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LCOE Reduction Potential of Parabolic Trough and Solar Tower Technology in G20 Countries until 2030

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Abstract. This paper summarizes the methodology and results of a study performed in 2018. The aim was to calculate and compare current (2018) and future (2030) LCOE for CSP plants in all G20 countries. Individual DNI resources for the best region in each country, as well as an alternate location closer to demand for Australia and Saudi Arabia were used as basis for the annual performance calculations. Country-specific installed costs were developed for 2018 and 2030, with local content shares and international equipment cost assumptions varied by price indices to complete the picture. Sensitivity of the results to both the relative price index and DNI are also shown.

INTRODUCTION

Reliable and timely cost data for electricity generation technologies is essential if decision makers are to robustly assess the role of different energy technologies in the future energy mix in order for countries to reach their economic, environmental and social development goals. With an installed capacity of about 5 GW, Concentrated Solar Power (CSP) has the lowest deployment of all the commercially available renewable power generation technologies. Some cost reduction progress has been made in recent years, as developers gain more experience and the supply chains have broadened and become more competitive. These lower electricity generation costs in recent years have been driven by both lower total installed costs, performance improvements and a trend towards installation in higher DNI areas. However, the limited number of plants that have been designed and installed in just a handful of small-scale markets, mean that reliable and transparent cost data for CSP remains difficult to obtain The International Renewable Energy Agency (IRENA) has been working to fill this information gap on historical cost data since 2011; and DLR and IRENA collaborated in 2016 to undertake an analysis of future cost reduction potentials for CSP in 2016 to help inform policy makers, climate and energy modelers and industry stakeholders. The collaboration led to the comprehensive study on cost reduction potential for parabolic trough and solar tower technology published in 2016 that focused on the cost reduction potential for a global benchmark plant, with a sensitivity analysis around certain important cost drivers [1], [2].

This publication is both a follow-up of the study performed in 2016 and an expansion of the analysis to include detailed cost and performance analysis for each G20 country with adequate DNI. The analysis is based on the same methodology as the previous analysis, expanded to cover the challenges of identifying CSP plant costs in individual countries with a mix of local and imported content and at different stages of both economic development and experience with CSP. The analysis uses as a starting point the latest CSP cost data from the IRENA Renewable Cost

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Database, as well as cost information gleaned from the most recent developments on the CSP market. The methodology therefore yields country-specific plant performance data and total installed costs that are combined with operations and maintenance cost assumptions to yield the levelized cost of electricity (LCOE) for each country in 2018 and 2030.

TECHNOLOGY DESCRIPTION: PARABOLIC TROUGH AND SOLAR TOWER PLANTS TODAY AND IN 2030

This study is limited to the two most widely deployed CSP technologies, parabolic troughs and tower systems with central receiver. For each technology, current state of the art (reference) and future plants are the basis for the cost assessments. In order to simplify the analysis required, some assumptions are made around the overall optimal parameters of plant design (e.g., size, technology employed, storage capacity, etc.), but the lower-level plant specifications are then optimized through simulation for each location based on DNI (e.g., solar field size).

Parabolic Trough Technology

Today most solar thermal power plants with parabolic trough collectors are using an eutectic mixture of biphenyl/diphenyl oxide (BP/DPO) as heat transfer medium in the solar field circuit. Due to the maximum operating temperature of BP/DPO of about 400°C, the live steam temperature of these plants is limited to about 385°C, resulting in a thermal efficiency of up to around 39% for the power block (depending on condenser type and ambient conditions).

Figure 1 shows a scheme of such a plant, highlighting that three different fluids are used: BP/DPO in the solar field cycle, water/steam in the power block cycle and molten salt in the thermal storage. Each fluid has specific advantages for its field of application but Fig. 1 also shows that several heat exchangers are necessary. This increases the total investment and reduces the maximum temperature of the live steam at turbine entrance due to losses.

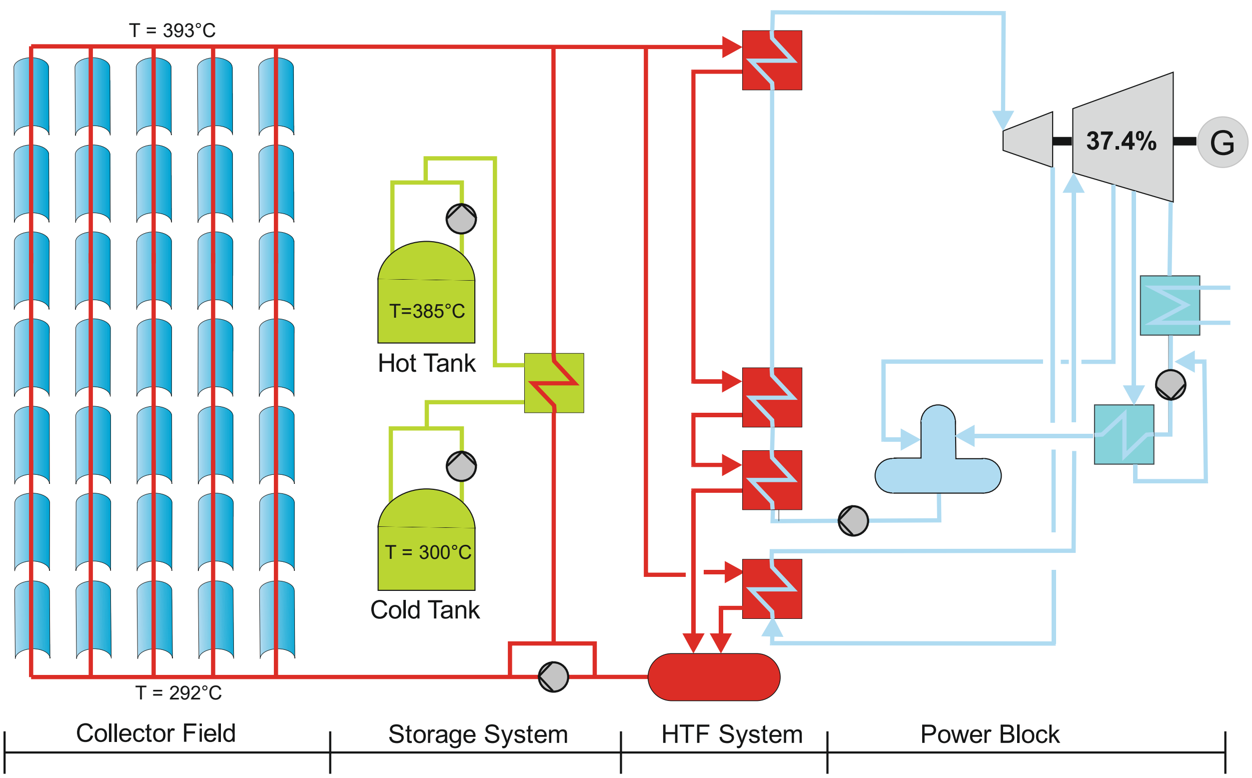

FIGURE 1. Reference trough system 2018: Solar thermal power plant using parabolic trough technology with BP/DPO as heat transfer medium and molten salt as storage medium (red: BP/DPO, blue: water/steam, green: molten salt).

Currently, research and development activities in the trough field are focused on increasing the live steam temperature by replacing the BP/DPO with another fluid. The investigated candidates are silicone oil, molten salt and water/steam.

Using molten salt instead of BP/DPO as heat transfer and storage medium increases the usable temperature level to 500°C or more, although the steam temperature at turbine inlet is typically about 10-20°C lower than the maximum HTF temperature. The increased steam inlet temperature allowed by the use of molten salts can increase the thermal efficiency of the power block from around 39% with BP/DPO to up to 43%. In addition, the temperature difference between both molten salt storage tanks is increased from approximately 85°C to 230°C which means that the storage volume needed can be cut by more than 60% for the same storage energetic capacity.

Figure 2 shows the simplified cycle for parabolic trough plants using molten salt as heat transfer and storage medium. In addition to not requiring the heat exchanger between salt and BP/DPO, a plant using molten salts as HTF also doesn't need storage tanks and auxiliaries for the BP/DPO, which was not shown in the simplified plant schematic in Figure 1.

There is, however, a drawback, as today's low-cost molten salt mixtures that are suitable for such high temperature applications show high freezing temperatures of 142°C (HITEC® Salt: $NaNO_3$, $NaNO_2$, KNO_3) or even 222°C (Solar Salt: $NaNO_3$ and KNO_3), which is the main reason that they are not yet state-of-the-art for parabolic trough solar power plants. Intensive research is going on and these plants are the most promising candidates for the next generation parabolic trough plants.

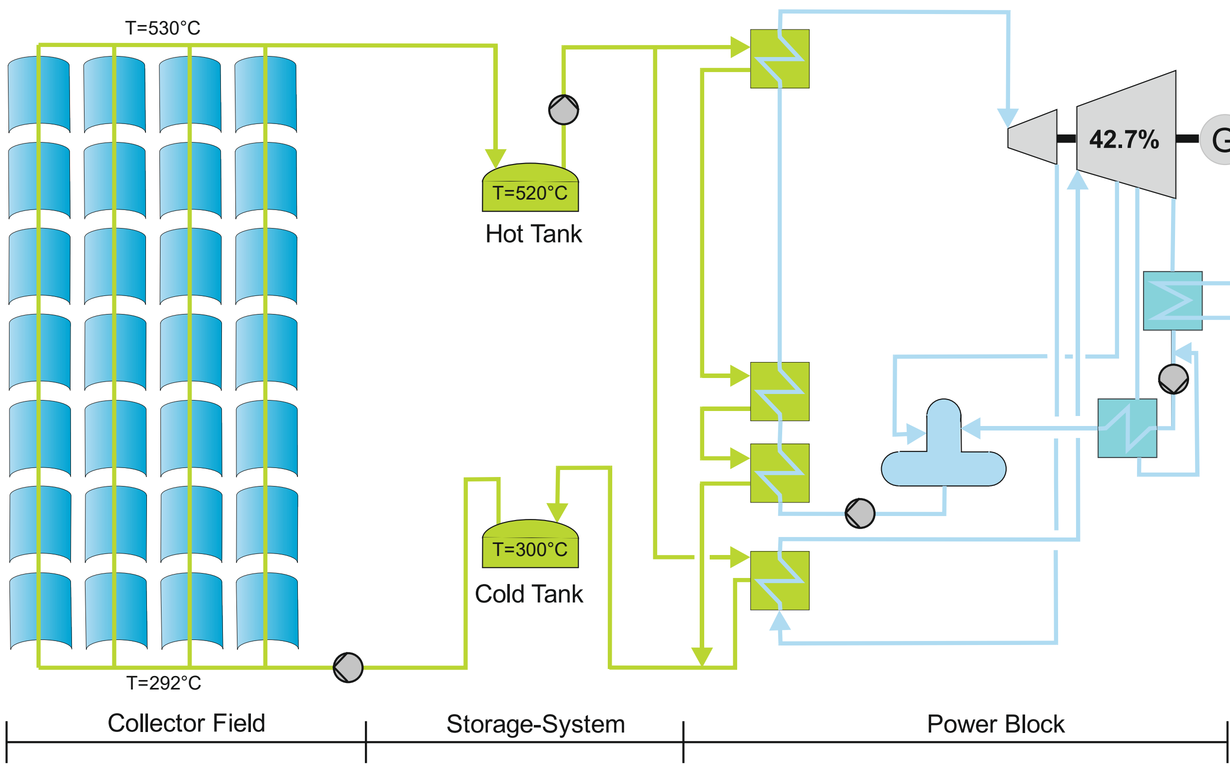

FIGURE 2. Future trough system 2030: Solar thermal power plant using parabolic trough technology with molten salt as heat transfer as well as storage medium (blue: water/steam, green: molten salt).

In addition to the switch-over to molten salt as the HTF, it is expected that future parabolic trough collectors will have larger aperture widths, in the range of approx. 10 m+ compared to a more standard 7.5 m in 2018. This leads to a smaller number of collectors for the same aperture area, which is also shown in Fig. 2. In addition, these large aperture collectors need fewer drives, connecting elements between single units, and control units per m² compared to collectors with smaller aperture. These factors all contribute to reducing costs per m². They also result in higher concentrations (aperture area / receiver area), which helps to limit the heat loss increase caused by higher HTF and absorber temperatures.

Solar Tower Technology

Today solar tower power plants with large thermal storage capacities are primarily using molten salt as the heat transfer and storage medium. In contrast to parabolic trough plants, the receiver and the associated piping may be easily constructed in a manner that daily filling and draining can be used to avoid the risk of freezing in these parts of the plant, thereby also reducing the power needed for heating overnight. Therefore this technology can be considered state-of-the art and the plants are using only two cycles as shown in Fig. 3.

Molten salt as HTF is stable up to temperatures of 560 - 600°C compared to 400°C for BP/DPO which is used for trough technology in 2018. Since the lower temperature limit is defined by the freezing point of storage material (Solar Salt) for both cases, the increased maximum temperature means the usable temperature difference for the storage is increased by a factor of about 2.5 Higher HTF temperatures enable higher turbine efficiencies, since according to Carnot's rule, the maximum efficiency of any heat engine depends on the temperature difference between the hot and the cold reservoir. Here the cold reservoir is the ambient temperature since the condenser cooling is done with ambient air. Although real turbines do not reach Carnot's efficiency due to technical losses, the general impact of inlet temperature on efficiency is still valid. Therefore, a higher turbine inlet temperature to the turbine boosts the turbine's efficiency.

The differences between the tower reference plant 2018 and the future plant 2030 are limited to slight temperature increases and, as consequence, minor efficiency gains. For both cases the power block cycle efficiency is around 44%. There are of course other parameters which also have an impact on turbine efficiency (size, quality, shape of the blades, etc.) but these parameters have assumed to be identical for the cycles considered in this study.

There are currently research efforts for new heat transfer media (solid particles, liquid metals) [3] and cycles (e.g. supercritical CO_2) [4] but these new technologies will most probably not be available for commercial projects in 2030, at least not at any scale. This would be consistent with the lead times experienced from the development of innovative new solutions and their commercialization during the past 12 years in this sector, but faster development might be possible in the right circumstances.

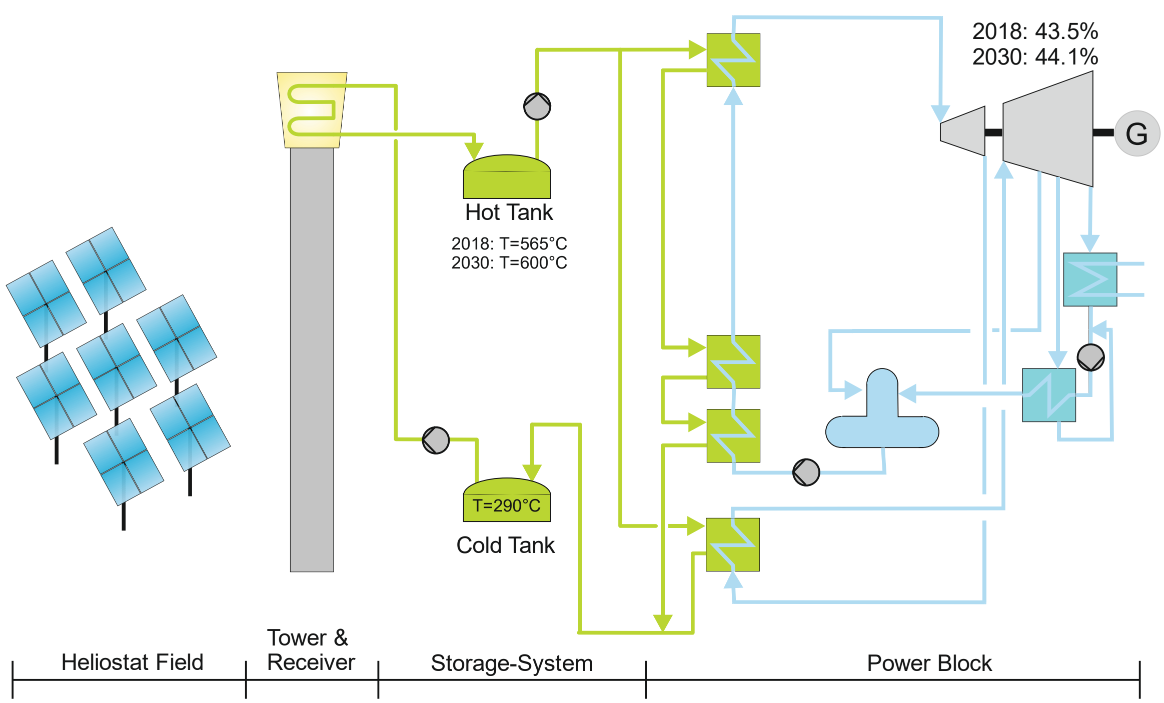

FIGURE 3. Tower system 2018 and 2030: Solar thermal power plant using tower technology with molten salt as heat transfer and storage medium (blue: water/steam, green: molten salt).

METHODOLOGY

The approach and methodology used in this study can be summarized as follows:

1. Define reference state-of-the-art (2018) systems for trough and tower technology.
2. Screen for expected technological development / innovations and define future (2030) CSP systems.
3. Find representative sites for CSP in all G20 countries and determine meteorological datasets representing a typical year with hourly resolution.
4. Find the solar field size leading to the lowest LCOE for each site and technology.
5. Define current and future component cost benchmarks based on today's cost structures and incorporating technological innovations to 2030 and supply chain improvements as the industry scales.
6. Define the local content for all cost components (fraction of goods and services which might be procured in the country itself) and calculate local costs for all G20 countries based on a published cost index.
7. Perform yield analysis and calculate LCOE for 2018 and 2030 for each country using individual costs and individual yield. The same interest rate of 7.5% was used for all countries.

This study builds on the DLR and IRENA collaboration for CSP from 2016 [2] and utilises a similar methodology that is adapted to need to develop country-specific installed costs and plant performance. As described in [2] all cost estimations are based on the assumption that the total CSP capacity of about 40 GW in 2030 [2]. If less capacity is added, learning effects might be lower, resulting in smaller cost reductions, conversely, if deployment is higher costs may be materially lower than presented here.

Table 1 provides an overview of the key CSP plant technology characteristics that are used for parabolic trough and solar tower CSP plants in 2018 and 2030. This is not an attempt to model the optimal country-specific plant configuration, in order to reduce the computational analysis required to cover each G20 country with suitable DNI for CSP plants. Country-level simulations for specific locations could yield some differences, notably for plant size and storage capacity, but this project-specific analysis is beyond the scope of the DLR and IRENA collaboration.

TABLE 1. Overview of the key dimensioning parameters of the reference and future plants

		Parabolic Trough		**Solar Tower**	
Design Parameters	**Unit**	**2018**	**2030**	**2018**	**2030**
Solar collector / heliostat		Ultimate Trough®	10m Future Trough	Heliostat based on the Sanlucar 120 type of Abengoa	Future Heliostat
Heat transfer fluid (HTF)		BP/DPO	Ternary Salt[1)]	Solar Salt[2)]	Solar Salt
Storage medium		Solar Salt	Ternary Salt	Solar Salt	Solar Salt
Maximum HTF temperature	[°C]	393	530	565	600
Thermal energy storage capacity (full load hours)	[h]	7	7	10	10
Gross electrical output	[MW]	150	150	150	150

1) Ternary salt mixtures offer the advantage of reduced solidification temperature. One commercial example is Hitec, composed of 7 wt% sodium nitrate ($NaNO_3$), 40 wt% sodium nitrite ($NaNO_2$) and 53 wt% potassium nitrate (KNO_3).
2) Solar Salt: Mixture of 60 wt% sodium nitrate ($NaNO_3$) and 40 wt% potassium nitrate (KNO_3)

Software Tool and Operating Strategy

The annual yield analyses for this study were generated with greenius, a software tool which is freely available [5]. The tool is optimised for fast calculations of annual energy yields in CSP plants, and hence, the models are based on heat flows. Relevant CSP plant technologies (PTC and ST), with corresponding heat-transfer fluids are implemented in greenius and their energy yields can be compared. Input parameters, such as solar field size, storage capacity and power block nominal power, can be varied easily and in that manner their influence on the electricity yield can be analysed.

The current version of greenius contains lookup tables for solar tower field and receiver performance. These lookup tables are valid for a wide range of solar field sizes and latitudes since optimal field layout depends heavily on these two parameters. The lookup tables have been generated using the code HFLCAL [6] (a program for design and optimization of heliostat fields of central receiver systems) and represent optimized layouts for a wide range of sites (latitudes). Although greenius is capable of doing economic calculations, the economic modelling was done separately to allow changing economic parameters quickly without recalculation of the technical part relating to the plant yield.

Power block performance is modelled using a performance map. The same dimensionless performance map is used for all plants investigated in this study. Only the nominal gross efficiency and the nominal power block input are varied for the individual technologies and years.

In this study a simplified solar-only operation strategy is assumed in order to calculate yield, it follows the following criteria:

- The solar field and receiver are operated whenever heat production is possible.
- During hours when the solar field delivers sufficient heat, this heat is used to produce steam and run the steam turbine to produce electricity.
- All plants are simulated with thermal storage (7 hours for all parabolic trough systems and 10 hours for all solar tower systems).
- In case the solar field delivers more heat than the steam turbine can accept, the excess heat is used to charge the thermal storage.
- During those hours when the solar field delivers less heat as needed for full load operation of the steam turbine, heat from the thermal storage is used to operate the steam turbine at full load. This is done until the storage is empty and afterwards the turbine is turned off.

Solar Resource for Individual Countries

The global solar atlas (http://globalsolaratlas.info) has been used to identify those regions with high DNI resources within each country. Afterwards the software METEONORM Version 7.1 [7] has been used to select meteorological stations or cities within this region and to generate a typical meteorological year for this site for the yield simulation. The following table shows the results of this procedure. From the global solar atlas a rough estimate of the annual sum of DNI range was gained while the datasets from METEONORM deliver distinct values which fit quite well with the estimate from solar atlas. The highest deviation between both sources was found for China and Mexico (+8.7% and -10.7%).

During the project execution one additional site was added for Saudi Arabia since Tabuk might be too far away from the major consumer centers. In the same way two sites for Australia were chosen instead of Alice Springs, which offers the highest DNI resource but may be too isolated to build a large CSP plant to deliver public electricity supply. Sites in Morocco and UAE were also added since these countries are currently implementing several CSP plants and this helps with benchmarking the performance of new markets.

Table 2 shows a wide range of DNI resources from 1033 kWh/m² up to 2864 kWh/m². Under these conditions the solar field size and LCOE will differ significantly. Orange cells represent countries with annual DNI sums below 1200 kWh/m² which may be not suitable for CSP since such low DNI would lead to very high LCOE and thus prohibit the utilization of this technology due to economic reasons. However, Germany is included as one example in order to show the results in comparison to those countries with high DNI.

TABLE 2. Overview of sites, latitudes and their DNI resource

Country	Annual sum of DNI from global solar atlas	Region	Latitude	Site	Annual sum of DNI from METEONORM
	kWh/m²			from METEONORM	kWh/m²
Argentinia	1900 - 2100	South west of Buenos Aires	-36.6°N	Santa Rosa Airp.	1815
Australia	2700 - 2900	Central Australia	-23.8°N	Alice Springs	2571
Australia		North Australia	-21.10°N	Whundo	2627
Australia		South Australia	-32.82°N	Whyalla	2295
Brazil	2000 - 2200	Bahia	-13.5°N	Correntina	2004
Canada	1700 - 1900	southern part of Saskatchewan	50.2°N	Regina	1856
China	1800 - 1900	Inner Mongolia	41.6°N	Haliut	2082
France	1800 - 1900	Cote'd Azur	43.1°N	Toulon	1970
Germany	1100 - 1200	South west, Freiburg	47.7°N	Konstanz	1077
India	1800 - 2000	North west, Rajasthan	26.3°N	Jodhpur	1906
Indonesia	1000 - 1300	most regions but up to 2000 in Timor	-10.2°N	Kupang	1541
Italy	1800 - 1900	Sicilia	37.1°N	Gela	1963
Japan	1100 - 1300	Region Tokyo	36.1°N	Tateno	1103
Mexico	2700 - 2800	Chihuahua, close to New Mexico	31.6°N	Ciudad Juarez	2438
Russia	1350 - 1450	Close to Caspian Sea	46.3°N	Astrahan	1487
Saudia Arabia	2600 - 2800	North west, Tabuk	28.4°N	Tabuk	2867
Saudia Arabia		Region Medinah	25.6°N	Chaibar	2529
South Africa	2900 - 3000	North west, Northern Cape	-28.4°N	Upington	2864
South Korea	1200 - 1300	whole country	37.3°N	Wonju	1033
Turkey	1800 - 2100	Southern part, Icel	38.0°N	Konya	2018
United Kingdom	1000 - 1000	Southern Coast	50.8°N	Brighton	1035
United States	2700 - 2900	California	34.9°N	Barstow	2660
European Union	2000 - 2200	Andalucia, Spain	37.2°N	Granada	2039
Morocco	2400 - 2500	Ouarzazate	30.95°N	Ouarzazate	2558
United Arab Emirates	1900 - 2000	Dubai	24.75°N	MBR Solar Park	1759

Solar Field Dimensioning for Individual Sites

For a fixed power block size, a fixed thermal storage capacity and fixed component costs one may find a solar field aperture area leading to minimum LCOE [8]. Experience from many solar field optimizations and from preliminary studies done by the authors show that the minimum LCOE typically occurs for oversized solar fields which will produce more heat than the power block and the storage can utilize, at least during some time periods throughout the year. This excess thermal energy ("dumping") could in theory be produced by the solar field, but is not, as certain collectors or heliostats are defocused to avoid it. The model calculates the dumping fraction from the annual dumped heat divided by the annual thermal output the solar field could deliver (including the dumping).

The minimum LCOE typically occurs at around 10% of dumped thermal energy for parabolic trough plants and around 3% of dumped thermal energy for solar tower plants. The exact value depends on specific costs of individual parts of the plant and their ratio among each other. But this dependency is not very strong, so that the above mentioned dumping rates may be used as a good compromise even when the specific costs are not known exactly. These dumping rates of 10% for trough and 3% for tower plants are not physical constants but rather a rule of thumb gained.

Utilizing these assumptions in the techno-economic optimization reduces substantially the number of simulation runs and length of time required to identify a site-specific plant configuration that minimizes LCOE, especially when one of the economic parameters is modified. This was crucial to ensuring that this project could cover all of the G20 countries with adequate DNI for a CSP plant. Therefore all CSP plants are designed individually for each site for a certain dumping rate (10% for parabolic trough plants and 3% for solar tower plants) to find their individual solar field aperture and performance data.

In total, 84 different plant designs have been assessed. Four G20 countries were a-priori identified as not suitable for CSP applications. Those are Germany, Great Britain, Japan and South Korea. However, Germany has been included for representation of non-CSP countries and as reference due to its cost index of 100.

Estimation of Country-Specific Costs and Local Content

CSP plants are large units which are typically built by international EPC companies and consortia. Their supply chains rely on both international and local partners. The latter ones change from project to project and provide more general services like civil engineering or workforce during construction phase, but also many basic materials required (e.g., cement, rebar, etc.). Currently, with the relatively small CSP market, there are few international suppliers that can provide expert knowledge and key CSP-specific components (e.g., collectors, heliostats, etc.) in many cases, limiting competition and economies of scale.

To calculate today's reference cost for PTC and solar towers, the investment costs for each of the main components of the CSP plants are split into sub-component costs comprising both material and labour costs. Table 3 gives an example of this analysis for the 'parabolic trough field' only. The 'Material + Labour' costs in the second column are estimated based on OECD average price levels (price index = 100), this then allows costs to be varied based on the local content shares using a country-relative price index. Table 3 is valid for all countries; specific costs for individual countries are calculated by multiplying the local cost (column 7) and the individual price index.

To ensure a robust estimation of the local content levels, those sub-component costs are further subdivided into material and labour share. The latter step is not obligatory for the used methodology, but the distinction between material and labour facilitates the estimation of local shares, since higher shares of labour can usually be sourced locally, while some key materials are only available from international suppliers and will need to be imported at market rates. The estimation of local shares for material and labour share of each sub-component is a key factor for the comparison of international investment costs and is based on experience with recent projects, a number of publications [12 – 18] and the expert judgement of the authors. For this study local shares are assumed the same for all countries (Table 4). Furthermore local costs for transport, insurance, custom clearance, etc. are not considered in detail but are assumed to be included in the price index and international costs. Better country-specific data at a component and sub-component level would assist with this analysis, but it is rarely available.

TABLE 3. Example of the breakdown of material and labour costs into local and international cost for the field component of a parabolic trough plant (2018). All costs given in this table are for price index = 100

Parabolic Trough Field	**Material + Labour [$/m²]**	**Share Material [%]**	**Share Labour [%]**	Local content Material [%]	Local content Labour [%]	Local Cost [$/m²]	International Cost [$/m²]
SF - Site Preparation	25	40%	60%	90%	90%	22.41	2.49
SF - Collector Structure	58	50%	50%	80%	80%	46.40	11.60
SF - Pylons & Foundations	19	40%	60%	90%	80%	15.96	3.04
SF - Mirrors	15	100%	0%	0%		0.00	15.00
SF - Receivers	25	100%	0%	0%		0.00	25.00
SF - Drives	6	100%	0%	0%		0.00	6.00
SF - Electrical	4	90%	10%	80%	80%	3.32	0.83
SF - HTF (only Fluid)	21	100%	0%	0%		0.00	20.50
SF - HTF System (Rest)	31	75%	25%	30%	80%	13.18	17.83
Total PT Field	**203.6**					**101.27**	**102.29**
						49.7%	50.3%

The estimated local costs for a certain country are then calculated by scaling the local cost component of the OECD reference average cost up or down based on the individual country price index value (see next paragraph). The same approach is used for operation and maintenance costs which are dominated by the labour share. The long-term operation of these plants allows the formation of local O&M teams leading to high local content of the labour share. It is important to note that sub components with low local content are not necessarily sourced from another country than the project site. The definition of "local" respectively "international" rather refers to the expected market structure of the sourced goods and services. This has two important implications, in countries with typically low costs, a lack of competition for certain sub-components may mean that costs are closer to the OECD benchmark value used, conversely, in high-cost markets (e.g., a country-specific price index above 100) a low local content value may imply that competition from international suppliers will keep costs down.

TABLE 4. Specific costs (price index =100) and estimated local fractions used for the major components

	2018		2030	
	Specific cost	**Local fraction**	**Specific cost**	**Local fraction**
Parabolic trough plant				
Solar field	205.6 \$/m²	49.3%	166.2 \$/m²	53.3%
Thermal storage	40 \$/kWh$_{th}$	21.9%	26 \$/kWh$_{th}$	31.9%
Power block	920 \$/kW$_e$	26.5%	830 \$/kW$_e$	26.6%
O&M	1.5 % of direct cost	82.0%	1.5 % of direct cost	82.0%
Solar tower plant				
Heliostat field	131 \$/m²	47.5%	99.7 \$/m²	44.6%
Tower	90000 \$/m	80.0%	72000 \$/m	80.0%
Receiver	125 \$/kW$_{th}$	34.0%	100 \$/kW$_{th}$	34.0%
Thermal storage	26.4 \$/kWh$_{th}$	34.7%	22 \$/kW$_{th}$	31.7%
Power block	970 \$/kW$_e$	26.5%	837 \$/kW$_e$	26.6%
O&M	1.5 % of direct cost	82.0%	1.5 % of direct cost	82.0%

Price Index

This index has been taken from OECD data [9]. Values for Saudi Arabia and Argentina were not available in this data base at the time of access (May 28, 2018). Therefore they have been calculated by the authors from the purchasing power parity and exchange rates between the local currency and the US-\$. Both are available for 2016 from OECD data bases [10] [11]. The index is a consumer price index while this study is rather dealing with industrial systems but it was the best freely available index comprising almost all countries and with numbers comparing all countries on a common basis. Figure 4 shows all values used in this study.

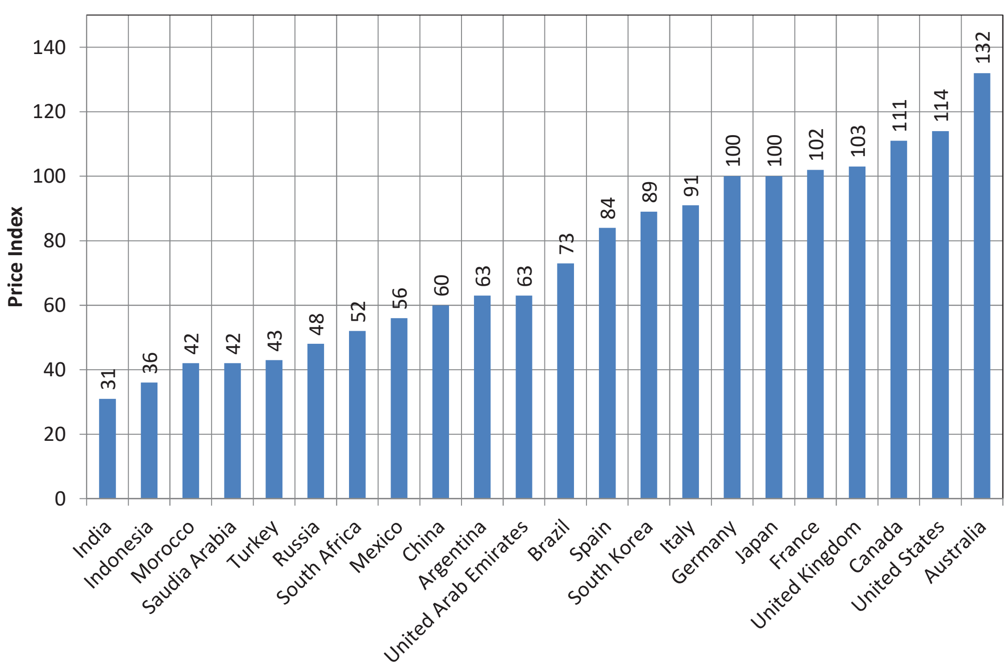

FIGURE 4. Price index of all countries assessed in this study (OECD average: 100).

Cost Analysis

The OECD average total capital expenditure (CAPEX) for the reference plants in 2018 are estimated at USD 628 Mio. (USD 4186/kW) for the parabolic trough and USD 791 Mio. (USD 5257/kW) for the solar tower technology (assuming the system design for Morocco and using a price index of 100, Morocco has been chosen here due to current CSP projects and the DNI resource of 2558 kWh/m²). The distribution of the CAPEX on the plant components and their estimated evolution until 2030 can be seen in Fig. 5 and Fig. 6.

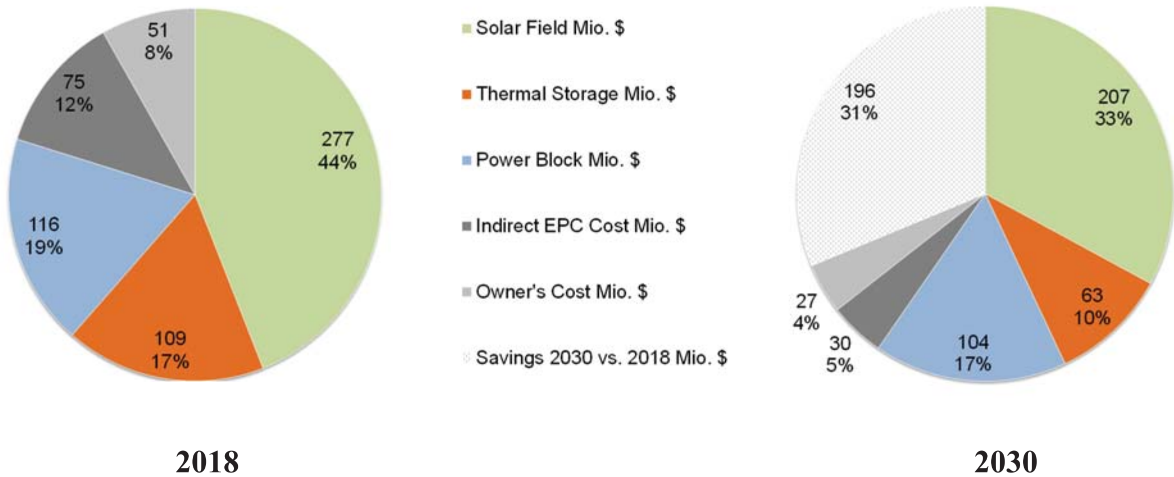

FIGURE 5. Comparison of CAPEX structure in 2018 and 2030 for 150MW parabolic trough power plant at OECD average prices (system configuration for Morocco)

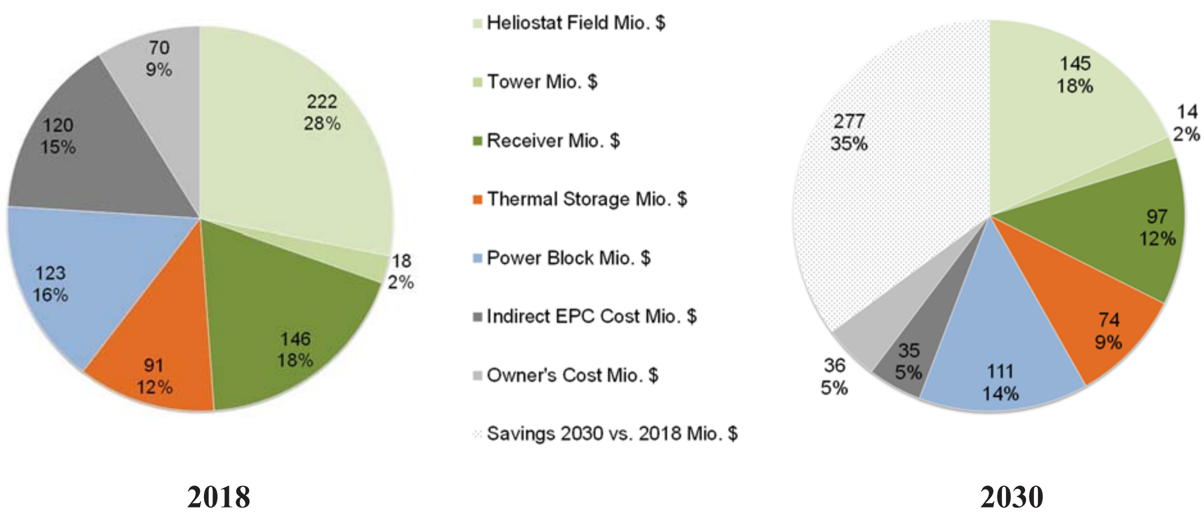

FIGURE 6. Comparison of CAPEX structure in 2018 and 2030 for 150MW solar tower power plant at OECD average prices (system configuration for Morocco)

For 2018, the CAPEX distribution for trough and tower differ in important ways. Storage costs for the solar tower are lower in absolute and percentage terms, because the molten salt receiver of the solar tower allows maximum HTF temperatures of 565°C compared to 393°C for the trough. This results in a temperature differential between the cold and the hot storage tank is more than twice as large then the parabolic trough. This reduces the storage volume for the molten salts by more than half for the same amount of thermal energy stored. In 2018, the indirect costs of towers are estimated to be higher than for troughs because of additional contingency margins resulting from the lower experience in developing these projects. In 2030, these differences for storage and indirect costs narrow as troughs reach almost as high temperatures as towers, while sufficient experience in developing solar towers reduces the contingency part in indirect costs. The total installed cost of parabolic trough plants in 2030 are estimated to be around 31% lower than in 2018 as the industry scales, supply chains become more competitive and greater developer experience reduces margins. Given that the deployment of solar towers is relatively modest today, the cost reduction potential is somewhat higher, with total installed costs in 2030 estimated to fall by around 35% compared to 2018 for the reference plant.

RESULTS

Figure 7 shows the results of this analysis in terms of levelized cost of electricity (LCOE) for all plants and locations considered in this study assuming a 25 year economic life and 7.5% real weighted average cost of capital (WACC), with countries sorted according to the price index used from lowest to highest. From this figure it can be seen that countries with low DNI resource like Germany are not suitable for CSP applications, since the LCOE values for such countries are very high compared to those with annual DNI resource above 1800 kWh/m². On the other hand, countries like Morocco and Saudi Arabia with much better solar resources (high DNI) and low local costs are already highlighting how attractive CSP can be from a cost perspective alone. With cost reductions and performance improvements by 2030, the economic attractiveness of CSP will only improve as long as the market expands.

The overall picture for solar tower plants is similar than for parabolic trough plants, as already mentioned in part, because of the convergence in installed costs and performance of the two technologies by 2030. If one compares India and Canada with almost the same annual DNI resource (India: 1906 kWh/m² versus Canada: 1856 kWh/m²), the strong impact of the relative local content costs becomes evident (a price index of 31 vs. 111) and also the latitude (26° vs. 50°) CSP plants installed at higher latitudes suffer from lower sun angles reducing the optical efficiency of the solar fields.

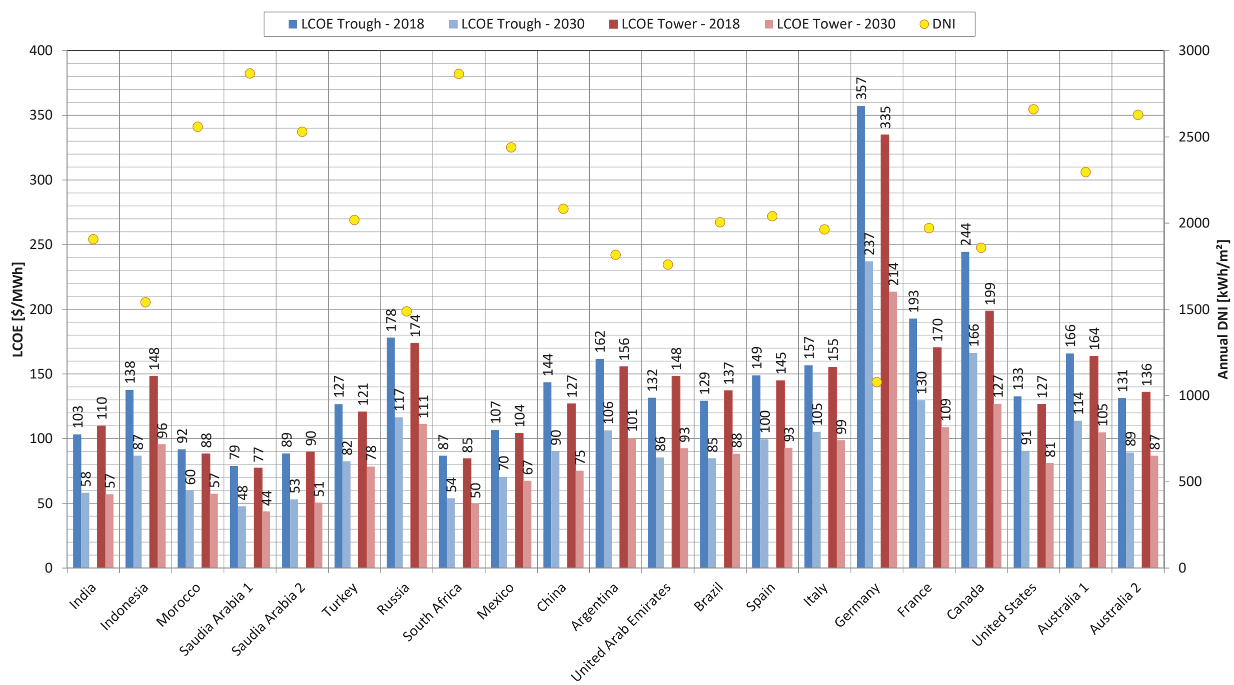

FIGURE 7. DNI resource and calculated LCOE for all CSP plants in 17 G20 states as well Morocco and UAE sorted by price index

LCOE values for troughs and towers are close to each other for sites with low latitudes like Saudi Arabia, South Africa, and Morocco but differ more for high latitude sites like Germany and Canada. There is no clear cost advantage of one technology neither for 2018 nor for 2030 but it varies from country to country. It should be mentioned that the meteorological datasets for all sites used in this study are mainly based on satellite data and therefore uncertainties of up to 15% or more for DNI have to be considered if these are to be translated into specific site costs. More importantly, local air quality is not considered, with clear sky conditions assumed for all sites. This may have a crucial impact on the choice between solar towers or parabolic trough, as performance is proportionately degraded more by air quality issues in solar tower plants. This parameter may also have an impact on the size of large solar tower plants as it may economically limit heliostat field size. Lower visibility caused by high dust and humidity loads in the first 10 to 50 m above ground level would reduce the optical efficiency of solar tower fields considerably and thus increase the LCOE.

Sensitivity Analysis: DNI and the Impact of Local Costs

This section shows the sensitivity of results to the relative price index assumptions, as well as highlighting the sensitivity to resource quality.

It is well known that DNI resource has a very strong impact on LCOE and this is demonstrated in Figure 8 which has been generated by setting the price index for all sites to 100, thus eliminating local cost effects in order to show the impact of DNI. A power law gives a reasonable approximation of the LCOE dependency on annual DNI sum. There is of course some scattering, more pronounced for parabolic trough plants, which is mainly caused by the site latitude. E.g.: The blue square at 1856 kWh/m² and 233 $/MWh represents the parabolic trough plant in Canada at 50.2°N, while the blue square at 1759 kWh/m² and 158 $/MWh represents the trough plant in UAE at 24.75°N. The impact of latitude is lower for solar tower technology (they show less vertical separation in Figure 8). The reason for this different dependency is that solar towers suffer less from low sun angles at high latitudes than parabolic trough collectors.

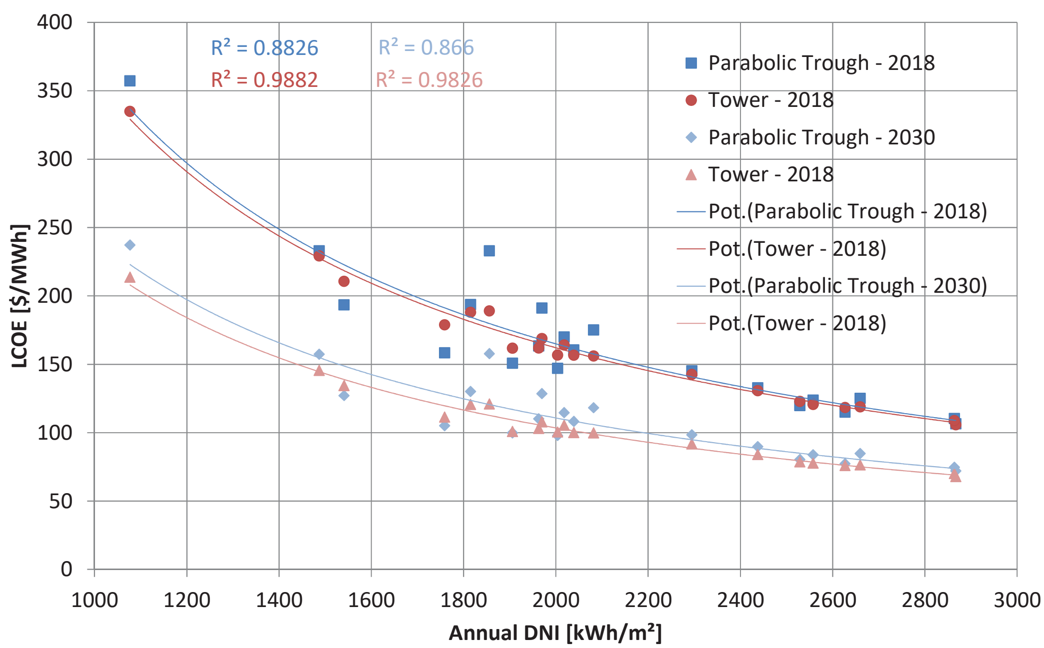

FIGURE 8. LCOE for all sites and plant types with price index set to 100 to show the impact of the DNI resource. Lines represent potential law fit curves with their respective R^2 mentioned in the graph.

In Fig. 9 the impact of price index for parabolic trough systems in 2018 is shown. The red columns are representing the results using a price index according to Fig. 4 while the blue columns show the LCOE using a price index of 100 for all countries. The variation in LCOE is therefore primarily due to the impact of DNI on the solar field optimization. As one would expect, the largest impact occurs for those countries with the highest and lowest price index while the LCOE for Germany is not affected since its individual index is 100. The graph is shown only for troughs in 2018 since the other systems and years show a very similar relationship.

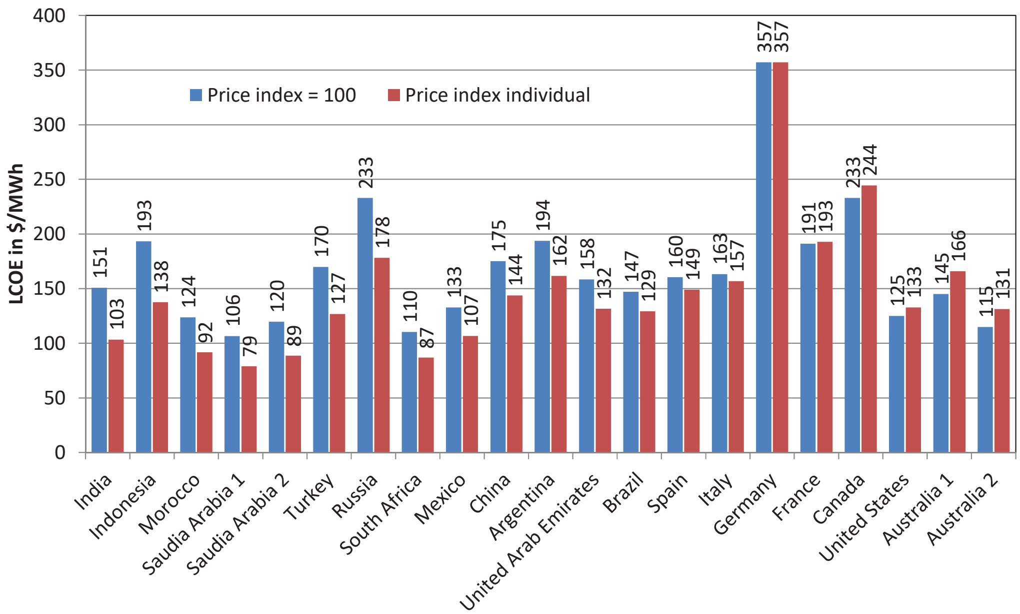

FIGURE 9. Impact of price index on LCOE for parabolic trough plants in 2018.

CONCLUSIONS

Solar resource (DNI) is the most important parameter for LCOE but also local costs and latitude may have a considerable impact. The price index for the G20 countries varies from 31 (India) to 132 (Australia) in 2017. Together with local content of about 40 to 50% the impact of this parameter is also noticeable and would lead to a factor of 2.2 to 2.5 in LCOE with all other parameters being identical. Furthermore the site latitude is important which is particularly valid for parabolic trough plants suffering from high latitudes.

LCOE for parabolic trough and solar tower plants are expected to decrease considerably (31-44% for parabolic trough plants and 35-48% for solar tower plants) between 2018 and 2030 but without a clear advantage for one of these technologies. By 2030, assuming a 7.5% WACC, the LCOE of dispatchable CSP electricity could fall to between USD 44 and USD 100/MWh in the G20 where DNI is sufficiently high to economically support a CSP plant. If the current low interest rate regime continues out to 2030 and a lower WACC can be achieved (as has been case, for instance in UAE), then costs could be even lower. This could provide an attractive solution to balancing low-cost variable renewables as their share increases.

The cost decrease for the 2 CSP technologies investigated here is caused by different mechanisms. For solar tower plants it is expected that there will be a kind of evolutionary development without major modifications of the general design but for parabolic trough plants a switch over to molten salt as heat transfer fluid is expected. This results in a simplified plant layout, higher power block efficiency and lower storage costs.

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