL's system advisor model [2,18] with DNI data from www.soda-pro.com for Sasolburg (see Fig. 2 for location). Assuming that the methane/steam reforming process is vulnerable to interruptions, a large solar multiple and ample thermal energy storage was adopted. The levelized cost of heat reached a minimum for a solar multiple of 4, and 18 h of thermal energy storage. With this plant configuration, solar process heat is not available for 231 h per year. Rather than increasing the solar field, co-firing using natural gas was adopted to bridge the gap when solar heat is not available. It is assumed that gas firing to the equivalent of 100% of the process heat demand is already available, as this conforms to the original plant design. Furthermore, assuming a plant live of 20 years, end of production would roughly coincide with Japan's move to carbon free hydrogen by 2040, should construction starts soon. Alternatively, the plant might provide carbon lean hydrogen to the domestic market beyond 2040, provided that a domestic hydrogen market and infrastructure has been developed by 2040.

Plant cost estimates were adopted from the SunShot 2020 targets [19]. Parabolic trough plant is a mature, and hence low risk technology, hence an interest rate equal to the repo rate (6.5%) was adopted, with an inflation rate mid-range of the South African Reserve Bank's inflation targets (4.5%). It was assumed that the loan term is 25 years. A draft carbon tax ($8.50/ton CO_2) bill for South Africa was tabled in 2015, but hasn't been signed into law. It was assumed that a carbon tax would be adopted shortly, and the full effect of carbon taxes was taken into account.

Sasolburg is situated on the banks of the Vaal River, and it is assumed that water may be extracted from the river system at municipal rates of 0.30 $/m^3.

With these parameters, the levelized cost of solar heat worked out at 0.03 $/kWh$_t$, and the gas savings was 126 800 tons per year. However, at a natural gas price of 3 $/GJ for large industrial users in South Africa [20], integrating solar heat into the methane/steam reforming process results in a net loss of $39 million per year compared to conventional methane/steam reforming. This translates into an additional cost of 0.24 $/kg H_2 or a total hydrogen production cost of 1.25–1.50 $/kg.

Processing (compression, liquefaction or incorporating it in a liquid organic carrier) of hydrogen for storage, storage on site, and transport costs of hydrogen were excluded from this study; Harvego et al. [9] estimated that compression would add 1.75 $/kg to the production cost, whilst using a liquid organic hydrogen carrier would come in much lower at 0.27 $/kg [21].

Low temperature alkaline electrolysis powered by solar photovoltaic and wind

South Africa had 1360 MW wind, 1474 MW photovoltaic, and 200 MW concentrated solar thermal power operational by the end of 2016 [22]. The tariff for both new build wind and photovoltaic power was 0.045 $/kWh$_e$ [22]. A network charge of 0.005 $/kW$_e$ [5,23,24] was added to the electricity cost, whilst 5% line losses were assumed. Wind and photovoltaic plant are distributed widely throughout South Africa, and no attempt was made to find an average distance between the electricity and hydrogen production plants. It is concluded that South Africa has sufficient wind and photovoltaic capacity to power a 150 MW_e low temperature alkaline water electrolyser and associated reverse osmosis desalination plant at the coast (Saldanha Bay), although dips in power supply below 150 MW_e will occur on occasion. The lowest power production by wind only in 2016 was recorded in the month of May. During the night, power output by wind only drops below 150 MW_e 18% of the time. It is assumed that the combined output by wind and photovoltaic power plants will never dip below 150 MW_e during daylight hours. Raw data was not available to find the annual integrated hydrogen

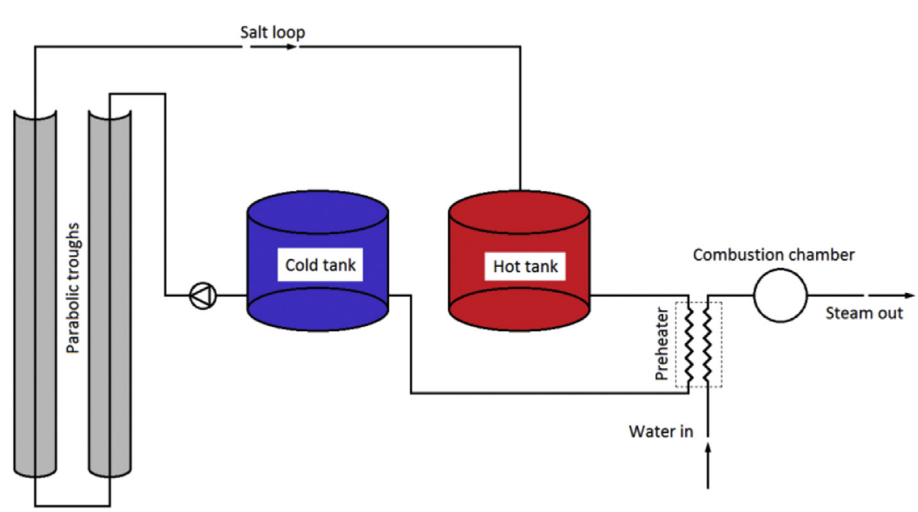

Fig. 1 – Parabolic trough plant supplying solar preheating to methane/steam reforming plant.

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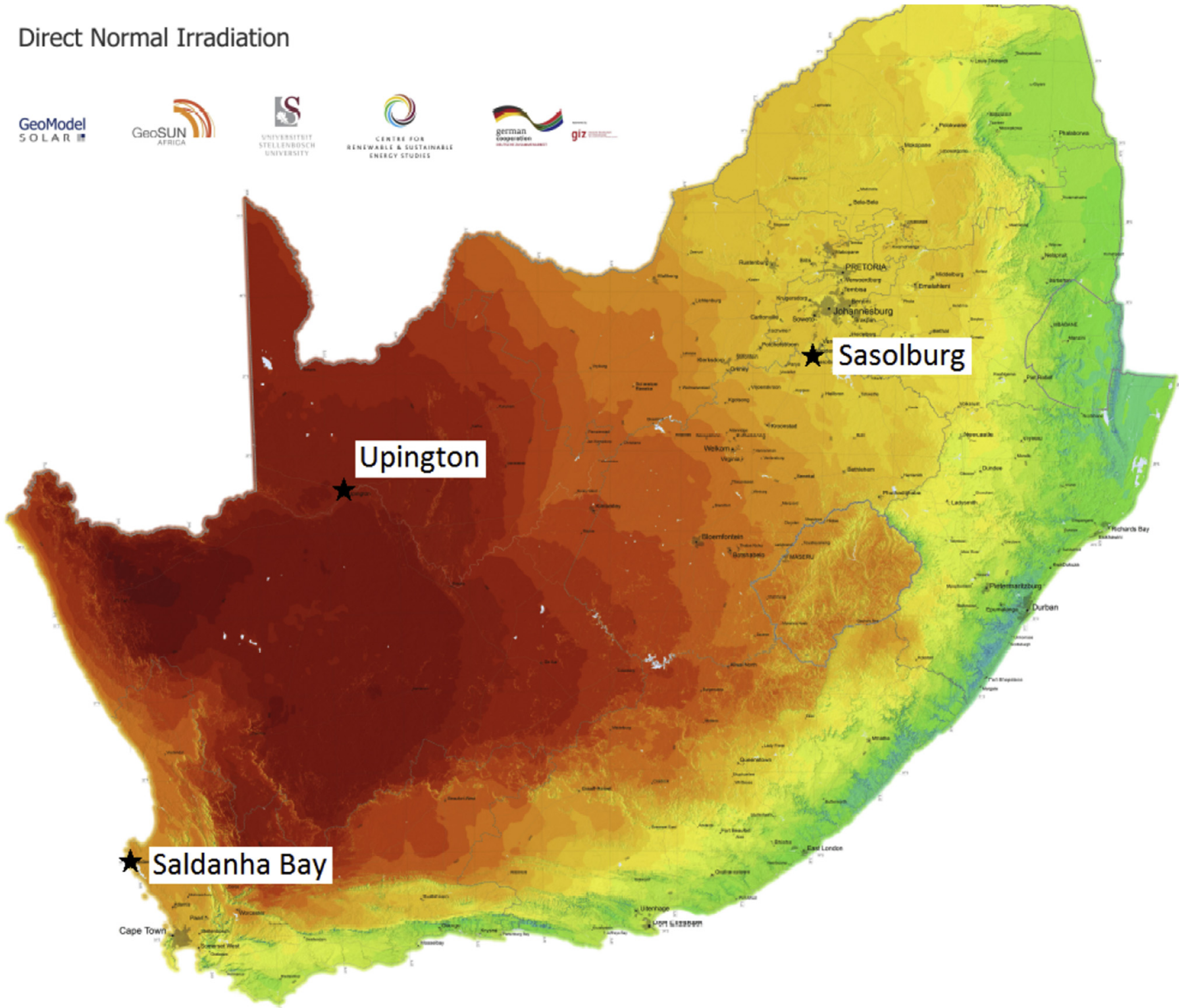

Fig. 2 – DNI map of South Africa, showing sites discussed in this work. (Source: GeoSun Africa https://geosun.co.za/).

production by wind and photovoltaics; to allow for low power incidents, a capacity factor of 90% was applied. This assumption conservatively implies total shut-down of the electrolysers if the available electricity supply drops below 150 MW_e.

Capital cost and electricity consumption for the reverse osmosis plant in Table 1 were calculated according to Al-Karaghouli and Kazmerski [25]. The reverse osmosis plant is capable of delivering the 241 Ml fresh water per year required by the low temperature alkaline electrolysis plant at a cost of 2.90 $/m^3. Electricity consumption was split between the reverse osmosis and electrolyser plants; however, the reverse osmosis plant consumes only 0.1% of the electricity needed by the electrolyser. Assumptions for low temperature alkaline electrolysis plant shown in Table 2 were taken from Shaner et al. [26]. Their data falls within the ranges suggested more recently by Saba et al. [27].

Using wind and photovoltaic power, a 150 MW_e low temperature alkaline water electrolysis plant should be capable of producing 16 819 tonnes (less than 2% of anticipated Japanese demand) of hydrogen per year at a levelized cost of 4.42 $/kg. However, the total installed wind and photovoltaic capacity in South Africa would be unable to supply energy continuously to this plant, limiting opportunities to increase hydrogen production for export purposes.

Table 1 – Cost items for reverse osmosis plant.

Item	Cost
Civil work	15 $/m^2
Reverse osmosis unit	1207 $/m^3/day
Water treatment plant	55 $/m^3/day
Seawater intake & pumping station	372 $/m^3/day
Contingency	7% of capital cost
Indirect cost	11% of installed cost
Operating and maintenance cost	0.56 $/m^3/year
Electricity consumption	4.46 kW_e/m^3/day

Table 2 – Assumptions for low temperature alkaline water electrolysis plant.

Item	Cost
Stack	400 $/kW$_e$ (stack is replaced every 10 years)
Balance of plant	570 $/kW$_e$
Contingency	35% of capital cost
Operating and maintenance cost	5% of capital cost
Efficiency	65%
Electricity consumption	62.5 kWh$_e$/kg H_2
Water consumption	11 l/kg H_2
Cost of desalinated sea water	0.965 $/m^3 (for 40 000 m^3/day RO plant)

Concentrated solar electricity and low temperature electrolysis

Low temperature alkaline electrolysis is a mature technology, commercially available in units up to 2 MW. Clusters of these units can be linked together for large scale hydrogen production for export. CSP is also a mature technology, the combination of two mature technologies allows for early market entry. Another benefit is that concentrated solar power stations can be built in regions with high solar resource, whilst the electrolysis plant can conveniently be located near a reliable water source and/or point of export. This would negate the need for long distance overland hydrogen transport infrastructure. Electricity from the solar thermal plant can be fed to the electrolysis plant via the existing distribution network.

South Africa is a water scarce country and to avoid stressing its limited water sources, desalinated sea water is the preferred feedstock for the electrolyser. A reverse osmosis desalination plant, powered by concentrated solar electricity, would sit next to the electrolysers on the coast.

Distributing CSP plants would make for more reliable energy supply, as Hydrogen production would not be affected significantly by local weather conditions at any single concentrated solar power plant. Excess electricity can be sold to other customers. As Rankine cycle efficiency increases with live steam temperature, a Solar Salt™ central receiver plant with two-tank solar salt thermal energy storage is the preferred option, as shown in Fig. 3.

A 150 MWe nett molten salt supercritical central receiver plant located at Upington in the Northern Cape Province was simulated, using DNI data supplied by GeoSUN for the 2016 calendar year. The electrolyser and reverse osmosis plants are situated at Saldanha Bay, the closest deep water harbour to Upington, about 600 km away, as shown in Fig. 2. Electricity from the CSP plant is used to desalinate water at a coastal site using reverse osmosis, as well as the energy supply to a low temperature electrolysis plant. Line losses of 5% per 1000 km [28] and a network charge of 0.005 $/kWh (ESKOM Tariffs) are included in the calculations.

Hoffmann & Madaly [29] found that the lowest levelized electricity cost for a 100 MW$_e$ plant at Upington is was achieved for a plant with a solar multiple of 3 and 13 h of thermal energy storage. The same configuration is adopted in this work. The live steam temperature and pressure were chosen as 545 °C and 24 MPa respectively, and the steam turbine has three extraction points for regenerative heating. An air cooled condenser with constant initial temperature difference of 25 °C [30] rejects the waste heat to the atmosphere. Steam properties were evaluated using the Microsoft Excel add-in X-steam.

The solar field were simulated using NREL's SolarPILOT [31] software for an external cylindrical receiver and a biomimetic heliostat field using the optimized field spacing proposed by Noone et al. [32]. Heliostats are 12.68 m wide by 9.49 m high, giving a total reflective surface area of 120 m^{2}and the tower is 300 m tall. Design point DNI was taken as 13:00 South African Standard time, on 21 March 2016; it is within 8 min of solar noon at Upington. The field was deliberately overdesigned, and heliostats with the lowest overall efficiency were subsequently removed from the field until the design heat input was collected at the receiver.

Convection losses from the receiver were calculated using a mixed convection heat transfer coefficient suggested by Young and Uhlrich [33]. Air temperature and wind speed were recorded at 2 m, and 10 m above ground level respectively. The wind speed at receiver height was calculated from a one-seventh power law, and the air temperature from the adiabatic lapse rate. Assuming a uniform solar heat flux, the receiver external surface temperature was calculated from heat conduction through the tube wall and the mean salt temperature. Radiation losses were based on the receiver surface temperature the ground level (air) temperature,

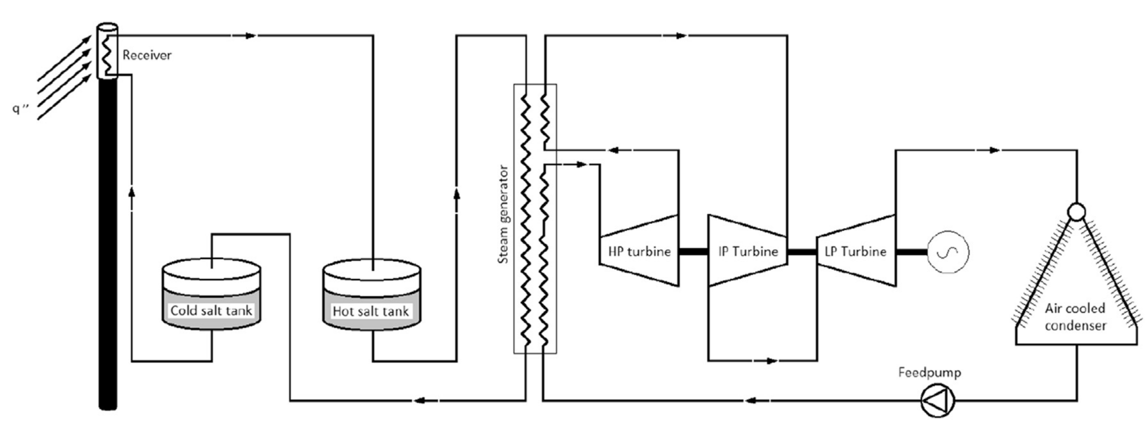

Fig. 3 – Conventional molten salt central receiver plant.

assuming a view factor of one (receiver is totally enclosed by its environment).

Plant cost estimates shown in Table 3 were adopted from the SunShot 2020 targets [19]. Several supercritical fossil fuel fired steam plants are in operation around the world. It is assumed that small supercritical steam turbines will become available in the near future; currently, the smallest available supercritical steam turbines have a 400 MW_e rating [34]. Hence small supercritical steam turbines are considered a somewhat immature technology. To compensate for the higher risk, an interest rate midway between the repo rate and prime lending rate was adopted (8%). The inflation rate is assumed to be 4.5%, that is midrange of the South African Reserve Bank's inflation targets, and the loan term is 25 years.

The reverse osmosis and low temperature alkaline electrolyser plant are identical to those used for wind and photovoltaic power. Cost assumptions for them are given in Table 1 and Table 2 respectively.

Taxes, plant salvage value, demolition costs and site rehabilitation were excluded from all economic evaluations. Furthermore, a plant availability of 100% was assumed. This was the case for all other technologies, as technologies were compared on their relative performance against each other. Based upon these assumptions, it is estimated that combining a concentrated solar thermal power plant at Upington with a battery of low temperature alkaline water electrolysis units and a reverse osmosis plant at Saldanha Bay would produce 21 272 tonnes of hydrogen per year at a levelized hydrogen production cost of 4.69 $/kg H_2.

Table 3 – Cost assumptions for concentrated solar thermal power plant.

Item	Cost
Heliostats	120 $/m^2
Land preparation	20 $/m^2
Tower and receiver	170 $/kW$_t$
Thermal energy storage	22 $/kWh$_t$
Power block	1100 $/kW$_e$
Contingency	10% of capital cost
Indirect cost	24.7% of installed cost
Operating & maintenance	50 $/kW$_e$ gross/year
Parasitic losses	10% of generator output

High temperature steam electrolysis

The required temperatures for high temperature electrolysis range from 600 °C to 1000 °C, with the highest conversion efficiencies occurring above 800 °C. Temperatures above 800 °C would set targets to the solar plant that is just outside the reach of current commercial technologies. The proposed solar plant shown in Fig. 4 comprises of 2 m^2 heliostats [35], a centrifugal particle receiver [36] with particle bin storage, and a process heat exchanger [37]. The solar plant is designed to deliver 10 MW_t energy, and the target radiation flux on the receiver is set to 1000 kW/m^2 at receiver aperture for a solar multiple of 3 in order to achieve the high particle temperatures required. It is assumed that the plant is situated at Upington in the Northern Cape Province, and the design DNI is based upon 13:00 on 21 March. Electricity for the high temperature steam electrolyser is supplied from nearby CSP plants, and river water serves as feedstock.

Heliostats are arranged in a cornfield configuration as shown in Fig. 5, and the field is limited to the projection of the back of the receiver cavity through the receiver aperture onto the ground. The receiver axis is at an angle of 50° with the ground, and it has an aspect ratio of *L/D* of 1.5. Receiver diameter and tower height were adjusted until both design targets for receiver heat flux and heat absorption were reached. Both conditions were met for a 7 m diameter receiver and a 200 m tall tower. No attempt was made to optimize the receiver diameter, aspect ratio, tower height or heliostat layout, solar multiple and energy storage. Heliostat field efficiency was calculated using SolarPILOT, and the receiver aperture was approximated by a flat, rectangular plate of the same area and inclination as the actual receiver. The initial field aperture was overdesigned, and the least efficient heliostats were removed from the field until the desired heat input was realized. View factors for radiation losses were calculated with the aid of the CFD code ANSYS Fluent, whilst it was assumed that convection losses are negligible.

It is assumed that high the temperature steam electrolyser can tolerate interruptions in operation, but needs to be boxed up at a constant temperature when process heat is not available. Notwithstanding, 18 h of thermal energy storage was adopted to achieve a high capacity factor. Electrolyser operation is terminated when less than 1 h worth of thermal

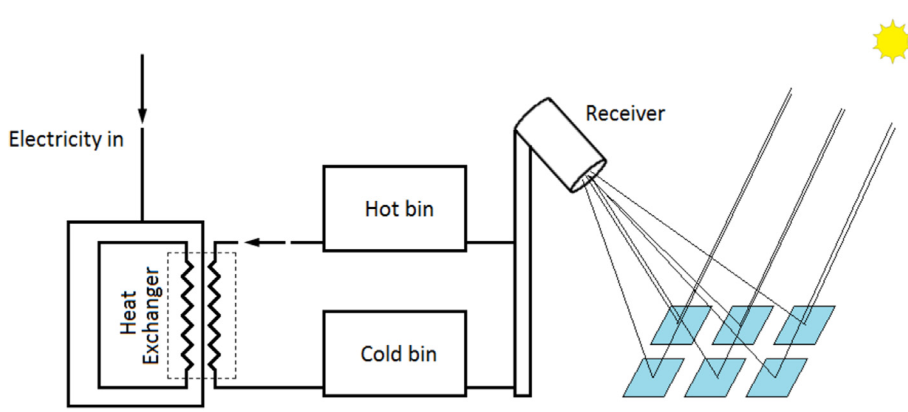

Fig. 4 – Proposed solar energy supply electrolysis plant for temperatures over 800 °C.

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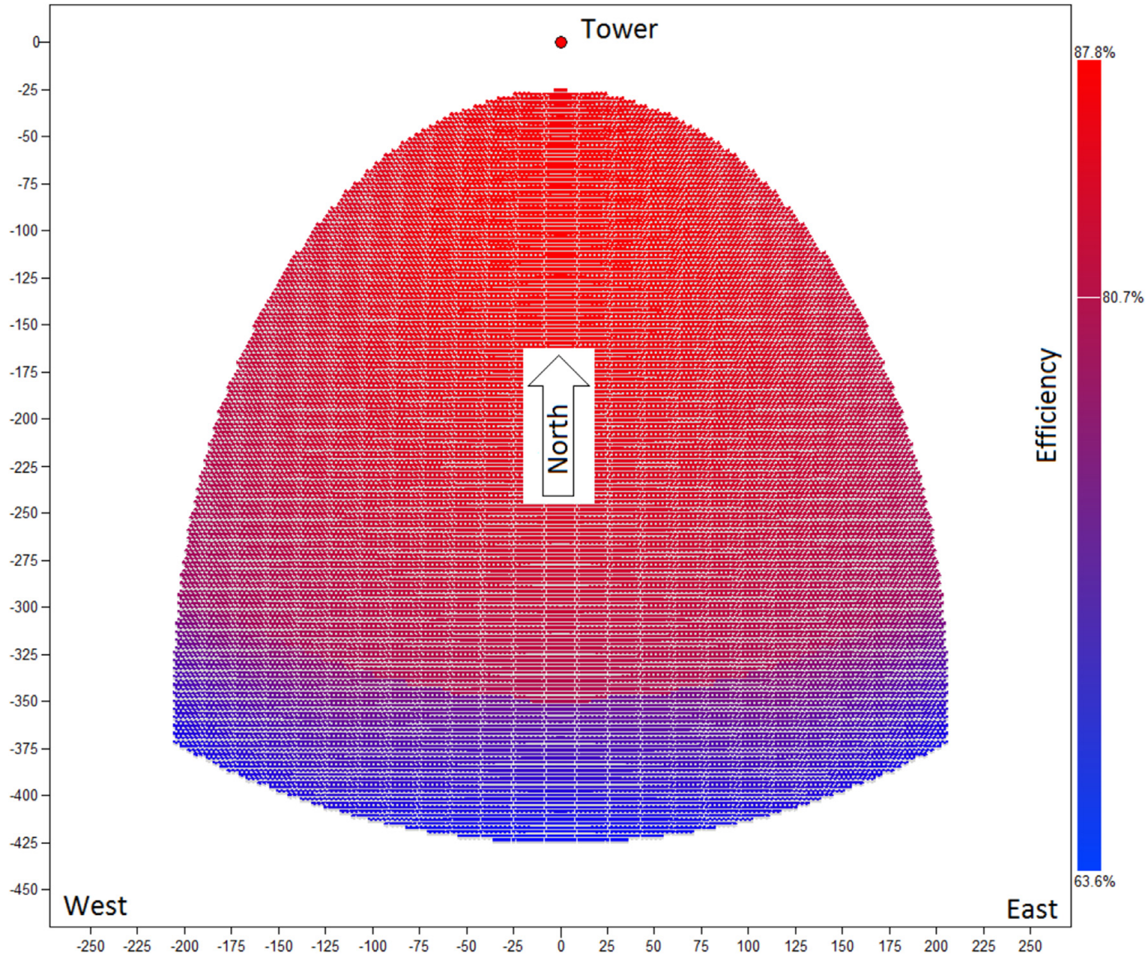

Fig. 5 – Heliostat field lay-out for downward inclined cavity receiver.

energy is left in storage, and the remaining energy is used to maintain reactor temperature. A continuous supply of electricity is presumably always available from five nearby CSP plants.

Plant component costs are listed in Table 4. The cost of heliostats was adopted from SunShot 2020 targets [19], whilst the receiver, storage and heat exchanger costs were based on estimates from Prosin et al. [37]. A prototype of the centrifugal receiver has been tested at the DLR, but to date, only analyses of the high temperature particle heat exchanger has been done. To account for the higher risk associated with this plant configuration, the interest rate was set equal to the prime lending rate (10.25%). Large scale transport infrastructure for hydrogen from Upington to the nearest deep water harbour does not exist, and it is assumed that hydrogen will initially be transported by road or rail.

Table 4 – Plant component costs used in the analysis.

Item	Cost	Source
Heliostats	120 $/m^2$	Mehos et al. [19]
Land preparation	20 $/m^2$	Mehos et al. [19]
Receiver & tower	222 000 $/m^2$ (aperture)	Prosin et al. [37]
HTF and storage	5 $/kWh	Prosin et al. [37]
Particles	0.05 $/kg	Prosin et al. [37]
Particle heat exchanger	888 $/kW	Prosin et al. [37]
Contingency	10% (of subtotal)	Mehos et al. [19]
Indirect cost	24.7% (of total)	Mehos et al. [19]

The energy requirements of the high temperature electrolysis plant were adopted from O'Brien [13] for an electrolyser temperature of 800 °C, as shown in Fig. 6. Commercial high temperature steam electrolysers are available in the hundreds of kilowatts range [38]; the solar plant can serve several of these electrolysers in parallel. Estimated capital cost for high temperature steam electrolysers range from 1400 €/kW$_e$–2 0000 €/kW$_e$ (Rivera-Tinoco et al., 2014) to 2500 $/kW$_e$ – 8000 $/kW$_e$ for solid oxide electrolysis cells [39], and electrolyser lifetime is estimated at 10 000 h [40]. A summary of the cost assumptions is listed in Table 5.

Should a liquid organic hydrogen carrier be used, waste heat from the hydrogenation process can augment the solar heat input to the electrolyser. However, it was excluded from this analysis.

Situated at Upington, this plant would be capable of producing 7684 tonnes of hydrogen per year at a levelized production cost of 4.53 $/kg and consume about 85 Ml fresh water. Equipped with 18 h of thermal energy storage, it won't be producing hydrogen for 838 h per year, assuming a 100% plant availability.

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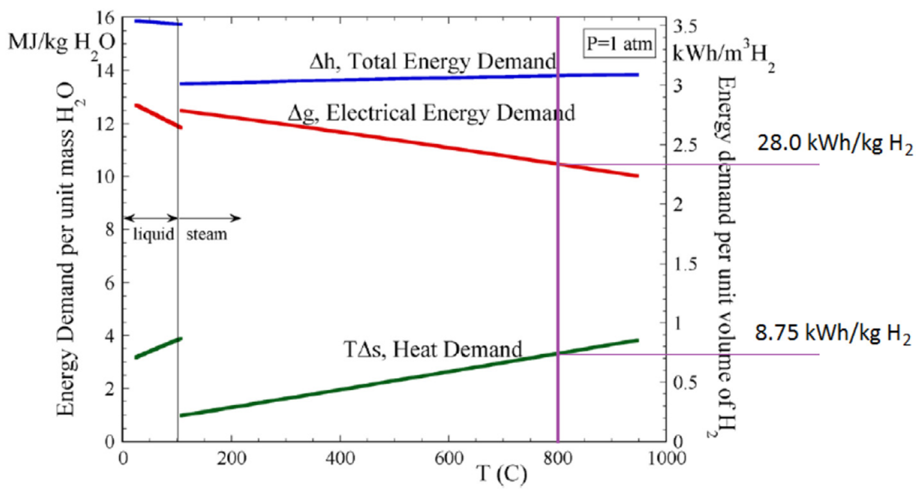

Fig. 6 – Energy requirement of high temperature electrolysis as a function of temperature [13].

Thermochemical water splitting

Several reactions for thermochemical water splitting have been proposed, but none are exploited commercially. The hybrid copper chloride proses requires moderate temperatures (530 °C) well within the capabilities of conventional molten salt plant. Furthermore, a fair amount of development on the hybrid Cu–Cl reactor has been done by the Argonne National Laboratory in the USA, and the University of Ontario in Canada. Cu–Cl plant simulations, using Unisim™ software, have been done at North West University [8] and the Idaho National Laboratory [38], indicating that heat requirement for electricity production and process heat are more or less equal (177.5 MW_t vs 172 MW_t). Kemp's simulation is based on a 350 MW_t nuclear reactor that produces 3880 kg H_2 per hour. A possible configuration to integrate a similar size combined cycle concentrated solar thermal heat and electricity plant with the Cu–Cl cycle is shown in Fig. 7.

It is assumed that the Cu–Cl process is fairly intolerant of interruptions in heat and electricity supply, hence a solar multiple of 4, and 18 h of thermal energy storage were adopted. The plant is situated at Upington in the Northern Cape, and DNI data for the 2016 calendar year from GeoSUN archives was used for this analysis. The solar plant is configured to deliver 4 × 340 MW_t at design conditions (solar noon on 21 March). A common hot salt tank is used to supply heat to the subcritical Rankine cycle (545 °C and 13 MPa) as well as process heat (530 °C) for the Cu–Cl cycle. The hot salt temperature is 565 °C,

Table 5 – Cost assumptions for high temperature steam electrolysis plant.

Item	Cost	Source
Stack	2000 $/kW_e$	Rivera-Tinoco [41]
Balance of plant	570 $/kW_e$	Rivera-Tinoco [41]
Indirect cost	35% of capital cost	Rivera-Tinoco [41]
Operating & maintenance cost	5% of capital cost/year	Rivera-Tinoco [41]
Stack replacement	Every other year	Mehmeti et al. [40]

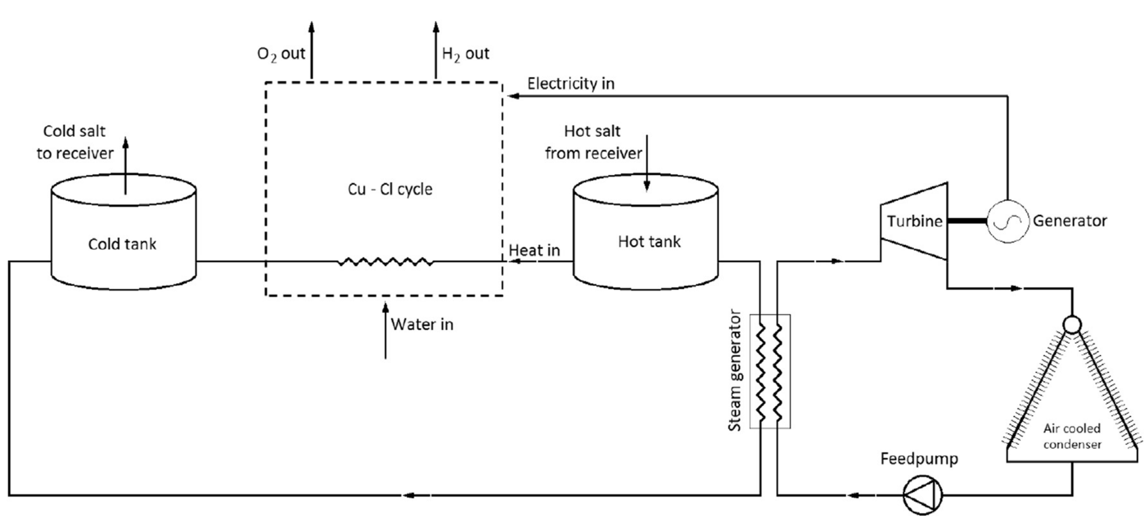

Fig. 7 – Process flow diagram for integration combined cycle solar thermal power and process heat plant with Cu–Cl thermochemical water splitting cycle.

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whilst the cold salt temperature is not allowed to drop below 300 °C. Based on these parameters, the plant can't produce electricity and heat for a total of 580 h per year.

Thermochemical water splitting is an immature technology, and hence considered a risky investment. An interest equal to the prime lending was adopted to reflect the higher risk associated with this technology. Component costs for the solar plant were taken from Mehos et al. [19]; and a plant life of 25 years was assumed. Plant refurbishment, running into 60% of the initial electrolyser cost, was assumed every ten years. Cost assumptions for the solar components are identical to those in Table 3 i.e. it is assumed that the price difference between a sub- and supercritical steam turbine is negligible. Assumptions for the Cu–Cl cycle from [42] are listed in Table 6. The plant is self-sufficient, and does not rely on electricity imports from the grid.

The plant is capable of producing 31 579 tonnes of H_2 per year, at a levelized production cost of 3.77 \$/kg H_2. It would consume about 350 Ml of fresh water per year. Total annual downtime due to insufficient electricity and thermal energy is 621 h. It is assumed that the plant can shut down, given an early warning system (about 18 h) that depends on thermal energy storage levels and local weather predictions. Adding thermal energy storage would be inefficient, as the extra capacity would seldom be utilized.

Summary of results

A brief summary of production cost and volumes for a few existing and near future solar hydrogen technologies are given in Table 7 below.

Data in Table 7 suggests that renewable hydrogen would be three to five times more expensive than hydrogen produced from fossil fuel fired steam/methane reforming. The only exception is carbon lean solar assisted steam/methane reforming. Furthermore, all carbon free technologies came in above the target of 2 \$/kg H_2 at the factory gate [24]. Production cost is lower than that predicted by Boudries [43]. This can in part be explained by the direct normal irradiation at Upington in the Northern Cape Province of South Africa being about 30% higher than that at Adrar in Algeria.

It would appear that the Cu–Cl cycle is potentially the cheapest available option for renewable hydrogen production in South Africa. However, significant development towards commercialization is required for it to become a serious contender. Collaboration between the solar thermal and Canadian nuclear community might expedite the development of the Cu–Cl cycle.

Table 6 – Cost assumptions for Cu–Cl cycle.

Item	Cost
Capital cost	31 500 \$/kg H_2 per hour
Indirect cost	35% of capital cost
Operations and maintenance	5% of capital cost per year
Refurbishment[a]	60% of electrolyser cost (once every ten years)

[a] \$ 15 000 000 for a production volume of 3880 kg H_2/hour.

Sensitivity analysis

The solar plant is responsible for the largest contribution to capital cost; ranging from 56% for the high temperature steam electrolysis plant (process heat only), to 87% for the low temperature alkaline electrolysis plant (concentrating solar power, reverse osmosis and electrolysis). Hence, it is expected that the solar plant will hold a substantial share of the overall hydrogen production cost. Component costs for solar thermal power plant are decreasing, with Sunshot 2020 targets already reached in 2017 (www.solarpaces.org). Revised estimates, based on the projections of Dieckmann et al. [44] are presented in Table 8.

Frequent stack replacements have a significant impact on the cost of high temperature steam electrolysis, assuming that solid oxide electrolyser cells are selected for temperatures above 800 °C. Electrolyser cost should come down with increase in production volumes and improved manufacturing techniques. The immaturity of solid oxide technology is reflected in the vast difference in cost from the literature: 530 \$/kW$_e$ – 1640 \$/kW$_e$ [45]; 1900 \$/kW$_e$ – 2700 \$/kW$_e$ (Rivera-Tinoco et al., 2014) and 4000 \$/kW$_e$ – 6700 \$/kW$_e$ (Schmidt et al., 2018). Schmidt et al. also predicted that electrolyser life will increase to 40 000 h by 2030. An optimistic outlook for high temperature steam electrolysis, based on the average of the lowest predictions of Rivera-Tinoco et al. (2014), James et al. [45] and Schmidt et al. (2018), is presented in Table 9.

Low temperature alkaline water electrolysis is a mature technology, with limited potential for further cost reduction.

Table 7 – Summary of renewable hydrogen production options for South Africa.

Technology	Production volume [ton/year]	Production cost [\$/kg]	Comment
Solar steam/methane reforming	126 800	1.50	Existing technology Carbon lean
Low temperature electrolysis (wind & PV)	16 800*	4.42	Existing technology * At installed capacity
Low temperature electrolysis (CSP)	21 300	4.69	Existing technology Single plant
High Temperature Steam Electrolysis (CSP & PV)	7700	4.53	Future technology Single plant
Cu–Cl cycle (CSP)	31 600	3.77	Future technology Single plant

Table 8 – CSP component cost estimates for 2020 and 2025.

	2020 (Mehos et al.)	2025 (Dieckmann et al.)
Land[a]	0.25 \$/m^2[b]	1 \$/m^2[b]
Site preparation[b]	20 \$/m^2[b]	5.5 \$/m^2[b]
Heliostats	120 \$/m^2[b]	97.5 \$/m^2[b]
Tower & receiver[c]	170 \$/kW_t	144 \$/kW_t
Thermal energy storage	22 \$/kWh_t	22 \$/kW_t
Power block[d]	1050 \$/kW_e	1100 \$/kW_e

Notes.
[a] Depends on country and region, but has an insignificant effect of LCOE.
[b] Dieckmann et al. includes it in heliostat cost (but cost breakdown is provided).
[c] Dieckmann et al. gave separate cost estimates for tower (\$/m) and receiver (\$/kW). The 144 \$/kW_t is based on [19] estimate and a 20% cost reduction suggested by Dieckmann et al.
[d] Dieckmann et al. specifies dry cooling, but Mehos et al. isn't clear on this point.

Table 9 – Optimistic cost outlook for high temperature steam electrolysis plant.

	Current	2025	Source
Stack	2000 \$/kW_e	1000 \$/kW_e	Average low
Balance of plant	570 \$/kW_e	570 \$/kW_e	Average low
Indirect cost	900 \$/kW_e	550 \$/kW_e	Average low
Stack replacement	Two year intervals	Five year intervals	Schmidt et al.

A stable outlook was assumed, but as it is also the configuration with the largest solar contribution to capital cost, some cost reduction is expected.

Thermochemical water splitting is an emerging technology, and cost estimates by Kromer et al. [42] are based upon earlier work of Lewis et al. [46]. Kromer et al. predicted that the total installed capital cost of the Cu–Cl plant will drop by 15% in the decade from 2015 to 2025.

Applying Dieckman et al.'s [44] component costs to the solar plant, and the anticipated hydrogen production cost reductions listed in Table 9 and elsewhere, gave the projected hydrogen production costs listed in Table 10. One should bear in mind that the alkaline water electrolysis technology is available right now, whilst commercial applications of the other two technologies, although potentially cheaper, may not be realized by 2025. Furthermore, processing, storage and transport cost of 1.75 \$/kg H_2 [9] is excluded in Table 9. Hence, the short term outlook for solar hydrogen in South Africa falls short of the United States Department of Energy's target of 2 \$/kg H_2. It is also not price competitive with methane/steam reforming, currently available at 1.39 \$/kg H_2 [9].

Interest rates in Europe averaged below 2% over the two decades from 1998 to 2018 (https://tradingeconomics.com/euro-area/interest-rate), that are substantially lower than South African interest rates. The same risk premium as before was assumed, and hence the project is hypothetically financed by European banks at an interest rate of 5.75% for the high temperature steam electrolysis and Cu–Cl plants. The alkaline water electrolysis plant carries less risk, and it is assumed that it can be financed at 3.5%. Furthermore, the loan term is extended to 30 years. Under these assumptions with current cost estimates, the production cost of hydrogen is reduced to 2.14 \$/kg for the alkaline water electrolysis plant, 3.41 \$/kg for the high temperature steam electrolysis plant, and 2.14 \$/kg for the Cu–Cl plant. It is clear that financial parameters are at least as important as technical progress in reducing hydrogen production costs.

Table 10 – Current and future hydrogen production costs in South Africa.

	Current	2025
Alkaline water electrolysis	4.69 \$/kg H_2	3.82 \$/kg H_2
High temperature electrolysis	4.53 \$/kg H_2	3.27 \$/kg H_2
Cu–Cl cycle	3.77 \$/kg H_2	3.17 \$/kg H_2

Conclusion

South Africa has an abundant solar resource, and the country is in a good position to take up carbon free hydrogen production for both the domestic and export markets. Photovoltaic and wind electricity have overtaken coal as the cheapest energy source in the country. However, the intermittent nature of both sources, means that hydrogen production volumes would be limited, especially after sun-down. This assumes that grid scale battery storage wouldn't be realized in the near future. It does offer hydrogen at an attractive price of 4.42 \$/kg H_2, that is still not comparable with steam/methane reforming, especially if carbon taxes/carbon capture becomes compulsory for the reforming process.

A dedicated solar thermal power plant and alkaline electrolyser was identified as the technology having the highest production cost at 4.69 to 3.82 \$/kg H_2. Since all technologies are mature, scope for future cost reductions may be somewhat limited. On the positive side, this technology is ready for immediate implementation. Furthermore, it relies on desalinated sea water as feedstock, and won't stress South Africa's scarce freshwater resources.

High temperature steam electrolysis both reduce the energy requirements of hydrogen production plant, the high cost of the associated solar plant means that it can't compete on price against more established technologies. High temperature steam electrolysis is an emerging technology that has been demonstrated on laboratory scale, and plant component cost is expected to come down as production volumes and manufacturing techniques improve. Optimistic estimates [45] suggest that electrolyser cost may reduce by an order of magnitude, whilst stack replacement intervals can increase from 10 000 h to more than 40 000 h. Similarly, particle receivers are also tested on experimental scale [36], and significant cost reductions are expected. Development of a high temperature (>850 °C) heat exchanger remains a significant challenge for this technology. Electricity tariffs remain a significant cost driver for all electrolyser plants. Hydrogen production cost is estimated to vary between 4.53 and 3.27 \$/kg H_2. This is reasonably close to the numbers of James et al. [45] of 4.95–3.83 \$/kg H_2.

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Thermochemical water splitting by the Cu–Cl cycle is an excellent fit to current molten salt solar thermal technology. It requires a lower electricity input than water or steam electrolysis plant, and a moderate temperature (~550 °C) heat source. The balance between the Cu–Cl cycle's heat and electricity inputs is such that a single concentrated solar plant can satisfy both. This plant can potentially operate independent of the electricity network. Although all individual processes have been demonstrated on laboratory scale [46], the complete cycle has not. Hydrogen production cost is attractive amongst cycles involving concentrated solar energy, at 3.77 to 3.17 $/kg H_2. This is close to the hydrogen production cost using a nuclear reactor as heat and electricity source suggested by Lewis (3.1 $/kg H_2), but significant below that of Kromer et al. [42] for solar hydrogen production (5.39 $/kg H_2) using electricity supply from the grid.

One of the main assumptions was that power from renewable energy sources is available at cost directly from the supplier. The reality is that the South African state owned utility ESKOM is under the South African law the sole buyer and seller of renewable energy, and hydrogen plant relying on grid supplied electricity will probably have to pay standard ESKOM tariffs (ESKOM, 2018). These tariffs vary with season and time of use during the day; a weighted average is about 0.09 $/kWh$_e$ (including a network charge), that is almost double the generation cost of wind or photovoltaic power in South Africa.

As an emerging market, the South African economy is fairly volatile, and the country has a low international credit rating. Consequently, local interest rates are high in comparison with developed countries. Improving the country's economic stability has a potential impact comparable with anticipated technology advances on the production cost of hydrogen.

Although South Africa is well positioned to become a major player in solar hydrogen production, solar technologies can't compete on price against conventional steam/methane reforming. Environmental legislation, rather than economics will probably be the industry driver for the transition to a carbon free hydrogen economy. Most countries in the world are committed to climate change mitigation, that may expedite the transition to hydrogen as energy carrier, especially in the transport sector.

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