# Report 3: Cost Modeling

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**Abstract**

We present further work on our Trnsys modeling of a combined cycle Concentrated Solar Thermal power plant. This report concentrates on a costing model. We calculate a levelised cost of electricity, then check how that changes with various changes to the model. We obtain reasonable agreement with other similar costing models.

## 1 The model

This is the same as that presented in the second report, the 100 MW scaled up dual cycle plant with an air receiver, thermal concrete storage, and a dispatchable steam cycle based on storage. The plant parameters are shown in three tables starting at Table 1 on page 2. After we had a working cost model we adjusted the steam control strategy, heliostat field size and storage size to attempt to get the lowest levelised cost of electricity. Since we are working with a constant feed in tariff , there is no time of day advantage in trying to match the Eskom load curve (Figure 1 on page 3 for example). The only real way to lower the levelised cost of electricity for a fixed level of investment is to increase the GWh produced per year. Our initial control strategy was to start the steam cycle up at 4 in the afternoon to match Eskom's load curve, but we adjusted that during this study.

## 2 Plant Parameters

The parameters for the 100 MW nominal plant are shown in Table 1 on page 2, Table 2 on page 2 and Table 3 on page 2. The number of heliostats (4000) will probably be too large for a single tower, and a distributed tower system might be needed. There are other approaches[Fre09] , notably the Google funded company eSolar, which use smaller (1 $m^2$) mirrors and multiple towers which might lead to lower capital cost.

| | |
|---|---|
| Number heliostats | 4000 |
| Heliostat area each | 100 $m^2$ |
| Peak thermal power onto receiver | 278 MW |
| Combustion chamber exit temp | 1100 C |
| Combustion chamber air flow | 1500 ton/hr |
| compressor pressure | 15 bar |
| Peak power electric | 117 MW |
| Peak turbine shaft power | 280 MW |

Table 1: Solar Field and gas turbine Plant Parameters for 100 MW Plant

| | |
|---|---|
| Mass thermal concrete | 20,000 ton |
| Length | 100 m |
| Total cross section area pipes | 20 $m^2$ |
| Temp cold | 300 |
| Temp hot | 500 |
| Thermal Storage capacity | 1260 MW Thermal |

Table 2: Thermal Storage Plant Parameters for 100 MW Plant

| | |
|---|---|
| Hot side flow rate | 1500 ton/hr (peak 16h to 20h) 600 ton/hr (other) |
| Steam/water flow rate (peak) | 180 ton/hr |
| Preheater (heated with steam) HTC | 1860 MJ/hr.K |
| Economizer HTC | 4000 MJ/hr.K |
| Evaporator HTC | 5000 MJ/hr.K |
| Super heater HTC | 1860 MJ/hr.K |
| Steam turbine 1 | Pressure drop 100 bar-20 bar peak Elect 15.4 MW |
| Steam turbine 2 | Pressure drop 20 bar-5 bar peak Elect 9.5 MW |
| Steam turbine 3 | Pressure drop 5 bar-0.05 bar peak Elect 15.8 MW |
| Condenser | cool water inlet 20 ton/hr |

Table 3: Heat recovery steam generator and steam turbines for 100 MW Plant

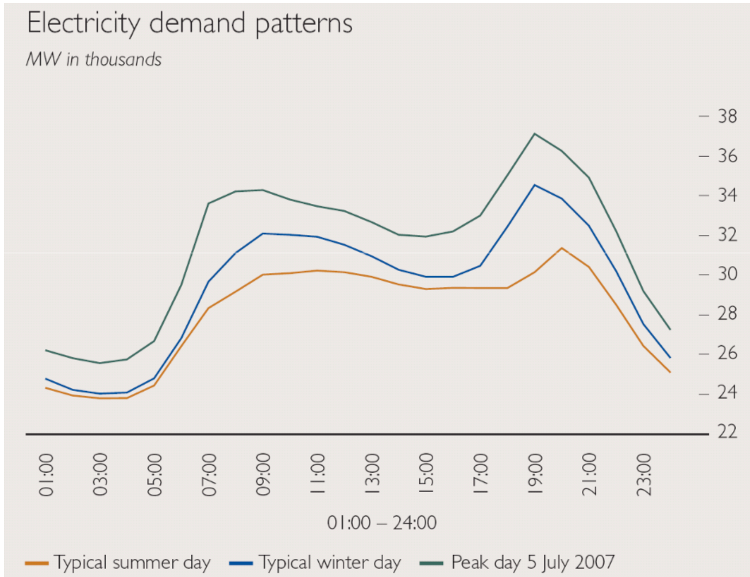


Figure 1: Eskom typical daily load curve

# 3 Costing

## 3.1 Assumptions

We obtained cost data from several previous publications, and usually tried to get more than one cost estimate for each component. We also checked how many towers we would need for a 100 MW plant. It seems from a Japanese study[UTY$^+$07] that optical spillage losses get too large when the radial distance of the heliostats exceeds 4x the tower height. If we assume a 100m tower height, then the maximal field size (assuming a semicircle on the South side of the tower) is 2.5 x$10^5$ m$^2$. Our total heliostat area is 4 x$10^5$ m$^2$, so we will need at least 4 towers (assuming a heliostat mirror area of 0.5 to land area). This mirror density seems a reasonable approximation from the Google earth picture of Solar Two as seen in Figure 2 on page 4.

The cost of various components in the plant are shown in the table 4 on page 5, together with the references for that component. Since some costs were calculated as long as 10 years ago, we have applied inflation and conversion factors as indicated in Table 5 on page 5. Sometimes we calculated item costs in a round about way: for example the steam turbine and generator component from the DOE study [DOE07] was calculated as follows: the cost of a conventional steam turbine plant was given as \$1300 per kWe, and the steam turbine and generator component was given as 15%. This gives us a cost of 195 \$/kWe and 139 €/kWe.

As another example where we got widely divergent answers, was the cost

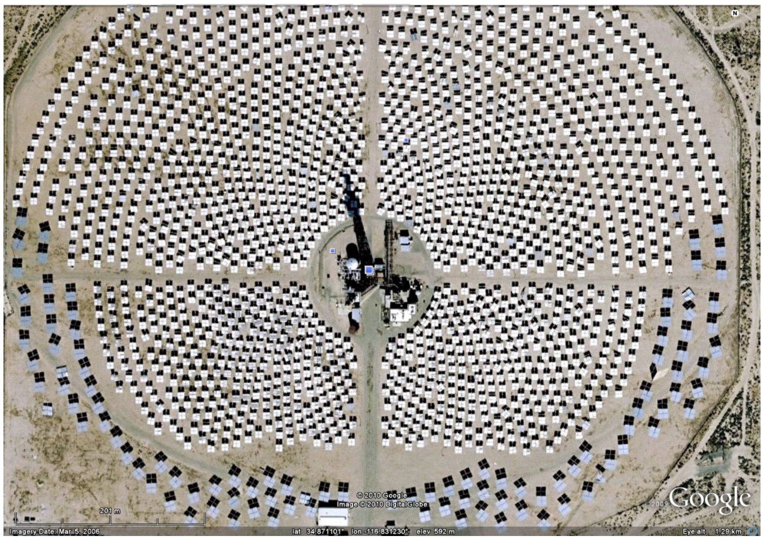


Figure 2: Solar Two Heliostat field, Dagget ,CA

of thermal storage. [PPDM05]gives this cost as 30 € per kWh Th, and if we calculate the thermal capacity of 20,000 tons of concrete, with a temperature rise of 200 degrees (from 300 to 500) as we charge and discharge, we get a thermal capacity of 1260 MW.h Thermal. This gives a cost of the thermal storage of 38 m € which seems quite high. We also calculated the raw cost of the concrete using a base cost of 75 $ us per cubic yard. This gives a cost of just the concrete of 600 k €. This is a factor of 50 different from the European calculation. However there is a heat exchanger made of steel pipes embedded into the concrete, and according to a German study performed in Spain [LSTR06] this makes up a significant proportion of the storage costs. Since several other studies give the costs of thermal storage in the same ballpark, we accepted the 30 € kW.h Th.

### 3.2 Levelised cost

Using the parameters mentioned above the capital costs worked out as shown in Table 6 on page 5

This plant produced an average of 80.6 MW over the whole year for a total annual power output of 706 GWh. Next we calculated operating costs using current prices of natural gas as a fuel, and estimating Operations and Maintenance as 10% of capital cost. We assumed an interest rate of 9% and a plant life of 25 years, as shown in Table 7 on page 5

With these assumptions, we arrived at an annual operating cost of 64 M € as shown in Table 8 on page 6. Here we calculated the levelised electricity cost as just the total running cost of the plant per year divided by the total num-

| Component | Cost | | Units | Ref | |
|---|---|---|---|---|---|
| | Min | Max | | Min | Max |
| Heliostat field | 114 | 150 | €/$m^2$ | [Wei00] | [PPDM05] |
| Receiver(s) | 150 | 165 | €/kW Th | [PPDM05] | [Wei00] |
| Tower(s) | | 2 m | €/tower | | [PPDM05] |
| Power Block Gas Turbine | 286 | 700 | €/kW El | [DOE07] | [PPDM05] |
| Power Block Steam (incl. turbine, pumps, condenser)) | 139 | 259 | €/kW El | [DOE07] | [Wei00] |
| Heat storage (thermal concrete) | 17.5 | 30 | €/kWh Th | [Fri04] | [PPDM05] |
| HRSG | 163 | 232 | €/kWh Th | [Wei00] | [DOE07] |
| Power Electronics | | 303 | €/kW El | | [Wei00] |

Table 4: Cost parameters of 100 MW Solar plant

| | |
|---|---|
| Conversion factor DM to € | 2 |
| Conversion factor $ to € | 1.4 |
| Conversion € to ZAR | 10.5 |
| Inflation over 10 years | 30% |

Table 5: Conversion factors and inflation

| SunSPOT | M€ | Percentage |
|---|---|---|
| Heliostat field | 60 | 18% |
| Receiver(s) | 42 | 13% |
| Tower(s) | 12 | 4% |
| Power Block (gas turbine) | 33 | 10% |
| Power Block steam, (incl. turbine, pumps, condenser) | 6 | 2% |
| Heat storage (Thermal concrete) | 38 | 11% |
| HRSG | 28 | 9% |
| Power Electronics | 48 | 14% |
| Total Capital Equipment | 267 | 80% |
| Land and Construction | 67 | 20% |
| Total Overall Capital Cost | 333 | |
| | | |
| Specific investment, €/W | 4.13 | |

Table 6: Actual cost of plant

| Component | Cost | Units | Reference |
|---|---|---|---|
| cost natural gas | 0.35 | €/kg | [DOE07] |
| Plant lifetime | 25 | years | [Wei00] |
| Interest rate | 9 | % | |
| Annual O & M | 10 | % of capital cost | [PPDM05] |

Table 7: Annual Operating cost assumptions

| Item | Cost M € |
|---|---|
| Fuel cost/year | 26.9 |
| O & M per year | 3.3 |
| Total running costs/year | 30.2 |
| interest rate | 9 |
| plant lifetime years | 25 |
| Total capital repayment/year | 33.9 |
| Total cost/year | 64.2 |
| | |
| Total levelised cost electricity | 0.091 €/kWh |

Table 8: Actual Operating Cost and Levelised Electricity cost

ber of kWh produced per year. This result compares favorably with estimates of similar power plants, and when converted to South African rands is 0.95 ZAR/kWh which is much lower than the NERSA REFIT feed in tariff of 2.1 ZAR/kWh., although the refit tariff is for a non hybrid plant without storage.

# 4 Optimizing for Lower cost of electricity

If we keep most of the plant parameters fixed, and we assume a constant electricity price throughout the day, then the only way to lower the cost of electricity is to produce more kilowatts with the same equipment. The involves either minor tweaks to some item of equipment, or else changes in control strategy. We tried two approaches, firstly adjusting the size and costs associated with the heliostat field, then adjusting the control strategy. here we tried two approaches, firstly adjusting the hot gas flow to the HSRG, and then also adjusting the gas burn time in the combustion chamber.

## 4.1 Adjusting Heliostat field size

We adjusted heliostat field size by just altering the size of each heliostat mirror from 90m$^2$ to 120 m$^2$. We found that as the heliostat field size increased, the plant produced slightly less power per year, but this was offset by a lower fuel requirement. The net result of this was that the levelised cost of electricity dropped slightly as the heliostat field size rose as shown in Table 9 on page 7. However the resulting change in the final cost of electricity was small, and this is not seen as an optimization worth pursuing vigorously.

| mirror size $m^2$ | Cost heliostats M € | GWh per Year | kTons fuel | Levelised Elec cents € |
|---|---|---|---|---|
| 90 | 54 | 708 | 80.5 | 9.18 |
| 100 | 60 | 706 | 76.1 | 9.08 |
| 110 | 66 | 703 | 71.7 | 8.98 |
| 120 | 72 | 701 | 67.3 | 8.88 |

Table 9: Effect of altering Heliostat field size

## 4.2 Adjusting control strategy

### 4.2.1 Steam Cycle run time

If we are not being rewarded by Eskom when we try and match their load curve, then we may as well only run our steam cycle at night, after the gas cycle has closed down. This will lower the cost of our power electronics and transmission facilities, as we then have to cope with lower peak power demands. So now we held our heliostat mirror sizes at 100 $m^2$, and moved our steam cycle to the evening, without altering the combustion chamber burn time. The standard model had the steam generator ramp up from 600 ton/hr (of air through the HSRG) to 1500 ton/hr from 15h00 to 16h00 , and ramp back down again to 600 ton/hr between 20h00 and 21h00. So our first attempt was to move this ramp up to 18h45 till 19h00 to match when the main gas turbine was winding down, and keep it at 1500 ton/hr for 4 hours till 23h00 and ramp down till 24h00. Again this did have an effect on the cost of electricity, but a very minor one (around 1%).

Another advantage of running the steam cycle at night is that this enables the more efficient use of air cooled condensers, as the desert night air temperature drops quite quickly. The plant would probably need air cooled condensers, as an air cooled plant uses only 10% of the water of a water cooled plant, and water is likely to be in short supply in the regions where these plants will be built.

### 4.2.2 Running the steam cycle at full rate till depleted

During attempts to get a second calculation of the thermal capacity of the concrete thermal store, we altered the steam generator demand to start straight after the combustion chamber shut down, and run at full demand (1500 ton air /hr) till the next morning, just before the combustion chamber started up again. This had the effect of more quickly depleting the thermal store, but the net effect was that we produced less electricity (636 GWh/year) as opposed to 694 GWh/year when we ran the steam generator full steam for 5 hours and at reduced capacity (600 ton air /hr) for the rest of the time. Since the steam generator and turbine needs to be kept warm, this is probably a more practical approach, as well as producing more electricity.

| steam generator | ramp up | ramp down | Cost Power electronics M € | GWh per Year | Levelised Elec cents € |
|---|---|---|---|---|---|
| peak overlaps gas | 15h00->16h00 | 20h00 ->21h00 | 48 | 706 | 9.08 |
| peak at night | 18h45 ->19h00 | 23h00 ->24h00 | 42 | 694 | 9.12 |
| night full steam till morning, no day time steam | 18h45 ->19h00 | 05h00->05h25 | 35 | 636 | 9.81 |

Table 10: Altering the time when steam was produced

| combustion burn time | ramp up | ramp down | kTon fuel | GWh per Year | Levelised Elec cents € |
|---|---|---|---|---|---|
| normal | 05h45 ->06h00 | 18:75 ->19:00 | 76.1 | 694 | 8.99 |
| extra hour | 04h45 ->05h00 | 18:75 ->19:00 | 85.3 | 748 | 8.89 |
| extra hour + off peak steam up to 700 | 04h45 ->05h00 | 18:75 ->19:00 | 85.3 | 754 | 8.82 |

Table 11: Changing combustion chamber burn time

#### 4.2.3 Combustion Chamber Burn Time

The standard model that we settled on was having the main gas compressor ramp up from 05h45 to 06h00 and ramp down from 18:75 to 19:00. We need the combustion chamber to burn for a reasonable amount of time to provide enough heat to charge the storage for the steam cycle to run during the night without running out of steam. We now kept the steam generator running at night as shown in Table 10 on page 8, but with an off peak component. Firstly we just started the combustion chamber an hour earlier each morning. This gave an increase in annual power output, but also an increase in fuel burned, although the net effect was a slight lowering of electricity cost (around 2%). Obviously these figures would change with natural gas price changes.

After adding extra burn time, there was now more heat energy in the system, and we could increase the off peak steam demand to take advantage of this to generate more electricity. We increased the off peak air flow to the HRSG from 600 ton/hr to 700 ton hr, and obtained slightly more electricity and a lower levelised cost of 8.82 € Cents per kWh. Increasing the off peak air flow to 800 ton/hr caused the system to run out of steam during the winter nights, so the optimum is probably around 700 tons/hr

# 5 Conclusions and Suggestions for Further Work

We have constructed a cost model and combined it with our TRNSYS model of a combined cycle solar power plant to enable us to conduct what if scenarios of different control strategies, and the see their effect on the levelised cost of electricity. The model seems quite stable and does not change wildly with different control strategies tried thus far.

It would be useful to do more work with this model:

- Sensitivity of the levelised cost of electricity to various changes, notably interest rates and natural gas prices
- Further experimentation with burn time control strategies.

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