Libya - Supporting Electricity Sector Reform (P154606)

Contract No. 7181909 - Task D: Strategic Plan for Renewable Energy Development

Least Cost Expansion Plan Report Technology Review
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<th>Description</th>
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<td>Capital Expenditures</td>
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<tr>
<td>CCGT</td>
<td>Combined Cycle Gas Turbine</td>
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<td>CRS/CR</td>
<td>Central Receiver System</td>
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<td>CSP</td>
<td>Concentrating Solar Power</td>
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<td>DNI</td>
<td>Direct Normal Irradiation</td>
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<td>DSG</td>
<td>Direct Steam Generation</td>
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<td>ENTSO</td>
<td>European Network of Transmission System Operators</td>
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<td>ESS</td>
<td>Energy Storage System</td>
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<td>FLH</td>
<td>Full Load Hours</td>
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<td>GECOL</td>
<td>General Electric Company of Libya</td>
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<td>GHI</td>
<td>Global Horizontal Irradiation</td>
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<td>GI</td>
<td>Global Irradiation</td>
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<td>GT</td>
<td>Gas Turbine</td>
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<td>HFO</td>
<td>Heavy Fuel Oil</td>
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<td>HRSG</td>
<td>Heat Recovery Steam Generator</td>
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<td>HTF</td>
<td>Heat Transfer Fluid</td>
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<td>IDC</td>
<td>Interest During Construction</td>
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<td>IEC</td>
<td>International Electro-chemical Commission</td>
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<td>IGBT</td>
<td>Insulated Gate Bipolar Transistor</td>
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<tr>
<td>IPP</td>
<td>Independent Power Producer</td>
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<tr>
<td>IRR</td>
<td>Internal Rate of Return</td>
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<td>ISCC</td>
<td>Integrated Solar Combined Cycle</td>
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<td>ITRPV</td>
<td>International Technology Roadmap for Photovoltaic</td>
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<td>LCEP</td>
<td>Least Cost Expansion Plan</td>
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<tr>
<td>LCoE</td>
<td>Levelized Cost of Electricity</td>
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<td>LLJ</td>
<td>Low Level Jet</td>
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<td>LVRT</td>
<td>Low Voltage Ride Through</td>
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<td>OPEX</td>
<td>Operational Expenditures</td>
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<tr>
<td>PID</td>
<td>Potential Induced Degradation</td>
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<td>PPA</td>
<td>Power Purchase Agreement</td>
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<td>PSP</td>
<td>Private Sector Participation</td>
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<td>PT</td>
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<td>PV</td>
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<td>RE</td>
<td>Renewable Energies</td>
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<td>REAOL</td>
<td>Renewable Energy Authority of Libya</td>
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<tr>
<td>SCA</td>
<td>Solar Collector Arrangement</td>
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<td>SCGT</td>
<td>Simple Cycle Gas Turbine</td>
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<tr>
<td>SM</td>
<td>Solar Multiple</td>
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<tr>
<td>STATCOM</td>
<td>Static Compensators</td>
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<td>SPREL</td>
<td>Strategic Plan for Renewable Energies in Libya</td>
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<tr>
<td>TES</td>
<td>Thermal Energy Storage</td>
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<tr>
<td>TMY</td>
<td>Typical Meteorological Year</td>
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<tr>
<td>TSC</td>
<td>Thyristor Switched Capacitors</td>
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<tr>
<td>WACC</td>
<td>Weighted Average Capital Cost</td>
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<tr>
<td>WB</td>
<td>World Bank</td>
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<tr>
<td>WTG</td>
<td>Wind Turbine Generator</td>
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1. High Level Review of Technologies

The goal of this review is to narrow down the many solar and wind technologies available to most suitable for the LCEP. Finding most suitable options does not mean excluding RE options or favouring one technology alternative over another, but configuring the set of wind and solar technologies most competitive in the LCEP optimization both in terms of technical performance and commercial performance within a future PSP procurement process.

It is important to keep in mind that the main objective of the LCEP is to establish an optimized RE mix and not to perform extensive quantitative or scientific analyses of the existing technologies and their market. Such analyses shall be part of a different study and they will not add value to the LCEP objective, i.e. determining a least cost mix of PV, CSP and wind technologies. Thus, this section deals with a qualitative high-level analysis focused on:

- Maturity of technology;
- Market outlook of the technology;
- Technology risks;
- Track record;
- Scalability;
- Costs and potential of cost reduction;
- O&M costs;
- Consumption of utilities with focus on water and its reduction by implementation of dry-cooling systems for CSP;
- Efficiency;
- Applicability under prevailing climate conditions;
- Standalone capabilities (e.g. distributed generation, island generation, rooftop applications); and
- Load-follow capability in conjunction with energy storage.

Concessional financing options for demonstration projects in Libya

This review will start considering the technologies described below:

- Concentrating Solar Power:
  - Parabolic trough with oil as Heat Transfer Fluid (HTF);
  - Central Receiver Systems (CRS) with molten salt or water/steam as HTF;
  - Fresnel technology generating saturated steam;
  - (Parabolic dish); and
  - Thermal energy storage options with focus on molten salt two tanks storage.

- Photovoltaics:
  - Different module types:
    ♦ Monocrystalline Si (Mono-Si);
    ♦ Multicrystalline Si (Multi-Si);
    ♦ Thin-film silicon/amorphous silicon cells (a-Si);
    ♦ Copper-indium/gallium-diselenide/disulfide solar cells (CIGS);
    ♦ Cadmium telluride solar cells (CdTe);
    ♦ Gallium arsenide solar cells (GaAs);
  - Different tracking systems; and
  - Different inverter concepts.

- Wind:
  - Onshore and offshore;
  - Different turbine types covering typical commercially available wind turbine types; and
Different hub heights and capacities.

## 1.1 Concentrating Solar Power

This section deals with the qualitative aspects for the Concentrating Solar Power (CSP) technologies within the framework of the current and mid-term evolution of the Libyan conditions.

In general, CSP systems use combinations of mirrors or lenses to concentrate direct beam solar radiation to produce forms of useful energy such as heat and electricity. Unlike flat plate photovoltaics (PV), they are not able to use radiation that has been diffused by clouds, dust or other factors. This makes them best suited to areas with a high percentage of clear sky days, in locations that do not have smog or dust. The configurations that are currently used commercially in order of deployment level are:

- Parabolic Trough (PT);
- Central Receiver tower (CR);
- Linear Fresnel (LF); and
- Solar dishes (e.g. Stirling dish).

Each technology boasts particular advantages and in some cases particular market segments. Project and technology developers are actively pursuing all types of CSP technologies, however PT and CR are by far the dominant technologies in the sector.¹

Solar irradiance at the earth surface is relatively low, reaching around 1,000 W/m² at solar noon in most places at sea level. This is sufficient for low to mid temperature thermal conversion systems and direct semiconductor electricity conversion systems. For higher temperature conversions and thermo-chemical processes, this irradiance needs to be concentrated from 50 to over 1,000 times, reaching irradiance levels of 50 suns to over 1,000 suns. Concentrating solar power achieves this through the use of optical elements that collect the irradiance over a large area and focus it onto a smaller image area. This concentrated power can then be used by various systems to produce electricity via Concentrated Photovoltaics (CPV) or via solar thermal systems. The latter are referred to generically as CSP.

In general, CSP technologies aim to use optical systems to concentrate direct beam solar irradiance (or Direct Normal Irradiance), collect its energy as heat in appropriate fluids and use thermodynamic cycles to produce work and so be able to generate electricity. In this respect, some CSP technologies are eminently compatible with traditional steam turbine based power plants and design. Most of the CSP plants are essentially a conventional thermal power plant with a solar field providing the heat input instead of a fossil fuel heat source. CSP is not a new technology; one of its first manifestations dates from the early 20th century in Egypt, where it was used for water pumping for irrigation.

But with the introduction of the combustion engine, powered from cheap oil, the technology did not spread. Only after the oil crisis of the late 1970’s interest in non-fossil power generation raised again and with public support in the 1980’s nine parabolic trough power plants were constructed in the United States - the Solar Electricity Generating Stations (SEGS). Together, they have a capacity of 354 MW and are still operating today, proving the durability of this technology. After the oil crisis, the interest in this technology dwindled again and it took until 2005 for CSP to resurface, when the Saguaro Solar Facility with 1 MW was built in Red Rock, Arizona, followed by the 64 MW parabolic trough power plant Nevada Solar One in the Mojave Desert in 2007. Europe saw the introduction of commercial

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¹ K Lovegrove, W. Stein (2012), Concentrating solar power technology – Principles, developments and applications (with chapters from Dr. Richard Meyer and Martin Schlecht, Managing Directors Suntrace GmbH), page 7
scale CSP plants in 2008 when the 50 MW parabolic trough plant Andasol 1 was built in the Spanish province of Andalusia. Subsequently and due to different incentive schemes, a number of CSP plants have been built mainly in Spain and the United States. In recent years, several CSP projects have been realised in new markets such as Morocco’s 160 MW NOOR I parabolic trough plant, South Africa’s 100 MW KaXu SolarOne parabolic trough plant or the 100 MW Shams-1 parabolic trough plant in Abu Dhabi which uses a gas booster to improve the plant’s overall efficiency and dispatchability for instance.

Solar thermal power plants can be divided into two groups: point-focusing systems and line-focusing systems. Solar tower systems and Dish-Engine systems are point-focusing systems, whereas parabolic trough and Fresnel systems belong to the line-focusing group. The configurations that are currently used commercially in order of deployment level are:

1.1.1 Parabolic Trough

Parabolic trough-shaped mirrors produce a linear focus on a receiver tube along the parabola's focal line as illustrated in Figure 1-1. The solar field consists of parallel rows of Solar Collector Assemblies (SCA) and each two rows are combined to one so-called "loop". Each loop is connected to a "cold" and a "hot" header pipe, which feeds the loop with cold Heat Transfer Fluid (HTF) and drain off hot HTF respectively. Hot HTF flows to the power block and transfers its containing heat within the steam generator to the water-steam cycle. Cold HTF is led back to the solar field. The generated steam expands in a steam turbine generator unit, which finally generates electricity.²

Figure 1-1: Schematic illustration of a Parabolic Trough Power Plant

The complete assembly of mirrors plus receiver is mounted on a frame that tracks the daily movement of the sun on one axis. Relative seasonal movements of the sun in the other axis result in lateral movements of the line focus, which remains on the receiver but can have some spill at the row ends.

Solar Collector

For Parabolic Trough technology, the heat is generated in the solar field, which is subdivided in loops. One loop consists of four collectors with 10-12 collector modules. A typical 50 MWₑ plant in Spain has approximately 600 collectors; each collector is 5.7 m wide and 150 m long. A typical SCA consist of

² K Lovegrove, W. Stein (2012), Concentrating solar power technology – Principles, developments and applications (with chapters from Dr. Richard Meyer and Martin Schlecht, Managing Directors Suntrace GmbH), page 7
the parabolic reflectors on metal structure, the receiver tubes and heat transfer fluid piping, the pylons (steel structure), and the single axis tracking system.

The parabolic reflectors (typically glass mirrors) have a highly reflective and minimum absorbing surface assembled on a metal structure. The parabolic reflectors are designed to concentrate the DNI up to a 90 times. This irradiance is focused on to receiver tubes, which are installed in the focal line of the parabolic reflectors. The receiver tubes are also known as heat collecting elements. The parabolic trough structure is supported by pylons with a single axis tracking system, which includes the drive, the sensors and the controls. The parabolic trough collectors are typically aligned North-South and are arranged in parallel rows and connected as a loop. Exemplary collectors are shown in Figure 1-2 below.

Figure 1-2: HelloTrough (left) and Ultimate Trough (right) parabolic trough solar collectors (Source Images: Schlaich Bergermann Partner - Sbp)

Heat Transfer Fluid

The HTF is typically synthetic oil, in very limited cases, mineral oil or steam as well. It is pumped through the tubes and heated with a resulting temperature increase from about 290 °C to 390 °C. The heated HTF will serve a steam generator of the steam cycle, which is similar to conventional steam generators. For parabolic trough plants, using synthetic oil as HTF the temperature is limited to below 400°C, as the oil decomposes above this temperature. Using molten salts or direct steam conversion technology, higher temperatures up to 550 - 600°C could be reached and would increase steam cycle efficiencies. However, parabolic trough technology using molten salt as HTF is still under research and has not yet reached commercial scale. Moreover, the dispatchability of a direct steam system is limited due to the available storage technology typically being a steam accumulator.

Thermal Energy Storage

The thermal energy collected by the solar field can either be used directly for steam generation to run a steam turbine, or stored in a thermal energy storage (TES). For parabolic trough systems, an indirect two-tank molten salt TES is most common allowing to dispatch the collection of solar energy from power generation for several hours. Thereby, the collected thermal energy is transferred from the HTF to the molten salt through an additional heat exchanger and stored in a hot tank. During discharge, the hot molten salt is pumped through the heat exchanger to the cold tank transferring thermal energy back to the HTF, which in turn transfers the thermal energy to the water/steam cycle.
The main advantage of a CSP system compared to other solar power technologies, such as PV, is the dispatchability of power generation through the TES. For parabolic trough technologies, a synthetic oil based system with an indirect two-tank molten salt TES is most common.

### 1.1.2 Central Receiver System

A central receiver tower system involves an array of heliostats (large mirrors with two axis tracking) that concentrate the sunlight onto a fixed receiver mounted at the top of a tower, as illustrated in Figure 1-3. This allows sophisticated high efficiency energy conversion at a single large receiver point. Higher concentration ratios are achieved compared to linear focusing systems and this allows thermal receivers to operate at higher temperatures with reduced losses. In general, solar towers form a higher proportion of newer projects, indicating that the technology is becoming more popular.

![Central Receiver Tower Plant](image)

**Figure 1-3: Schematic Illustration of a Central Receiver Tower Plant**

Central receiver plants can be classified in three main groups based on the working fluid that they use, namely: water/steam, molten-salt, and air. A schematic representation of the first two concepts can be found in Figure 1-4. The third technology uses air as HTF. The concentrated solar radiation is used to heat the air before it is fed to the combustion chamber of a gas turbine. However, these systems are still in R&D phase and are therefore excluded form further assessments.

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3 K Lovegrove, W. Stein (2012), Concentrating solar power technology – Principles, developments and applications (with chapters from Dr. Richard Meyer and Martin Schlecht, Managing Directors Suntrace GmbH), page 8
Figure 1-4: Solar Towers with different working fluids, (a) water/steam, (b) molten-salt, typically including molten salt tanks for storage (Source: Giuliano, Buck & Eguiguren, 2011)

**Direct steam tower technology**

In water/steam power towers the HTF is water and steam. The concentrated solar energy receives onto an external tubular receiver. Inside the tubes, the HTF flows in upward direction and is evaporated and superheated. The steam leaves the receiver with around 550°C and a pressure of 160 bar. The superheated steam is transferred to a conventional steam turbine to drive the electrical generator. The main advantage of the direct steam technology is that no heat exchangers and intermediate HTF is needed. The disadvantage is the storage technology. Until now, commercially proven storage can only be realized with a steam accumulator. The adoption of a molten salt based storage system with a direct steam receiver is still under development. The same accounts for a concrete based indirect storage system for direct steam generation plants.

**Molten salt tower technology**

In the molten-salt power towers a mixture of 40% Potassium nitrate and 60% Sodium nitrate is typically used as working fluid. From a cold storage tank, where the salt is stored at 290°C, it is circulated in upward direction through an external receiver, in which it is heated to 565°C and then passed to a hot salt tank. The HTF molten salt is pumped from the hot salt tank to a steam generating system, to the cold storage tank. The steam generator is producing superheated steam to drive the conventional Rankine cycle. The salt has to be kept at a minimum temperature of ca. 250°C to prevent solidification.

An example of an early development of a molten salt tower was the R&D project Solar Two plant in USA. The Solar Two plant was in operation from 1996 to 1999. The working principle has been adopted by existing tower technology suppliers such as SolarReserve and SENER. R&D with molten salt technology is currently aiming to increase the operating temperature from current 565°C to 620°C and more in order to operate the power plant cycle at supercritical steam conditions with higher efficiencies. But R&D is also investigating molten salt compositions to reduce the freeze temperature and consequently reduce the electric consumptions for anti-freeze protection.

Nowadays, the molten salt-based solar tower has become the most attractive tower technology configuration in terms of dispatchability due its efficient direct two-tank molten salt TES.
Solar field

The heliostat field of a solar tower system consists of an array of 2-axis tracking mirrors that reflect incident direct beam sunlight onto an elevated receiver. The heliostats must be accurate enough to not degrade the solar image excessively (beam error less than 2-3 mrad) and rigid enough to sustain gravity and wind loads while maintaining this accuracy. Current commercial heliostats range from 1m² to 150m². A typical heliostat is shown in Figure 1-5 below.

![Typical heliostat](image)

Figure 1-5: Typical heliostat

Receiver

The receiver is designed to absorb the concentrated solar energy and transfer it to a heat transfer fluid. According to their configuration, receivers can be of the external or cavity type. Cavity receivers are located within some sort of protective box, whereas external receivers are directly exposed to the environment. In general, some of the advantages of the cavity receivers are: less radiative and reflective losses, and less degradation of the receiver coatings. However, some of the advantages of external receivers are: smaller absorber area requirement, smaller receiver mass requirement, and lower costs. For utility scale applications, an external receiver concept is typically applied.

1.1.3 Linear Fresnel

Linear Fresnel reflector systems produce a linear focus on a downward facing fixed receiver mounted on a series of small towers as shown in Figure 1-6. Long rows of flat or slightly curved mirrors move independently on one axis to reflect the sun's rays onto the stationary receiver. For thermal systems, the fixed receiver not only avoids the need for rotary joints for the heat transfer fluid, but can also help to reduce convection losses from a thermal receiver because it has a permanently down-facing cavity.\(^4\)

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\(^4\) K Lovegrove, W. Stein (2012), Concentrating solar power technology – Principles, developments and applications (with chapters from Dr. Richard Meyer and Martin Schlecht, Managing Directors Suntrace GmbH), page 8
Figure 1-6: Schematic illustration of a Fresnel Reflector Power Plant

The proponents of the LF approach argue that its simple design with near flat mirrors and less supporting structure, which is closer to the ground, outweighs the lower overall optical and thermal efficiency. To increase optical and ground-use efficiency, compact linear Fresnel reflectors use multiple receivers for each set of mirrors so that adjacent mirrors have different inclinations in order to target different receivers. This allows higher packing density of mirrors, which increases optical efficiency and minimizes land use.  

The LF technology has not been able to establish itself in the CSP market till now. There are only a few suppliers left and large-scale commercial projects have yet to be realized. Therefore, the LF technology will not be assessed further for this assignment.

1.1.4 Parabolic Dishes

Dish systems, like troughs, exploit the geometric properties of a parabola, but as a three-dimensional paraboloidal as shown in Figure 1-7. The reflected direct beam radiation is concentrated to a point focus receiver and can heat this to operating temperatures of over 1,000°C, similar to tower systems. Dish systems offer the highest potential solar conversion efficiencies of all the CSP technologies, because they always present their full aperture directly towards the sun and avoid the ‘cosine loss effect’ that the other approaches experience.  

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5 K Lovegrove, W. Stein (2012), Concentrating solar power technology – Principles, developments and applications (with chapters from Dr. Richard Meyer and Martin Schlecht, Managing Directors Suntrace GmbH), page 10  
6 K Lovegrove, W. Stein (2012), Concentrating solar power technology – Principles, developments and applications, page 33: When a mirror is reflecting off-axis, the apparent area of the mirror, as seen from the sun, is reduced according to the cosine of the incidence angle. Assuming that the aperture area of the concentrator to be equal to the mirror area, this reduction in apparent area then directly reduces the concentration ratio of the concentrator, hence it is referred to as a cosine loss, although strictly speaking the energy was never collected in the first place.
They are, however, the least commercially mature and application of such technology in large-scale parks seems to be very unlikely due to their small-scale character. Having in mind this very limited suitability for large-scale application, this technology is excluded from further investigations.

1.1.5 Maturity of Technology – Track Record

The start of construction of the SEGS ("Solar Electric Generating Systems") plants in 1984 can be considered as the beginning of commercial CSP deployment. Although no large power plants were built in the period from 1990 to 2005, since than installed capacity is steadily rising. With Spain and the United States continue being the global leaders, the CSP market had a total installed capacity of over 4.8 GW in 2015 as shown in Figure 1-8 below. The lion's share of the CSP plants in operation using parabolic trough collectors. Additionally, a number of projects are expected to be realized in the near future, with a notable trend towards developing countries and regions with higher solar radiation. Examples include the recent 2017 Dubai tender, where record-breaking tariffs have resulted from a competitive auction process, or China’s ambitious 5 GW CSP target for 2020 for instance.
Parabolic trough technology is commercially the most advanced CSP technology. Already in the 1980s and early 1990s, nine parabolic trough plants - the Solar Electric Generating System (SEGS) plants, with a total capacity of 354 MWₑ - have been built in the Californian Mojave Desert in the United States. The plants have remained operational for over 30 years now, providing a large experience of operation and maintenance. Since 2007, several trough plants with a combined capacity of over 2GW have been built, mainly in the United States and in Spain. Such as a 64 MWₑ power plant near Boulder City, in the United States, and numerous 50 MWₑ power plants in Spain, of which the first commercial one installed was the 50 MWₑ plant Andasol 1 with a thermal storage with of 7.5 hours of full load operation capacity. Thus parabolic trough is the most adopted and mature CSP technology so far.

The Solar Tower technology can also look back on a long track record. An example of an early development of a molten salt tower was the R&D project Solar Two plant in USA. The Solar Two plant was in operation from 1996 to 1999. Several commercial solar tower projects using direct steam have started operation during the last 10 years, as for example PS10 and PS20 in Spain, or Ivanpah with 377 MWe in USA, and Khi Solar One with 50 MWe in South Africa. Besides the first commercial molten salt solar tower plant Gemasolar with 20 MWe that went operational in 2011, the large-scale projects are mainly still under construction, such as Atacama-1 with 110 MWe and NOOR III with 150 MWe. The 110 MWe molten salt-based solar tower Cresent Dunes has reached commercial operation in 2015.

The operational experience and installed capacity varies between the technologies with about 86% of the installed CSP capacity being parabolic trough technology, about 10% being central receiver tech-

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nology and about 4% being Linear Fresnel from a total of 4.8 GW installed. It should be noted that there is a tendency towards central receiver technology in the market.

1.1.6 Market Outlook of the Technology

Nowadays the industry has shown a clear tendency towards either parabolic trough collector systems with thermal oil as HTF or solar tower systems with molten salt, both equipped with medium to large TES also based on molten salt. Although the industry still features innovative and very promising technologies such as Fresnel or parabolic trough with molten salt as HTF, these technologies have neither undergone the operational track record nor the cost reduction experienced by the two technologies mentioned in the beginning.

![CSP projects around the world](http://www.integroprj.com/solarpanel)

**Figure 1-9: CSP projects around the world**

There are currently 1,260 MWe of CSP capacity under construction and 2,709 MWe under development as shown in Figure 1-9. Besides the traditional markets in the US and Spain, several developing markets for CSP technologies have emerged during the last years such as the United Arab Emirates, Chile, South Africa, Israel, India, Saudi Arabia, and in particular Morocco. The CSP technology continues to push into emerging markets offering sufficient solar irradiation, the political will, and the regulatory framework for the technology deployment.

1.1.7 Technology Risks

The PT technology is commercially the most advanced CSP technology offering experienced market players and implementation standards during construction and operation. With respect to the solar tower technology, there are a limited number of technology providers with hands on experience from utility scale solar tower projects being under operation, such as for example SENER, Abengoa, Brightsource, and SolarReserve. Moreover, and compared to parabolic trough, there is still a lack of standards for tower technologies, in particular regarding the solar field components which increases costs for risk-reduction. The power block of a CSP system does not differ significantly from conventional fossil fuelled power plants and experienced industry players active in conventional power plants are also offering the water-steam cycle for CSP plants.

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In general, the risks for CSP projects are classified into project-endogenous and project-exogenous risks. Project-endogenous risk can be controlled by the project company or one of the project participants, whereas, project-exogenous risk affects the project beyond the orbit of the project parties. This differentiation is vital because through contracting and risk allocation exogenous risks, such as market risk, can be allocated to a project party. Hence, the exogenous risk can be transferred into an endogenous risk. This is crucial because endogenous project risks are obviously more controllable. An overview of essential risks associated with a CSP project is given in Table 1-1 below.

Table 1-1: Overview of essential endogenous and exogenous risks in CSP projects

<table>
<thead>
<tr>
<th>Endogenous Risks</th>
<th>Exogenous Risks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction risk</td>
<td>Delivery risk</td>
</tr>
<tr>
<td>Technology risk</td>
<td>Market risk</td>
</tr>
<tr>
<td>Operational risk</td>
<td>Resource risk</td>
</tr>
<tr>
<td>Management risk</td>
<td>Financial risks</td>
</tr>
<tr>
<td></td>
<td>Political and sovereign risk</td>
</tr>
<tr>
<td></td>
<td>Force Majeure</td>
</tr>
</tbody>
</table>

One of the most important objectives is the managing and mitigating of these risks efficiently. Hence, the process of risk management in project financing is vital.

1.1.8 Scalability

The scalability of a CSP system varies with the applied technology and the respective solar field of the system. A solar tower plant for instance is restricted in the solar field size due to the decreasing optical efficiency of the outer heliostats with increasing distance to the central receiver. Increasing cosine losses mainly causes this. Thus, the average efficiency of the solar field decreases. The optimal size of the solar field needs to be determined during a techno-economic optimisation. Typically, solar tower plants are designed for turbine capacities of 100 MW or more depending on the project specific boundary conditions with a trend towards larger plant capacities.

The line focusing systems, such as parabolic trough, are also restricted in the solar field size. The HTF needs to be pumped through the cold header section to the absorber tubes of each loop and back to the power block facilities through the hot header section. The acceptable pressure and heat loss of the pipes is a factor to be considered for sizing the solar field. Nowadays, PT power plants are designed for capacities of 150 MWe and more, while the typical size of PT projects in operation is 50 MWe, also due to the former regulatory framework, e.g. in the Spanish market.

1.1.9 Costs and Potential of Cost Reduction

The up-front investment for a CSP power plant, though continuously falling, is high compared to other renewable technologies such as PV, which is also one of the main challenges of this technology. The CAPEX for a CSP power plant can be divided in two main expenses, i.e. EPC cost and developer cost. The developer costs are highly project specific and difficult to generalize from project to project. The EPC cost during the construction period of the plant includes a turnkey service where the EPC contractor is responsible for the engineering, procurement and construction of the CSP plant, guaranteeing a minimum energy yield of the plant under certain specific solar radiation conditions.
Since the operation of a CSP plant relies on free solar irradiance as the energy source, the running costs are notably reduced when compared to conventional fossil fuel power generation. As a result, the OPEX of a CSP plant is very small compared to the initial investment, although it still remains significant. OPEX includes insurance, maintenance, labour cost, utilities (water, backup fuel, electricity), and fixed service contracts.

The learning rate and cost reduction potential for the CSP technology has not been used up till now. The cumulative installed CSP capacity of 4.8 GW (2015) is rather low compared to other renewable energy technologies such as PV. The historical cost variation for CSP projects is relatively high due to individual boundary conditions to be considered for each project including solar irradiation potential at the project site, development cost, technology type and TES capacity, and regulatory framework. Putting these aspects into perspective, a price reduction and learning rate between 5% and 12% with an average of 8.5% can be observed as shown in Figure 1-10.

![Figure 1-10: Experience curve of CSP projects, by developer, amount of storage, and location (NREL, 2016)](image)

In 2015, the levelized cost of electricity (LCoE) for a CSP PT and CR plant with TES were in the range of 0.15 to 0.19 USD/kWh as shown in Figure 1-11. By 2025, the LCoE for PT and CR technology could decrease by 37% and 43% respectively, reaching 0.09 to 0.11 USD/kWh for PT and 0.08 to 0.11 USD/kWh for CR technology (IRENA, 2016). Current developments in 2017 have seen a further substantial decrease in particular the latest 2017 tender for Dubai, which led to a price of 0.073 USD/kWh for a combination of parabolic trough and solar tower technology and a total of 700 MW capacity. The prices decrease is generally related to changing policy incentives moving from FIT schemes to competitive auction schemes.
1.1.10 Consumptions

Due to its inherent nature of thermal power plants CSP plants usually require other media to work such as water and fossil fuels (for back-up power).

Water consumption

CSP technologies generate electricity under the same thermodynamic principles used in coal or nuclear power plants; being the main difference the fuel/source used to turn water into steam. There are two major water processes in a steam turbine system - the steam cycle and the cooling process. Most of the water is consumed during the cooling of the process. Fossil and nuclear power plants use the same wet-cooling technologies as those for CSP.

Water is used to produce steam to turn the steam turbines; this water is recycled for the generation of steam in the “closed-loop” steam cycle. Theoretically, water is not lost in the steam production cycle (though real-world imperfections necessitate some “make-up” water to compensate for leaks in the system). Steam is cooled in a condenser and condensed back to a liquid water state to be reused.

The condenser itself is then cooled. For wet cooling of the condenser, the most common technology is to use a separate circuit of water to remove the heat from the condenser; this water then flows to an evaporative cooling tower that dissipates the collected thermal energy to the environment. Most of this cooling water is lost as clouds of water vapour to the atmosphere as the condenser water contacts the air and the cooling tower. Alternatively, wet cooling can also occur by sending the condensed steam directly to the cooling tower. The large-scale CSP facilities operating in the United States all use wet cooling.

In areas where water supply is limited, such as in desert areas or far away from water resources, the dry cooling concept may be applied. This technology uses air, which is blown over an extensive network of steam pipes designed with convective cooling fins to dissipate the heat energy over their surface area. Minimal water is used or consumed in dry cooling. However, air has a much lower capacity.
to transport heat than water; therefore, dry cooling generally is less efficient than wet cooling in removing heat.

Dry cooling substantially reduces water consumption with a limited impact on plant efficiency and generating costs. For a 100 MW trough plant, adoption of dry cooling instead of wet cooling reduces water consumption by about 93%. The generating efficiency penalty is 1–3% (with respect to nominal power) but this efficiency is ultimately related to the ambient temperatures of the place. Annual production of electricity is reduced by 2–4% because of a 9–25% increase in the parasitic power requirements associated with the additional equipment for dry cooling (the ranges are due to differences in site characteristics). As a result, generating costs increase by 3–7.5% compared with water-cooling.

Table 1-2: Water consumption of CSP PT and CR technology (adapted from IEA, 2010b)

<table>
<thead>
<tr>
<th>CSP Technology</th>
<th>Water Consumption for Wet/Dry Cooling (m³/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parabolic Trough</td>
<td>3 – 4 / 0.3 - 0.6</td>
</tr>
<tr>
<td>Central Receiver</td>
<td>3 – 4 / 0.3 - 0.6</td>
</tr>
</tbody>
</table>

Auxiliary electricity consumption

The CSP system requires auxiliary electricity consumption to run, among others, the feed water and HTF pumps, the electrical motors for the solar field tracking system, the freeze protection system for molten salts, and several other control systems. The annual auxiliary consumption of CSP plants is typically about 10% of the annual gross electricity produced. Depending on the operating strategy, the auxiliary consumption during the day is typically larger as during the night. Such auxiliary consumption can be covered by lower cost electricity from PV to reduce overall cost of electricity.

1.1.11 Efficiency

The efficiency of a CSP system slightly varies for the different technologies. The molten salt-based CR technology reaches higher HTF temperatures compared to a PT power plant using oil as HTF, and has therefore a higher power block efficiency. The power block efficiency of a CR power plant is about 41-42%, whereas the PT system power block efficiency is typically in range of 38-39%. The typical peak solar to electricity conversion and annual average conversion efficiency for CR and PT systems are shown in Table 1-3 below.

Table 1-3: Solar to electricity efficiency of CSP PT and CR technologies (adapted from IEA, 2010b)

<table>
<thead>
<tr>
<th>CSP Technology</th>
<th>Peak Solar to Electricity Conversion Efficiency</th>
<th>Annual Solar to Electricity Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parabolic Trough</td>
<td>23 – 27 %</td>
<td>15 – 16 %</td>
</tr>
<tr>
<td>Central Receiver</td>
<td>20 - 27 %</td>
<td>15 – 17 %</td>
</tr>
</tbody>
</table>
1.1.12 Applicability Under Prevailing Climate Conditions

The direct normal irradiation (DNI) available at a project site is one of the key criteria for the implementation of a CSP plant. It is generally recognized that an average DNI value of at least 1,800 kWh/m²/year is needed for developing a successful CSP project. Depending on the specific situation this might be even somewhat low. Other factors that affect the suitability of a site are the prevailing climate conditions such as:

- The ambient temperature affects the efficiency of the cooling system and thus the power block efficiency. The higher the ambient temperature, the lower is the efficiency of the cooling system, which in turn leads to a higher exhaust steam pressure of the steam turbine and thus to a lower efficiency of the power block.
- The prevailing wind speed at the project site is crucial for the accuracy of the solar field tracking system, in particular for heliostats. Windbreakers along the project boundary and/or within the solar field can mitigate the impact on the reduced solar field performance due to high wind speed.
- Sand storms might carry sands from the surrounding onto the site possibly affecting the performance of equipment due to soiling or causing damage of equipment. Sand storms threaten the internal set-up can be mitigated by erecting walls and fences at the edges / boundaries of the site.
- Aerosols and/or humidity can affect the production by diffusing parts of the direct solar irradiation before reaching the mirrors and absorber components.

In general, CSP technology is also suitable for harsh environments such as deserts facing high ambient temperatures.

1.1.13 Standalone Capabilities and Load Follow Capabilities

The main advantage of a CSP system compared to other solar power technologies, such as PV, is the dispatchability of power generation through the TES. The solar field, and thus the fluctuating solar resource, can completely be decoupled from electricity generation, if required. Moreover, a CSP system in combination with a long-term TES can supply base load to the grid assuming sufficient thermal energy has been collected during the day to charge the TES. A hybridization with a fossil back up firing system can also be applied if the plant needs to provide base load during the whole year as indicated in Figure 1-12. Through decoupling of the solar resource and the electricity production, the CSP plant is also able to follow a respective load within the limits of the power block.
Figure 1-12: Annual capacity factors for CSP system with and w/o TES and fossil back-up firing

With respect to the auxiliary electricity consumption of a CSP plant during hours without electricity production (e.g. the anti-freeze protection system for molten salt applications or auxiliary consumption during the start-up process), an off-grid CSP system is not recommended, however black start capabilities are generally possible, if required.

1.2 PV

The application of PV power plants has changed distinctly in recent years. Starting with mainly small rooftop installations in rich countries the market has now reached maturity also within the market of big utility scale power plants, which arise almost all over the world.

This section describes the major technology trends focussing on the main components (modules, inverters and mounting systems) and deals with the qualitative aspects of photovoltaic technologies.

Solar photovoltaic plants use the global irradiation (GI), which is converted into electric energy in the solar generator. The solar generator consists of PV modules connected in series to form strings, which are connected in parallel and deliver DC power to the inverters. The inverter converts the DC power to AC power before transforming to the required voltage level allowing evacuation of power to the grid as shown in Figure 1-13 below.
1.2.1 PV Module Technologies

The photovoltaic module technologies differ primarily by the type of technology, which leads to different manufacturing processes, price ranges, manufacturing cost and performance. Photovoltaic module technology is based on the photoelectric effect, in which the photons emitted by the sun impact a semiconductor surface and are absorbed to produce electricity. Different module technologies are described hereafter. With respect to the Libyan energy market situation, major technologies should be favoured providing a long track record with best practice industrial standards and sufficient suppliers for competitive bidding.

Silicon wafer based PV technology accounted for about 93% of the total production in 2015. The share of multi-crystalline technology is now about 68% of total production. In 2015, the market share of all thin film technologies amounted to about 7% of the total annual production.
**Multi-crystalline technology**

This technology has existed since 1981. The manufacturing process is simpler than the one of monocrystalline technology.

**Advantages:**

- Mature and commercially proven technology;
- Long lifetime of panels;
- Low degradation of about 0.5% per year;
- Low installation costs;
- Low production costs;
- Friendlier to the environment, as for example, thin film technology that is using cadmium; crystalline cells are not harmful to the environment; and
- Established global competitions and high number of tier 1 companies.

**Disadvantages:**

- Lower module efficiency in comparison to monocrystalline technology, due to less homogeneous crystal structure: 14-18%;
- Because of the lower efficiency, a larger area is required to reach the same capacity as applicable for mono-crystalline technology; and
- Higher risk of cracks during transport or mounting in comparison to thin film technology.

**Mono-crystalline technology**

The manufacturing process of mono-crystalline modules requires more effort in comparison to other technologies; however, these modules offer higher efficiency – typically within 15-20%.

**The advantages are:**

- Mature and commercially proven technology;
- Long lifetime of panels;
- Low degradation of about 0.5% per year; and
- Lower specific installation costs because of high efficiency compared to the multi-crystalline module technology
- Friendlier to the environment, as for example, thin film technology that is using cadmium; crystalline cells are not harmful to the environment;

**The disadvantages are:**

- The initial investment costs are higher compared to multi-crystalline modules; and
- Higher risk of cracks during transport or mounting in comparison to thin film technology.

**Thin Film technology**

This technology is called Thin Film as in this case the semiconductor material is placed on a substrate material, with only nanometre of thickness. Hence, very low amounts of material are needed. The main semiconductor materials in use are:

- Amorphous Silicon (a-Si);
- Cadmium Telluride (CdTe);
- Copper Iridium Gallium Selenide (CIS / CIGS); and
- Gallium arsenide (GaAs).

Depending on the technology, thin film module efficiencies have reached 11-17%.

Advantages compared to crystalline modules:

- Easier to manufacture, thus lower production costs;
- Homogenous appearance;
- Flexible, hence for use at different applications and surfaces; and
- Less affected by high temperatures and shading.

Disadvantages compared to crystalline modules:

- Faster degradation;
- Lower efficiency leads to greater surfaces for the same capacity;
- Higher costs for mounting, installation, cabling
- CdTe: need of disposal of hazardous waste after end of life, not yet experience in this.
- Thin Film technologies have faced technical problems with degradation in the last decade. A special accuracy is needed in the selection of the product; and
- Very few market players; only First Solar with a significant market share of CdTe based thin film technology.

1.2.2 Inverter Technology

Inverters convert the direct current (DC) produced by the solar modules into alternating current (AC) that can be fed into the grid. In general, there are two different types of inverters, the string inverter and central inverter.

String inverter concept

The individual PV modules are connected in series to form strings. When using string inverters, the DC power from a few strings runs directly into a string inverter where it is converted to AC power. The string inverter is a small unit and can eventually be mounted underneath the PV mounting system. This concept offers higher modularity and flexibility of the system configuration compared to the central inverter concept and is typically applied for PV plants < 1 MW and systems with different array angles and/or orientations. The nominal DC capacity of string inverters is typically below 100kW.

Central inverter concept

When using central inverters, the strings are connected in parallel through combiner boxes and are then connected to the central inverter, which summarize typically between 500 kW to 2.5 MW of DC PV power. In utility scale PV plants, the PV field is generally divided into more parts (subfields), each of them served by an inverter of its own. This configuration is optimal for large systems where production is consistent across arrays. Moreover, the central inverter concept offers lower capacity specific costs and fewer component connections compared to the string inverter concept.

State of the art inverter technology offers a broad range of operational stages, being able to fulfil international grid codes in terms of fault-ride-through and reactive power provision. Moreover, a SCADA
system (Supervisory Control and Data Acquisition) is typically incorporated allowing fully remote operation.

The inverter concept selection needs to be made for each project taken into account the market situation, system cost and expected energy production. Certain central and string inverters can be used as statcoms and provide reactive power. Requirements for reactive power supply are typically arranged in either the grid code, grid connection agreement or potentially the PPA.

1.2.3 Fixed Mounting Structures and Tracking Systems

The photovoltaic panels may be installed on fixed structures or on structures that are tracking the sun’s course during the day, the latter may be of one axis or two axes.

Fixed structures in the northern hemisphere are generally tilted towards the south with an inclination between 10° and 40°. The fixed position of the modules leads to a generation curve with a strong peak at midday on cloudless days. Under certain conditions (e.g. high lease costs, proximity to the equator) east-west facing solar modules can also be an option. The specific yield is lower compared to south-facing power plants, but efficient surface use and a more balanced energy yield in the course of the day are two interesting advantages of this variant. In addition, the specific cost for the mounting structure is lower compared to the south or north orientated fixed-tilt system.

For tracker solutions, the aim is to follow the sun and maintain the panels perpendicular to the axis of incidence of the sun. Thus, a greater efficiency in converting solar energy into electricity can be achieved. The Two-Axis-Tracking can follow the sun both in azimuth and angle - both to the east and west, and depending on the season, follow the inclination during the day and the time of the year.

Advantages of tracking systems:

Tracking systems can harness up to 40% more energy, making them a very attractive alternative in areas of high solar irradiation. Tracking systems are able to keep shading to a minimum but typically require more space for the same power output as compared to a fixed-tilt system. One of the most important aspects of tracking systems is the increased energy yield during the morning and evening hours, which helps to deliver a more constant electricity supply. The constant electricity supply can help for example to reduce the required storage capacity for systems with energy storage facilities.

Single axis tracking systems with horizontal axis facing North to South are best installed in regions close to the equator. This is where they show their true advantage, reaching a yield increase of up to 25 % compared with a fixed installation. However, the single axis tracked system has become advantages against fixed-tilt system in terms of LCOEs also in latitudes far beyond the equatorial region such as Spain or the Middle East due to further price reductions. Especially systems with horizontal axis show a high wind resistance while keeping maintenance efforts relatively low and offering increased electricity production.

Disadvantages of tracking systems:

2-axis tracking systems are 20 to 40 % more expensive than fixed installed systems. Furthermore, tracking systems are more susceptible to failure, due to the number of moving parts and therefore also require more maintenance and have up to 20% higher maintenance costs. Trackers are more susceptible to high wind loads and in areas of high wind speeds the limited warranty for tracker systems may be reduced.
The decision to choose any of the three types of mounting structure is based on a technical and economic evaluation. Extra energy generation must be assessed in comparison to the energy price and to the investment required.

1.2.4 Maturity of Technology – Track Record

Though since the 1950s in the focus of research and development, PV technology did not achieve market maturity until the 1990s supported by renewable energy policies in Germany and USA. As of today, the PV industry can look back on a long track-record and more than a decade of experience in utility-scale power utilisation in international markets. Until recently, the demand for PV installations was concentrated in the OECD countries but the technology has managed to enter several emerging markets in recent years and also for Libya PV technology stands out as a promising option for renewable energy.


Market expansion in most of the world, including the Gulf region, Jordan and Morocco for instance, is due largely to the increasing competitiveness of solar PV, as well as to new government programmes, the relatively simple nature of PV technology compared to others, rising demand for electricity and improving awareness of solar PV’s potential as countries seek to alleviate pollution and CO2 emissions. The technology is bankable i.e. favourable interest rates due to reduced risks.

1.2.5 Market Outlook of PV Technology

Though photovoltaic is mature from a technological and commercial point of view, the potential for further cost reduction is still considered to be high.
The experience curve shows that in the last 36 years the module price decreased by 24% with each doubling of the cumulated module production (see Figure 1-16; source: Fraunhofer ISE). Cost reductions result from economies of scale and technological improvements.
Massive market growth is expected in the next years. The IEA developed three different scenarios for the energy consumption and generation until 2050, based on assumptions about population growth and energy consumption behaviour. Based on these assumptions the authors of the International Technology Roadmap for Photovoltaic (ITRPV) calculated three scenarios. The following cumulative installed PV power in 2050 have been determined:

- low scenario: 4.5 TWp;
- medium scenario: 6.85 TWp; and
- high scenario: 9.17 TWp

The medium scenario is shown in Figure 1-17 below. In the figure, cumulative installed PV module power and annual market calculated with a logistic growth approximation and assuming 6.8 TWp installed PV module power in 2050.
Major market drivers in the next years will be:

- cost reduction and resulting electricity price
- technological improvements
- environmental concerns (e.g.: air pollution, health impacts, global climate change)
- social benefits (e.g.: improved energy access, security and reliability of supply)
- growing interest in citizen control over energy production
- Scalability and simplicity of the technology

### 1.2.6 Technology Risks

Compared to other energy production technologies photovoltaic with its relatively simple and repetitive technology faces comparatively low risks. In the following the focus will be on the main risks regarding completion, operation, function and resource.

#### Completion risk

The most common constructional problems are:

- Complex ground conditions;
- Delayed or wrong delivery of components;
- Bad weather conditions; and
- Incorrect design.

These risks may lead to a cost and/or time overrun in construction or to a completed plant that may not meet the pre-defined performance levels.
Operational and Management risks

All threats during the operating phase that disrupt the production or lead to higher operational costs can be pooled as operational and management risks. Causes for an operational and management risk include poor planning, organization or execution of operational procedures. Hence, the experience of the management personnel is crucial. Possible limitations of production have a negative impact on the output quantity and consequently on generated income. The key consequence in the model is a lower cash flow, i.e. revenues.

Functional risk – PV plant

The functional risk includes the risks that the output is less in quantity or quality. This risk is significant as it can lead to lower revenue and hence, to lower cash flow.

Main risks are:

- Module/Cell quality (e.g. Potential Induced Degradation (PID), Light Induced Degradation (LID), cell or module array mismatch);
- Inverter quality (e.g. insufficient meteorological design (dust, salty air), low efficiency, high malfunctioning rate);
- Design errors (e.g. Inverter design, DC/AC ratio, cable dimension); and
- Grid connection adjustments (e.g. provision of reactive power).

Resource risk – PV plant

The resource risk can be described as the risk that the solar irradiation (the resource) does not meet with respective assumptions/projections. Solar irradiation is (almost) linearly related to projected income and return on investment. Seasonally adjusted solar resource assessments (preferably combined with on-site measurement campaigns) can provide a higher element of certainty.

1.2.7 Scalability

PV power plants offer an almost unlimited scalability. The smallest energy generator would be a module (of e.g. 200Wp) with micro inverter, bigger utility scale power plants exceed these smallest device a million times (>200MWp). The wide range of available inverters (micro, string and central) and their repetitive application permit almost every plant size desired, so that the scalability of PV power plants is limited mainly by the area available and the grid connection conditions.

1.2.8 Costs and Potential of Cost Reduction

The impressive cost reduction of PV modules already has been shown in section 1.2.5 and further significant cost reductions are expected in the next decades. Cost reductions will be mainly driven by in increasing economies of scale and technology improvements. Higher module efficiencies in turn reduce the area required and also mounting costs.

The Figure 1-17 shows the relative development of system costs for large systems (>100 kWp).
Figure 1-18: Relative system cost development for systems > 100 kW in the US and Europe (2016 = 100%); no soft costs, such as costs for permits or costs for financing, are included; source: ITRPV; eighth edition, March 2017

In addition, as equipment costs keep falling, balance of system costs and costs for operations and maintenance (O&M) will rise in importance as cost reduction drivers. Approach towards best practice levels will therefore play an important role in the future and even in new markets. Competitive pressures are driving down costs rapidly.

O&M expenditures vary depending on the applied technology (fixed vs. tracked mounting system, string inverter vs. central inverters), site-specific factors like used surface (mowing) or soiling (module cleaning), accessibility, wages and others. Hence, it is difficult to estimate average O&M costs. O&M costs for utility-scale plants in the United States for example have been reported to be between USD 10 and USD 18/kW per year (Lawrence Berkeley National Laboratory, 2015b; Fu, et al., 2015) and in some OECD markets, such as Germany and the United Kingdom, the O&M costs now account for 20-25% of the LCoE (STA, 2014; deea, 2016).

The operation and maintenance expenditures consist of fixed and variable costs and include the following items:

- Administration and management;
- O&M staff;
- Service contracts;
- Materials;
- Maintenance reserve account payments;
- PV module cleaning; and
- Greenkeeping.
The LCoE depends substantially on the plant size and local irradiance conditions. Apart from these factors local market conditions influence the costs. The variation will decrease with the maturing of the emerging markets, lower capital costs and the expansion of best practice solutions worldwide.

Figure 1-19 shows the LCoE of individual projects in the years 2010 to 2015 with the weighted average and the projected LCoE range till 2025.

**Figure 2.3** Evolution of average auction prices for solar PV, January 2010-February 2017

The projection of Figure 1-19 is in line with the recent power purchase agreement and tender results in Mexico and Dubai, where bids reached prices as low as USD 0.03/kWh, even if it has to be taken into account that those prices are not necessarily directly comparable with an LCoE calculation. An LCoE calculation is a cost and yield based discounting whereas a competitive tariff is determined based on detailed financial modelling with specific investment return targets.

### 1.2.9 Consumptions of Media

Depending on the technology applied for module cleaning, water may be needed for the cleaning process. However, dry cleaning technologies are available in the market, helping to reduce the consumption of additional media of the PV power plant to zero.

### 1.2.10 Efficiency

The efficiency of a PV plant can be determined by referring to different parameters:
• Performance Ratio - to assess the quality of the applied technology and design (PR depends on temperature but not on irradiation) [
• Capacity factor – utilization of available plant power – [
• Specific yield – Power output per installed DC power – [kWh/kWp]; and
• Space consumption - installed DC Power per hectar – [kWp/ha].

The results of the different parameters depend on various site and technology specific factors. Main site-specific factors are the geographical location and the meteorological parameters like irradiation and temperature. Technology specific factors are determined by component selection (fixed vs. tracking mounting system, efficiency of inverters, cable dimensioning) and plant design (row distance, module tilt, DC/AC ratio).

Capacity factor

PV capacity factors are determined primarily by the quality of the solar resource and whether single or two-axis tracking is used. Other less important factors are module technology and system design. Preliminary analysis suggests that the shift to higher irradiation locations and the effect of increased use of tracking seem to have outweighed other factors influencing the global weighted average capacity factor of new utility-scale solar PV, which is estimated to have risen by around one-fifth between 2010 and 2015 (see Figure 1-20).

![Figure 1-20: Global weighted average capacity factor for utility-scale systems, 2010-2015; source IRENA Renewable Cost Database](image)

1.2.11 Applicability Under Prevailing Climate Conditions

Temperature, irradiation, latitude, distance to the sea, air pollution and extreme weather events are the main parameters that have to be considered when selecting the components and determining the plant design.
Ambient temperature and altitude might have an important influence on the inverter and transformer performance, which is why an approval of the manufacturer for the site-specific conditions might be necessary. Corrosion is the main subject that has to be considered when a site is located close to the sea or near to agricultural or industrial used areas. It is advisable to conduct appropriate measurements and to ask for approval from the concerned manufacturers. Extreme weather conditions like for example sand storms might lead to an adjusted selection of components (e.g. IP code of inverters) or the adaption of O&M activities (soiling – module cleaning frequency).

1.2.12 Standalone Capabilities and Load Follow Capability

Power generation of PV plants directly depends on solar irradiation and therefore standalone applications are only feasible in combination with other technologies.

In recent years, hybrid solutions with diesel generators have reached commercial maturity without gaining big market share. This solution is mainly applied to reduce the operating costs of diesel generators that are used by industrial consumers in remote regions.

Apart from this application, 100% autonomy is only achievable with large battery systems and therefore only economically viable in remote regions, where a connection to the grid is very expensive.

PV systems, due to their flexible scalability, can be sized in such a way that they consider the consumption, but they have no load follow capability without adding an energy storage system.

Storage systems are currently still very capital intensive and the economic efficiency of a storage system to increase self-consumption (up to the achievement of complete autonomy) is to be examined in individual cases. For the next few years a significant reduction in the cost of storage systems is expected from technical development and mass production. First larger storage systems (e.g., Lithium-ion batteries, redox flow batteries) with storage capacities of over 1MWh have been built over the last years and a satisfactory market maturity is expected to be achieved over the next five to ten years.

1.2.13 Rooftop PV Systems

Rooftop systems are treated separately in this section because several framework conditions like project development, technical aspects and regulatory framework differ significantly from utility-scale ground-mounted PV systems.

Technical aspects

With rooftop systems, almost exclusively fixed installed mounting systems are used. There are mainly two categories to be distinguished:

- Inclined roof: The modules are installed parallel to the roof; and
- Flat roof: Modules are installed on an inclined triangular mounting structure to optimize the tilt.

There are sophisticated systems for both categories. At the same time, the following points are of particular importance in the case of rooftop systems:

- A structural analysis of the roof structure is necessary with consideration of the additional load of the PV system;
Consideration of the individual site conditions (e.g. avoidance of roof leakage by selection of appropriate systems and materials, shading situation by surrounding buildings and roof structures, cable routing);

- Lightning and fire protection;
- Modification of e.g. the building’s electrical interconnection infrastructure for integration of the PV system; and
- Consideration of maintenance requirements.

The scalability of PV systems applies also to rooftop systems typically ranging from less than 1 kWp to larger plants in the MW range. Moreover, rooftop systems have the advantage that no additional sealing of floors and no additional demand of land is required.

### Commercial aspects

Rooftop systems are often significantly more expensive than freestanding systems, especially due to the generally smaller plant size and individual design. For plants less than 10 kWp, a doubling or tripling of prices compared to a large-scale PV plant is not uncommon. Cost reductions are expected due to lower component costs and optimization in balance of system costs (see section 1.2.5). Nevertheless, cost reduction might be not as strong as in utility-scale ground-mounted systems, because individual solutions for each roof have to be found.

In the case of rooftop systems, the O&M costs depend to a considerable extent on the accessibility of the roof and the individual generator areas. Possibly, repairs on the roof must be taken into account but ground maintenance is not necessary instead.

### Standalone capabilities and load follow capability

The energy generated by rooftop systems can often be integrated well into the grid due to the small size of the installations. Furthermore, the systems can be designed in such a way that they consider the consumption in the building. The self-consumption of the generated energy can be increased by the use of storage systems. Like for larger PV plants a complete autonomy is only reachable with an additional storage system and considerable higher investment costs.

### Framework

In addition to some interesting advantages (no additional land consumption, proximity to the consumer, neither environmental nor social impacts), rooftop systems have several challenging aspects that have to be considered if a significant scale of energy supply shall be reached in short time.

The small-scale and individual design characteristic of rooftop installations make a fast and controlled expansion difficult. For each building, a separate site visit has to be carried out and individual features like statics, roof surface particularities, mounting structure selection have to be considered. Besides property, usage, roof access, house technology and grid connection requirements need to be clarified individually.

In order to analyse the general potential of rooftop installations in Libya a geospatial analysis directed by governmental planning could be commissioned. It should be noted that a guided and clearly controlled development only would be possible for state-owned buildings, but the majority of buildings is predominantly privately owned. An effective promotion on those buildings could be reached by a regulatory framework that supports the private investment of local entrepreneurs and citizens (e.g. subsidies, feed-in tariff).
1.3 Wind Power

Wind power is, amongst the RE technologies considered for this assignment, perhaps the best established and the one holding the longest operational record. Wind power has been deployed all over the world with strong presence in China, United States and European countries mostly Germany, Spain and Denmark.

Main historic manufacturers such as Siemens, Vestas and Enercon are still leading the market with important portions of the wind market while big players in the power industry such as GE and Siemens are now within the top list of manufacturers. Chinese manufacturers such as Goldwind are winning rapidly important portions of the global wind market.

The main trend in wind power generation is towards higher capacities, direct drive, higher hub heights and offshore applications.

This section deals with qualitative aspects of wind power technologies and aims to select those technologies most appropriate for the Libyan conditions.

1.3.1 Maturity of Technology - Track Record

Although there are innovative designs in the wind power sector, for the objectives of this assignment it is important to focus on technologies that are mature i.e. with sufficient successful operational track record of established designs offered by two or more manufacturers with sufficient warranties that mitigate manufacturing and performance defects likely to occur under the climatic conditions in some regions in Libya including high temperatures and sand content which eventually require temperature and sand protection packages in the WTGs.

The predominant Wind Turbine Generators (WTG) have clearly evolved into three bladed rotor machines of variable speed with optimum angle of its blades controlled by a pitch system, horizontal axis and upwind orientation by means of active yaw system. WTG electrical generators are activated either directly (direct drive) or by means of a gearbox. Other components such as blades and towers are made of glass polyester/glass epoxy and steel/concrete respectively.

Last developments of WTGs feature speed variability and adjustable rotor blades. Speed variability is applied by manufacturers with induction and synchronous generators and is the widest used configuration. Enercon and Goldwind are manufacturers using synchronous generators, single bearing and direct drive configurations, which are recently a trend amongst other manufacturers, however chiefly for offshore applications.

The majority of products in the market are equipped with induction generators and gearboxes. This market share will very likely go on for many years to come since although direct drive machines could achieve about 3% higher efficiency than those with gearbox, their manufacturing cost are considerable higher. It is important to monitor how new technological developments driven by offshore developments can lower direct drive configurations costs.

The wind energy converted by the WTG into electricity is proportional to the third power of the wind speed and a function of the rotor diameter that in turn determines the amount of flow converted into electrical energy. Since wind speed increases and turbulence decreases the higher the nacelle of a
WTG is installed, higher hub heights and large rotor diameters combined will convert the maximum amount possible of energy in the wind into electricity. These facts have led the industry towards higher hub heights between 90 and 120 meters and larger rotor diameters up to approximately 130 meters.

Depending on wind speed, turbulence and gust wind speeds the IEC classified different sites into classes. In this manner manufacturers, because the loads increase substantially with the wind speed, can customize their designs for the actual conditions. Class 2 and 3 are the more common and cover the most typical wind conditions for implementation with wind speeds between 7.5 and 8.5 m/s average. Class 1 indicates requirements of WTG with wind speeds higher than 8.5 m/s and class S denotes a class for special conditions.

Another improvement in order to standardize, optimize and reduce costs associated to manufacturing is the trend of manufacturers to establish platforms. Platforms allow for standardized pieces of equipment for a WTG i.e. rotors, nacelles and towers which can be combined easily according to the site conditions.

1.3.2 Applicability Under Prevailing Climate Conditions

It is important to consider the conditions of the foreseen area for installation of WTGs. High temperature and desert conditions may lead some manufacturers to exclude deliveries in these areas. In general, WTG are designed to operate in temperatures up to 40°C, this limit is given by the design of the cooling system. At temperatures near this limit, the power of the WTG could be reduced and at temperatures very close to the same limit, the WTG will be shut down. The WTG will start again when a temperature lower than the limit is reached, hence considerable curtailment on the energy produced by the WTGs is to be expected in very hot regions. High temperature packages can extend this limit up to 45 or 50°C but not all manufacturers offer this option.

Manufacturers like Vestas, Gamesa and GE have gained experience in hot areas by installing WTGs in high temperature areas in Morocco, Egypt and the US. While climate conditions in central and south of Libya are very hot, temperatures in the north appear to be more suitable for wind power applications and could be therefore the focus of further analyses. The WTG technologies so far described are suitable for implementation in Libya, however preferably not in the hottest areas of the country. Losses of energy due to high temperature will be dealt with in second step of this technology assessment.

1.3.3 Offshore

WTGs for offshore applications use the same technology as onshore WTGs. The main technological difference in offshore applications is the foundation. Foundations could be either of the floating type or on the sea bed (fixed-bottom type). Capacities of WTGs for offshore applications shall be large in order to compensate for the higher capital and O&M costs associated with the foundations and their location in the sea respectively. Offshore applications of WTGs, from the technology prospective, could be implemented in the case of Libya, however other factors such as planning restrictions due to specific studies required, complexity of construction and higher capital and operation costs will not favour them.

1.3.4 Small WTGs
WTGs in the capacity range of tens to hundred KW, i.e. small WTG, can deviate from the designs discussed above e.g. downwind orientation. In general, small WTG cannot be evaluated together with large WTG since their capital cost is considerably higher and their capacity factor lower than wind farms with several large WTGs. Moreover, efforts on planning and resource assessment for small WTGs are also considerably higher per kW installed. The main purpose of small WTGs is for decentralized applications, hybrid systems or minigrids. Such applications will be the subject of a separate discussion in section 1.4.

1.3.5 Market Outlook

This section deals chiefly with the most common designs in the industry (see above). Small WTGs or innovative designs still in the pilot or prototype stage and products that have not reached commercial stage are not part of this market outlook. For the effects of this document commercial stage means an established product with existing production line, track record of operation, sufficient warranties and sufficient competitors in its range for future tendering purposes.

Global installed wind generation capacity has increased largely and regularly during the last years with 371 GW and 434 GW in 2014 and 2015 respectively as shown in Figure 1-21 (including both onshore and offshore).

![World Total Installed Capacity [MW]](image)

**Figure 1-21: World installed wind power capacity, 1997-2015**

Latest data on wind market outlook during 2016 show an increase in installed capacity of about 52 GW, reaching a total wind installed capacity of 487 GW (see Figure 1-22). The increment of annual installed capacity, however, during 2016 was less than previous years as shown in Figure 1-23 with only a slight increase in the European market. China contributed with 23 GW to the total new installed capacity., whereas in the MENA region, more than 2 GW were added mainly in Morocco, Egypt, Tunisia and Jordan.

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9 WWEA, 2015a; IRENA, 2015b
10 GLOBAL WIND ENERGY COUNCIL, Global Wind Report, Annual Market Update 2016
By the end of 2016 the top five wind power countries were China (168,690 MW), the US (82,184 MW), Germany (50,018 MW), India (28,700 MW), Spain (23,074 MW), UK (14,543 MW), France (12,066 MW) and Canada (11,900 MW). Countries like Guatemala, Jordan and Serbia installed their first wind farm in 2015\(^1\).

Figure 1-22: Top ten cumulative capacity December 2016

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\(^1\) GLOBAL WIND ENERGY COUNCIL, Global Wind Report, Annual Market Update 2016
Despite the decrease of new annual installed capacity in 2016, installations in Libya neighbouring countries in the MENA region evidenced not only a growing market but also that the industry had gained experience by testing their products under similar climatic conditions. Some of the WTG manufacturers active in this region are Gamesa, Vestas and Nordex.

Egypt, as a neighbouring country to Libya, installed one of the largest wind farms in Africa with 100 WTGs and a total capacity of 200 MW reaching a total installed capacity of 810 MW by the end of 2015. In 2015 Ethiopia and Jordan added 153 and 117 MW reaching a total 324 and 119 MW wind installed capacity respectively. Morocco, Tunisia and Algeria also ended 2015 with 787, 245 and 10 MW respectively. In 2016 only South Africa added wind capacity in Africa and the Middle East.13

The Moroccan and Ethiopian pipelines for IPP implementation for the next five years are very important for establishing a market in the region. Moreover, Egypt may bring in an additional push for the wind market in the region in any moment due to the strong efforts being made to increase the renewable energy share in the generation fleet14. The outlook of the market for the next five years foresees that the trend of the wind market to grow will continue worldwide. Although not in the same scale of magnitude as for the large industrialized regions of the world, a steady increase of the cumulated wind power capacity is expected in Africa and the Middle East potentially led by South Africa, Egypt and Morocco (see Figure 1-24).

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12 GLOBAL WIND ENERGY COUNCIL, Global Wind Report, Annual Market Update 2016
13 GLOBAL WIND ENERGY COUNCIL, Global Wind Report, Annual Market Update 2015
14 GLOBAL WIND ENERGY COUNCIL, Global Wind Report, Annual Market Update 2015
Figure 1-24: Cumulative market forecast by region 2016-2020\textsuperscript{15}

The trend towards larger WTG capacities over the last two decades is still ongoing reinforced by the also growing offshore market. According to estimations of the Consultant the more common capacities for onshore WTGs in Europe are between 2 and 4 MW containing approximately 70\% of the market. Half of this percentage is of WTG capacities between 3 and 4 MW. Only approximately 7\% is going beyond the barrier of 4 MW with products from Siemens and Enercon\textsuperscript{16}.

During the last five years there has been a significant change in the top 15 of WTG manufacturers consolidating by the end of 2015 Chinese manufacturers in 8 positions of the top list and replacing Vestas as the leader (see Figure 1-25). The bulk of the Chinese production was delivered in their home market, while leading main European and American manufacturers such as Vestas, Enercon, GE, Gamesa and Siemens continued serving the international market.

\textsuperscript{15} GLOBAL WIND ENERGY COUNCIL, Global Wind Report, Annual Market Update 2015
\textsuperscript{16} Estimations of the Consultant based on Winpro wind turbines database developed by EMD International A/S
In 2015 offshore wind power saw an important increase of 3.4 GW added capacity in six main markets clearly led by the UK with 40% of the share, followed by Germany, Denmark, Belgium, Netherlands and Sweden. Although there are other countries starting their offshore implementations such as Japan, South Korea and the US, the associated higher cost and complexity will apparently not make offshore a very attractive option for countries like Libya within the short to medium term. The main suppliers of offshore WTGs in the European market are Siemens, MHI Vestas, Senvion and Adwen.\footnote{GLOBAL WIND ENERGY COUNCIL, Global Wind Report, Annual Market Update 2015.}

### 1.3.6 Technology Risks

This section focuses on risks related to the predominant technology discussed so far in this assessment as it can be considered mature, commercial and with sufficient suppliers for optimum competition in a PSP procurement process. Table 1-4 summarizes the main technological risks, their causes and mitigation measures.

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\footnote{Global wind market update, FTI Consulting, 2015}
<table>
<thead>
<tr>
<th>Technology risk</th>
<th>Cause</th>
<th>Mitigation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loss of availability</td>
<td>Bad selection of IEC class – Permanent damage of equipment or WTG derating</td>
<td>Careful data evaluation / proper measurement campaign</td>
</tr>
<tr>
<td></td>
<td>Failure of gear box (common in gearbox WTGs)</td>
<td>Include direct drive WTGs / Insurance / Warranties / Supplier requirements / O&amp;M requirements / Management of spare parts</td>
</tr>
<tr>
<td></td>
<td>Icing of components (blades)</td>
<td>Proper evaluation of climate conditions / De-icing systems</td>
</tr>
<tr>
<td></td>
<td>Overheating, explosion or fire</td>
<td>Proper evaluation of climate conditions / Requirements on design conditions</td>
</tr>
<tr>
<td></td>
<td>Component failure different to gearbox</td>
<td>Insurance / Warranties / Supplier requirements / O&amp;M requirements / Management of spare parts / Implementation of high temperature and/or dust packages</td>
</tr>
<tr>
<td></td>
<td>Low or inappropriate O&amp;M</td>
<td>Minimum requirements for O&amp;M / O&amp;M guarantees and penalties / Insurance</td>
</tr>
<tr>
<td>Construction delay or delay in start of commercial operation</td>
<td>Lack of clear requirement of grid code compliance during procurement process</td>
<td>Evaluate requirement during grid code preparation vis-à-vis WTG market. Include clear requirement for grid code compliance during preparation of procurement documents and evaluation of bids. Select technologies which are most suitable for the Libyan grid</td>
</tr>
<tr>
<td></td>
<td>Environmental compliance</td>
<td>Technical specifications in line with local environmental regulation</td>
</tr>
<tr>
<td></td>
<td>Obstacles by transportation of large components</td>
<td>Proper analysis of transportation options and good available data on transport infrastructure in the country</td>
</tr>
<tr>
<td></td>
<td>Lack of local machinery and equipment for erection of WTG</td>
<td>Investigate construction capabilities in the country</td>
</tr>
<tr>
<td></td>
<td>Delay of long-lead items</td>
<td>Proper supply contract / Insurance</td>
</tr>
<tr>
<td>Wind power curtailment and reduction of expected energy yield</td>
<td>Grid integration</td>
<td>Technical specification in line with grid requirements / Provisions in contract for curtailment due to grid events / Peak shaving / Implementation of storage</td>
</tr>
<tr>
<td></td>
<td>Dispatch</td>
<td>Implement state-of-the-art wind forecast if day ahead availability is required</td>
</tr>
<tr>
<td></td>
<td>Over estimation of wind resource</td>
<td>Perform a sound resource assessment and include uncertainties</td>
</tr>
<tr>
<td></td>
<td>Loss of availability due to high temperature and/or dust effects</td>
<td>Implementation of high temperature and/or dust packages</td>
</tr>
</tbody>
</table>
1.3.7 Scalability

Wind farms capacities are usually easy to scale up. Scalability of wind farms is limited mainly by the area available, environmental restrictions and grid connection conditions. An important effect of scaling up wind farms is that its efficiency is lower than that of a single WTG due to wake effects and is a function of the number of WTGs in the wind farm. These losses can be minimized by optimizing the spacing between WTGs. This effect will be considered in a later analysis when defining the technology configuration according to limitations of area and grid connection.

1.3.8 Costs and Potential of Cost Reduction

Onshore WTG costs fluctuate according to fluctuations of materials such as concrete and steel. Costs of WTG peaked in 2008 and 2009 due to those and other reasons, but costs have been decreasing since then to estimated levels between 950 and 1,240 USD/kW. This implies cost reductions of around 30 to 40% since 2009. WTG costs are likely to keep decreasing in the coming years driven mostly by larger sizes of WTGs, portfolio optimization, platform based production, reduced commodity prices and increased competition from Chinese manufacturers. Figure 1-26 shows the evolution of WTG prices between 1997 and 2016.

Figure 1-26: WTG prices in the United States, China and the BNEF wind turbine price index, 1997 - 2016

Total installed costs of onshore wind have also decreased substantially during the last years. In 2015 these costs were estimated to around 1,560 USD/kW, however they vary depending on the country, e.g. installed costs in China and India are substantially lower than those in Europe or USA. Drivers for

19 The Power to Change, Solar and Wind Cost Reduction Potential 2025, IRENA, June 2016
this cost reduction are economies of scale, greater competition between suppliers and technology innovation.

WTGs are the biggest portion of the installed cost of a wind farm with around 65% but achieving up to 84%. Towers represent in turn the biggest portion of the WTG cost. Figure 1-27 shows a typical installed capital cost breakdown for a wind power system.

![Wind farm cost breakdown](image)

**Figure 1-27: Capital cost breakdown for a typical onshore wind power system and turbine**

Average O&M costs for wind parks are difficult to estimate chiefly due to the different conditions in each country and the technological advances in the technology during the recent years, however a trend in the reduction of O&M costs has also been observed. Indicatively, for the case of Europe O&M costs may range from 1.5 to 2% of CAPEX or 0.02 to 0.03 USD/kWh per year.

Capacity factors of onshore wind farms have also improved in the recent years mainly due to higher hub heights, larger swept areas and better micro sitting. As an example, in the United States capacity factors are in a wide range between 18 and 54% being 35% the average.

Levelized Cost of Electricity (LCoE) will vary depending on the variation of the capacity factors and costs mentioned above. However, it could also be stated that these costs have reduced during the last years and there is a trend for this reduction to continue. The most attractive weighted average LCoEs were found in China and the United States with 0.05 and 0.06 USD/kWh respectively, while Europe achieved 0.07 USD/kWh. In Brazil and North America, certain projects reached LCoEs below 0.04 USD/kWh. A significant reduction in LCoE is expected mostly in South America driven by Brazil lower-cost wind farms.

Generation costs of offshore wind farms were still in 2015 around doubling those of onshore wind farms, however as technology improves, e.g. by implementing floating foundations and access to wind resources in deep waters, these costs can achieve further reductions.

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20 Renewable Energy Technologies: Cost Analysis Series, IRENA, June 2012
21 Global costs analysis -- the year offshore wind costs fell, Wind Power Monthly online, David Milborrow, 29 January 2016
1.3.9 Potential of Cost Reduction

Deployment of wind power is expected to double from 2014 again in 2020-2022 in a moderate scenario; an aggressive scenario will double it as soon as 2019. According to IRENA’s report the potential reduction of the costs of installed capacity of onshore wind is about 12% from 2014 to 2025. This reduction includes the effects of technological innovations such as:

- Larger WTGs;
- Advanced blades;
- Advanced towers;
- Improved WTG reliability and O&M practices;
- Lean supply chains and increased competition; and
- Wind farm best practices.

Introducing standardized turbine platforms for onshore WTGs has helped and will help achieving economies of scale during production subsequently reducing the cost of the WTG.

WTGs and towers are responsible for the biggest share of potential cost reduction until 2025 accounting to 27 and 29% of the total installed cost reduction respectively. Best practices of wind farm development by developers and regulators could bring about 25% of the potential cost reduction whereas economies of scale related to supply and manufacturing might contribute with 13%. Installed costs can fall from 1,560 USD/kW in 2015 to 1,370 USD/kW in 2025.

Potential of reduction of LCoE will benefit chiefly from improvements in capacity factors due to larger rotor diameters and better planning and micrositing of wind farms. Until 2025 LCoEs of onshore wind farms could be as low as 0.03 USD/kWh and as high as 0.09 USD/kWh (see Figure 1-28).

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22 The Power to Change, Solar and Wind Cost Reduction Potential 2025, IRENA, June 2016
1.3.10 Consumptions of Media

Wind farms only main supply is the wind. Different to solar energy which needs a minimum of water for washing and cleaning purposes wind power does not consume any additional media.

1.3.11 Standalone Capabilities

Standalone applications of wind power are mainly in the form of small WTGs and/or working in conjunction with other generation sources such as Diesel generators or PV panels. Wind farms consisting of typical WTGs in the order of MW are usually grid connected; the main advantage of wind power is bulk power generation at a negligible marginal cost. Depending on the generator type (e.g. doubly-fed and full converter types), wind turbines can perform black starts and provide reactive energy compensation capabilities.

1.3.12 Load-Follow Capability

Wind power applications have minimum to none load-follow capability without energy storage. Energy storage for wind power applications has not reached commercial status and it is still very capital intensive, hence, costs of storage will make the wind system very unattractive from the financial point of view.

The second step of this technology assessment will deal with supply profiles of wind according to the wind resource aiming to determine its viability in the RE mix. Meanwhile wind power is characterized as with very low load-follow capability.
1.4 Decentralized Generation with RE

RE implementation easily allows for the implementation of decentralized systems in areas with no or little interconnection with the main transmission or distribution systems. Usually decentralized RE are used to replace or reduce (fuel saver) the consumption of diesel generators due to higher procurement and transport cost of fuels.

These systems usually supply loads in the order of tens of kW to maybe a couple of MW such as those required in small villages, small islands, hotels or schools. Medium to large applications of RE in the order of many MW are usually connected to the main grid due to the amount of energy to be transported to other consume centres. Although it is possible to have a decentralized system in the medium to large capacities spectrum this is not considered in this assignment as it should be part of an overall strategy of the government for decentralization of electricity generation.

Decentralized systems are typically configured in different arrangements of PV, small WTGs, batteries and diesel generators, or a combination thereof i.e. hybrid systems. The selection of this configuration depends on the conditions of the site selected for installation.

Selection of the site for installation of a decentralized system follows a different approach than the one considered for this study. A typical procedure for such implementations is to perform a selection of technology alternatives for sites preliminarily defined by the Government on socio-economic grounds.

The Consultant assumes that areas not connected to the main network and not included in the expansion plans provided are not part of the demand outlook considered by GECOL. It is also assumed that these areas are supplied with electricity by means of a diesel generator set or similar. Should this generation be included in the LCEP the following information is required:

- Exact location with coordinates of the decentralized area;
- Current source of electricity supply;
- All demand relevant information including capacity, peak demand, load profiles and demand growth;
- Expected year of installation; and
- Expected availability of the system.

The Consultant can provide a recommendation on the system to cover the demand in that area and a very preliminary estimate of the associated costs. However, the LCEP will not be optimized for these systems as they are not “electrically” interacting with the technology configurations feeding directly into the grid.

Further decentralized systems which are autonomous in industries such as coal and oil exploitation should carry out their own internal studies in order to evaluate a transition to RE.

It is also important to highlight that appropriate regulation shall be put in place in order to install decentralized systems with either RE or with fossil fuels. In case this option is included in the LCEP coordination with other tasks are necessary for stage II the SREPL.
1.5 Hybridization

For the purpose of this assessment, combinations that occur either at the dispatch control and grid connection level or at the working fluid levels will be considered as commercial. These combinations are usually called hybridizations and for the purpose of this assessment, the same designation will be adopted. Solar and wind technologies discussed so far can be combined to feed electricity into the grid. Although theoretically these combinations can be designed in multiple configurations, at the level of medium to large capacities, only two of them have reached commercial levels. There are few examples worldwide of such applications from which actual data and experience is still to be shared within the industry.

1.5.1 CSP and Conventional Thermal Power Hybrid Systems

An important type of hybridization, is that of CSP and conventional thermal power generation. In this hybridization CSP can contribute with heat in the form of solar steam into a Rankine cycle. The heat can be injected into either a conventional boiler of a power plant or a Heat Recovery Steam Generator (HRSG) of a combined cycle. Solar share in these plants can be as low as necessary for preheating boiler feedwater or as high as necessary to reach a substantial share of MW in the electricity production of the ISCC. Technical limits of this share are mostly on the design and performance of the HRSG but around 20% electricity share from CSP can be given as an indicative value. Thermal storage configurations are not typically implemented for ISCC since their economic advantages are in conflict with the goals of the integration. This type of hybridization will not be further considered in this assessment as the majority of electricity is produced by fossil fuels.

1.5.2 CSP and PV Hybrid Systems

Current hybridization of CSP and PV plants occurs at the dispatch and grid connection level, i.e. after each technology has converted solar power into electricity. Examples of these cases are ongoing developments such as Middelt in Morocco, the Maktoum Solar Park in Dubai or Copiapó in Chile. This type of hybridization offers the flexibility of extending the solar production into the late evening and night by using the thermal storage of the CSP while producing mainly from the PV plant during the day. In this case, the CSP system produces electricity from stored thermal power after sunset till the late evening hours and the TES system is charged during the day without operating the steam turbine. This concept allows for demand orientated electricity production of solar systems as shown in Figure 1-29 below:
Apart from the peaker concepts, the CSP system could also produce electricity during the day e.g. in partial load operation, also to mitigate fluctuations of the PV electricity production. However, the preferred configuration would be the outcome of a techno-economic optimization of the technical concept in light of the respective boundary conditions. Such hybrid configuration can reduce the combined LCoE of both systems (PV+CSP) compared to a standalone CSP configuration due to relative low costs for the PV system, while having the advantage of the CSP dispatchability.

The PV+CSP hybrid systems offers a demand orientated electricity production which is essential for implementing high penetration of solar power into the existing energy sector. So far the TES of CSP is ahead of the battery storage systems for large utility scale PV power plants in terms of costs. Therefore, the PV+CSP hybrid can build the next phase of solar penetration in individual markets, following the initial phase with PV only.

Typically, the hybrid configurations might require the implementation of a higher tariff during the evening and night to incentivize both the implementation of CSP and the optimization of the plant. This configuration will be discussed for the technology configurations.

Figure 1-29: Exemplary daily production curve of a CSP and PV hybrid peaker concept
2. Technology Alternatives

The goal of the technology assessment in section 1 was to identify those PV, CSP and wind technologies most competitive for private sector participation implementation within the Libyan conditions out of the broad spectrum of solar and wind technologies currently available in the market. The Consultant has qualitatively reviewed aspects inherent to each technology and Libyan conditions across a logical method allowing the selection of suitable technologies for further analyses. Among others, aspects such as maturity of technology, market, technology risks, potential of cost reduction, scalability, grid support, resource and load profiles were analysed.

The basis for decision on the technology alternatives selected included chiefly:

- Sufficient maturity of technology with enough track record of successful installation and operation in recent years, thus ensuring a minimum level of reliability;
- Securing market competitiveness for PSP projects with sufficient quantity of suppliers and manufacturing capacities;
- Competitive CAPEX and OPEX and considerable potential for cost reduction;
- Load matching capabilities (whenever possible);
- Suitability for climatic conditions including resource available; and
- Minimum grid support for the levels of penetration considered.

CSP

Nowadays, parabolic trough plants are in routine commercial application, and solar tower systems are currently making the transition to commercial application, while the linear Fresnel and parabolic dishes are at the demonstration stage, and have not yet reached large-scale commercial application. The industry has shown a clear tendency towards either parabolic trough collector systems with thermal oil as HTF or solar tower systems with molten salt, both equipped with medium to large TES also based on molten salt.

The CSP technology with TES offers a demand orientated electricity production, which is essential for implementing high penetration of solar power into the existing energy sector. So far the TES of CSP is ahead of the battery storage systems for large utility scale PV power plants in terms of costs. Therefore, the CSP technology can build the next phase of solar penetration in individual markets, following the initial phase with PV only.

Putting this into perspective for the Libyan electricity sector, the implementation of CSP technology in Libya will be further analysed in different scenarios and sensitivities due to its higher technology cost and complexity compared to other renewable energies such as PV. However, to reach high penetration of solar power in the market, the dispatchable power generation capabilities of CSP systems becomes more important and therefore will be further analysed in the LCEP.

PV

Because of the good irradiation conditions, Libya offers an interesting framework to go for solar energy. The good scalability and the relatively simple nature of PV are important advantages of this technology. Referring to the applicability of the technology under the prevailing climate conditions it is important to mitigate functional risks especially regarding the inverter and mounting structure selection.
Fixed structures are the most reliable mounting option. As discussed within section 1.2.3 two-axis tracking systems have decisive disadvantages regarding reliability due to the number of moving parts. Their market share especially in utility-scale PV power plants is negligibly small. 1-axis tracking systems instead have reached a significant market share and meanwhile are widely deployed also in desert-like areas. Nevertheless, the newly developed systems still have to prove reliability for the lifetime of a PV power plant. The reduction in the LCoE makes the single-axis tracking system an interesting option and a further analysis is recommended if the additional risks are kept in mind.

A central inverter concept for PV power plants > 10 MW is recommendable. For smaller and/or more complicated sites string inverters are a good option.

Regarding the different module technologies, crystalline modules stand out concerning maturity, track record and market share. From the thin film PV modules, only First Solar as manufacturer of cadmium telluride (CdTe) modules has a significant market share. As Thin Film modules are less affected by high temperatures, thin film (CdTe) modules will not be excluded for PSP procurement, however crystalline modules will be the technology alternative for the LCEP as they are more representative of the market.

The application of energy storage systems for PV installations is still very capital intensive and an implementation of large-scale storage systems as a back-up for PV power plant is still uncommon. An extensive use will only be economically viable in the future.

**Rooftop PV systems**

Rooftop systems might be an interesting option for the long-term development of solar systems if the right regulatory framework can be set. The Consultant assumes that Libya will aim for an overall framework that will favour utility-scale PV projects that afford less administration efforts and can reach a noticeable share in energy production in short-term.

In addition to some interesting advantages (no additional land consumption, proximity to the consumer, neither environmental nor social impacts), rooftop systems have several challenging aspects that have to be considered if a significant scale of energy supply shall be reached in short time such as:

- The small-scale and individual design characteristic of rooftop installations make a fast and controlled expansion difficult. For each building, a separate site visit has to be carried out and individual features like statics, roof surface particularities, mounting structure selection have to be considered. Besides property, usage, roof access, house technology and grid connection requirements need to be clarified individually.
- In order to analyse the general potential of rooftop installations in Libya a geospatial analysis directed by governmental planning could be commissioned. It should be noted that a guided and clearly controlled development only would be possible for state-owned buildings, but the majority of buildings is predominantly privately owned. An effective promotion on those buildings could be reached by a regulatory framework that supports the private investment of local entrepreneurs and citizens (e.g. subsidies, feed-in tariff).

**Wind**

As a main conclusion the technologies proposed for further analyses are onshore three bladed rotor machines of variable speed with optimum angle of its blades controlled by a pitch system, horizontal axis, upwind orientation by means of active yaw system and equipped with electrical generators acti-
vated directly (direct drive) or by means of a gearbox. Towers made of steel/concrete are recommended.

Capacities of WTGs shall be 2 MW and above with hub height between 80 and 120 meters and rotor diameter between 90 and 120 meters.

Considering the Libyan grid stability and reliability aspects, type 1, 2 and 3 WTGs may not be recommended. Type 4 WTG is the most recommended as it will support the behaviour of the Libyan electric grid. However, type 4 still might have a limited number of suppliers mostly for the climatic conditions of Libya and therefore due to market conditions at least type 3 and type 4 are to be considered for procurement and competition purposes.

As discussed within this section these ranges of WTGs feature the most attractive installed costs and LCoEs not only currently but in the period considered for the LCEP. Further, this range of machines will include the top WTG manufacturers allowing for earlier optimization of future Private Sector Participation (PSP) procurement processes.

Technology risks associated to WTGs in this range can also be mitigated as the technology is mature and there is enough background in construction and operation, as well as risk allocation within the contract package.

**Offshore wind**

WTGs for offshore applications use the same technology as onshore WTGs. The main technological difference in offshore applications is the foundation. Foundations could be either of the floating type or on the seabed (fixed-bottom type). Capacities of WTGs for offshore applications shall be large in order to compensate for the higher capital and O&M costs associated with the foundations and their location in the sea respectively. Offshore applications of WTGs, from the technology prospective, could be implemented in the case of Libya, however other factors such as planning restrictions due to specific studies required, complexity of construction and higher capital and operation costs will not favour them.

Note that the Consultant limits the selection to onshore applications as offshore wind power is not only more capital intensive upfront but involves higher complexity and technological challenge for both the construction and operation of offshore windfarms.

**Small WTGs**

WTGs in the capacity range of tens to hundred KW, i.e. small WTG, can deviate from the designs discussed above e.g. downwind orientation. In general, small WTG cannot be evaluated together with large WTG since their capital cost is considerably higher and their capacity factor lower than wind farms with several large WTGs. Moreover, efforts on planning and resource assessment for small WTGs are also considerably higher per kW installed. The main purpose of small WTGs is for decentralized applications, hybrid systems or minigrids.

**Hybridization**

For the purpose of this assessment, combinations that occur either at the dispatch control and grid connection level or at the working fluid levels will be considered as commercial. These combinations are usually called hybridizations and for the purpose of this assessment, the same designation will be adopted. Solar and wind technologies discussed so far can be combined each other to feed electricity
into the grid. Although theoretically these combinations can be designed in multiple configurations, at the level of medium to large capacities, only two of them have reached commercial levels.

An important type of hybridization, is that of CSP and conventional thermal power generation. In this hybridization CSP can contribute with heat in the form of solar steam into a Rankine cycle. This type of hybridization will not be further considered in this assessment as the majority of electricity is produced by fossil fuels.

Current hybridization of CSP and PV plants occurs at the dispatch and grid connection level, i.e. after each technology has converted solar power into electricity. Examples of these cases are ongoing developments such as Middelt in Morocco, the Maktoum Solar Park in Dubai or Copiapó in Chile. This type of hybridization offers the flexibility of extending the solar production into the late evening and night by using the thermal storage of the CSP while producing mainly from the PV plant during the day. Such hybrid configuration can reduce the combined LCoE of both systems (PV+CSP) compared to a standalone CSP configuration due to relative low costs for the PV system, while having the advantage of the CSP dispatchability.

The PV+CSP hybrid systems offers a demand orientated electricity production which is essential for implementing high penetration of solar power into the existing energy sector. Therefore, the PV+CSP hybrid can build the next phase of solar penetration in individual markets, following the initial phase with PV only. Typically, the hybrid configurations might require the implementation of a higher tariff during the evening and night to incentivize both the implementation of CSP and the optimization of the plant.

A summary of the technology alternatives selected for further analyses is shown in Table 2-1.

### Table 2-1: Summary of technology alternatives for LCEP

<table>
<thead>
<tr>
<th>Technology</th>
<th>Alternative</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV</td>
<td>Crystalline / Thin film (CdTe)</td>
</tr>
<tr>
<td></td>
<td>Fixed mounted / One axis tracked</td>
</tr>
<tr>
<td></td>
<td>Central and string inverter configurations depending on the size</td>
</tr>
<tr>
<td>Wind</td>
<td>Upwind / 3 blades rotors / horizontal axis</td>
</tr>
<tr>
<td></td>
<td>Onshore</td>
</tr>
<tr>
<td></td>
<td>Hub heights: 80 – 120 m</td>
</tr>
<tr>
<td></td>
<td>Rotor diameters: 90 – 136 m</td>
</tr>
<tr>
<td></td>
<td>Site classification II and III</td>
</tr>
<tr>
<td></td>
<td>Direct drive / gearbox</td>
</tr>
<tr>
<td></td>
<td>Double Feed Induction Generator (DFIG) / Fully rated converter type (Type 3 and Type 4)</td>
</tr>
<tr>
<td>CSP</td>
<td>Parabolic trough with thermal oil as HTF and molten salt TES</td>
</tr>
<tr>
<td></td>
<td>Central Receiver Systems with molten salt as HTF and TES</td>
</tr>
<tr>
<td></td>
<td>Air cooled condenser system</td>
</tr>
</tbody>
</table>

These technology alternatives together with other information collected and findings from the overview of the role of RE in Libya, the resource and the definition of criteria for the LCEP will enable the Consultant to define the technology configurations for the LCEP in section 3. The technology configurations will be more defined solar and wind power plants which parameters will be estimated for optimization of the LCEP.
3. Technology Configurations

After having defined the technology alternatives for the LCEP in section 2, and in order to be able to estimate the inputs necessary for optimizing the LCEP, the Consultant will define a set of technology configurations.

The technology configurations shall be based on the technology alternatives and allow the LCEP to compare and select the least cost mix of solar and wind facilities while not neglecting the advantages of economies of scale and the disadvantages of RE fluctuation in matching the demand behaviour. Further, technology configurations shall have the following characteristics:

- Represent a range of products (e.g. thin film but not a particular brand thereof);
- Represent one technology alternative (e.g. molten salt solar tower with 12 h storage or 3 MW WTG);
- Provide a general representation of a technology with generic characteristics;
- May be optimized for certain parameters (e.g. row distance and tilt angle); and
- May be varied in operational characteristics.

The selection of the technology configurations is mainly a qualitative one since it is not possible to quantify values for the criteria for all possible configurations. However, aspects such as resource potential and grid connection points will indeed improve the selection of technology configurations (e.g. capacities available for connection at selected substations or proper DNI for charging a certain capacity of the TES for CSP technologies).

The number of technology configurations shall be small enough to allow proper functioning of the LCEP model. A number of ten (10) technology configurations are deemed suitable for the LCEP.

3.1 Technology Configurations - PV

According to the technology alternatives so far selected and the resource available in potential areas the Consultant, for the effects of the LCEP, has selected the following technology configurations for PV:

- Capacities 50 and 100 MW<sub>ac</sub> in order to capture the effects of economies of scale while installing capacities large enough to support the current supply gap in Libya;
- Combination of fix mounted and 1-axis tracked will also capture the gains on electricity yield Vs. higher OPEX costs by tracking in one axis; and
- Central inverter concept as recommended for the proposed capacities.

3.2 Technology Configurations - Wind

Due to the very good wind resource in some areas in Libya, as well as the state-of-the-art of wind technology, the Consultant proposes two wind technology configurations representing the current and future technology state-of-the-art. Capacities of 50 and 100 MW feature typical sizes for wind parks procurement in one IPP that also can deliver a competitive price for the MWh. The wind configurations for the LCEP are:
• 50 MW wind parks consisting of WTGs of about 2 MW each, 90 meters hub height and rotor diameters of 90 meters. This configuration will not only reflect the current status of onshore wind technology but also will allow for comparison with 50 MW PV parks; and
• 100 MW wind parks consisting of WTGs of about 3.5 MW, 110 to 120 meters hub heights and rotor diameters of about 120 meters. This configuration will allow appraising the full economic and technical advantages of technological developments in the near future displaying substantially improved capacity factors in locations with very good wind resource.

Wind farms are proposed mainly north of Libya in sites where the solar resource is optimum and ground data is available such as Aziziya, Dernah, Misurata and Al Maqron.

3.3 Technology Configurations - CSP

Currently CSP plants are featuring capacities above 100 MW combined with medium to large TES. It is important to mention that capacities of CSP plants are also somehow limited to certain commercial steam turbine capacities that will allow for competition and reasonable prices. Different to wind or PV, definition of the capacity of a CSP plant depends on the ranges of capacity of steam turbines available in the market. The Consultant has selected 100 MW capacities as this range of capacity will allow for both comparison with wind/PV capacities and selection of steam turbines capacities in the market.

For the purposes of the LCEP the Consultant will use capacities which allow for comparison with the wind and PV and therefore the following CSP technology configurations are defined:

• 100 MW parabolic trough with thermal oil as HTF and molten salt as TES;
• 100 MW central receiver system with molten salt as HTF and TES; and
• Air cooled condenser system.

Since recent auctions of CSP\(^2\) have demonstrated much more competitive prices for CSP electricity, the Consultant, together with the stakeholders, have explored different combinations of solar multiples and TES capacities which better reflect the market and set out the actual competitiveness of CSP. The follow combinations will be analysed as part of the LCEP for a fixed steam turbine generator capacity of 100 MW:

• Techno-economic optimization of the SM and the TES capacity for PT and CRS, resulting in TES capacities of 7 and 10 hours, for PTC and CRS respectively;
• TES and SM designed to deliver base load storage capacity in the night similar to the Fourth development phase of the Mohammed bin Rashid Al Maktoum Dubai design, resulting in TES capacities of 13 to 15 hours, for PTC and CRS respectively; and
• CSP peaker: A CSP plant that could deliver electricity only during peak times to compete with the simple cycle gas turbines (SCGT).

In order to assess preliminarily whether a CSP peaker could outpace the SCGT in the peak hours and gain a position in the LCEP mix, the Consultant has done some preliminary comparison of a CSP CR with 5 hours TES operating as a peaker and allowing electricity production only from storage and during evening peak hours, against a CSP CR base case with 10 hours TES and electricity production during the day and after sunset until the storage is empty. The indicative results in Table 3-1 below

\[^2\] Dubai Electricity and Water Authority (DEWA), Fourth development phase of the Mohammed bin Rashid Al Maktoum, 73 $/MWh. Source www.solarpaces.org
show, that a peaker concept for a CSP only configuration is much less attractive in terms of the cost of electricity production for such plant assuming 10% E-IRR.

Table 3-1: Preliminary price comparison of a CSP peaker option

<table>
<thead>
<tr>
<th>Peaker Concept Comparison</th>
<th>SM</th>
<th>TES</th>
<th>Capacity</th>
<th>Yield</th>
<th>CAPEX</th>
<th>Tariff</th>
</tr>
</thead>
<tbody>
<tr>
<td>CSP CR Base Case</td>
<td>3</td>
<td>10</td>
<td>100</td>
<td>494</td>
<td>637</td>
<td>135</td>
</tr>
<tr>
<td>CSP CR Peaker Concept</td>
<td>1.1</td>
<td>5</td>
<td>150</td>
<td>140</td>
<td>327</td>
<td>252</td>
</tr>
</tbody>
</table>

The CSP peaker concept might become advantageous when considered as a combined tariff together with other RE such as PV, however it will not be competitive enough to outpace a SCGT in the peak hours and therefore will not be further considered as a technology configuration.

3.4 Technology Configurations – Hybridizations

As previously discussed during the technology assessment there are currently two types of hybridization that could be further discussed for optimization of the LCEP. It is important to recall that a pre-selection of hybrid technologies is not based on the technical feasibility only, but aspects such as maturity of technology, competitive costs and sufficient suppliers for a tender procedure, play a major role in such selection.

The main advantage of a PV+CSP hybridization lies chiefly in engineering the dispatch and tariff during peak loads and such effects are not to be considered at this stage in the model but the least cost option only. Introducing a more attractive tariff during peak time to incentivize such hybrids can also be reflected with separate PV and CSP plants, Further, in order to be able to optimize the economics of PV+CSP more constraints are to be engineered in the design of the plant such as a minimum capacity of each technology or a range of share of PV on the overall capacity.

The Consultant proposes to run a scenario with only PV and CSP configurations to observe the combination of the technologies that it produces. From there it would be possible to make recommendations for the implementation of these hybrids in the SPREL from a tariff perspective.

The Integrated Solar Combined Cycle (ISCC) is a hybridization option that is currently found in the market in different configurations:

- Preheating of Heat Recovery Steam Generator (HRSG) feedwater of an existing Combined Cycle Gas Turbine (CCGT);
- Preheating of HRSG feedwater of a new CCGT; and
- Contribution of solar steam for power generation from a solar field or a central receiver system with direct steam generation.

The first two options involve relatively low shares of solar steam and are chiefly CCGTs. Furthermore, it is not recommended to hybridize an existing power plant due to the complexity and technical risks involved in modifying a complex thermal power plant. Therefore these two options will not be considered for further analyses but the last option which can offer higher shares of solar steam and hence a larger effect on the RE penetration.

The following considerations are important when considering ISCC configurations:
The solar portion of an ISCC will be only available when the CCGT portion is operating; there is little track record of ISCC in operation. Existing ISCC plants has relatively low solar shares of total capacity; TES are initially not recommended for ISCCs as the philosophy is that the conventional portion of the ISCC is intended to be dispatched; and solar shares are limited to about 25% of total capacity of the ISCC due to restrictions of the HRSG which will need large heat exchange surfaces when interrupting the supply of solar steam in the solar booster option (i.e. increasing the output of the ISCC with solar steam while maintaining the GT output) or reducing the exhaust heat of the GT while using solar steam in the fuel saver option (i.e. reducing the GT output and hence the fuel consumption while using solar steam).

From a practical point of view, the simulation of ISCC power plant involves substantially more effort and requires software capabilities that allow simulation of complex components such as SCGT and HRSG without mentioning the optimization process required for the share of solar energy in the integration.

Although this configuration is in accordance with the fuel saving rationale that is proposed for Libya, such an exercise will not only bring about additional effort but also requires substantial additional time due to the mentioned complexity in the simulation process.

For the reasons above at this stage the Consultant will not include the ISCC option in the LCEP in the same manner as for the RE sources. A way to preliminarily appraise the contribution of ISCC to the LCEP could be to reduce the fuel costs for a particular CCGT forcing higher utilization rates. This could be a way to indirectly determine potential fuel savings through implementation of ISCC that could be analysed as part of the LCEP final report.

### 3.5 Technology Configurations - Batteries

Further to the configurations above the implementation of batteries for the PV plants will be preliminarily analysed. As mentioned during the technology assessment, energy storage for PV plants could be economically viable in the future, however there is no certainty on the when and how much yet. For the purposes of the LCEP the Consultant will in any case incorporate a Long-Duration Energy Storage (LDS), i.e. one which is able to provide at least 7 hours of energy storage with a power of 10 MW, in one site in order to appraise its effects in the LCEP.

The Energy Storage System (ESS) selected for the simulation is a Li-Ion as it reacts quickly to changing supply-demand conditions, rides out quickly resource variations and has a predictable performance over a large number of charge-discharge cycles.

### 3.6 Summary of Technology Configurations

Table 3-2 shows the proposed technology configurations for estimation of LCEP criteria and optimization of the LCEP.
<table>
<thead>
<tr>
<th>RE</th>
<th>Technology Alternative</th>
<th>Technology Configuration</th>
</tr>
</thead>
</table>
| PV | • Crystalline / Thin film (CdTe)  
• Fixed mounted / One axis tracked  
• Central and string inverter configurations depending on the size  
• Li-Ion Long-duration Energy Storage (3 hours) | • 50 and 100 MW_{ac} fix mounted and 1-axis tracked with p-Si modules and central inverter;  
• One configuration crystalline fixed mounted of 50 MW_{ac} and 3 hours for the site in Sebah for comparison purposes |
| Wind | • Upwind / 3 blades rotors / horizontal axis  
• Onshore  
• Hub heights: 80 – 120 m  
• Rotor diameters: 90 – 136 m  
• Site classification II and III  
• Direct drive / gearbox  
• Double Feed Induction Generator (DFIG) / Fully rated converter type (Type 3 and Type 4) | • 50 MW wind park; 2 MW turbines, 90 m hub height, 90 m diameter;  
• 100 MW wind park; 3.5 MW turbines; 110/120 m hub height; approx. 120 m diameter. |
| CSP | • Parabolic trough with thermal oil as HTF and molten salt TES  
• Central Receiver Systems with molten salt as HTF and TES  
• Air cooled condenser system | • 100 MW_{gross} PT and Molten Salt tower with TES of 7 to 10 FLH (techno-economic optimization of SM and TES capacity);  
• 100 MW_{gross} PT and molten salt tower with TES of 13 to 15 FLH (base load configuration) |
| Battery | • Li-Ion battery of Long-Duration energy Storage | • Li-Ion modules of 10 MW and 7 hours |