S9: Generation Life Cycle Cost - IRP 2010 Input Parameter

Parameter

Generation Life Cycle Cost (GLCC)

Parameter Value

New generation options:

Using EPRI costs as per final EPRI report.

	Pulverised Coal with FGD	Fluidised bed with FGD	Nuclear Areva EPR	OCGT	CCGT
Capacity, rated net	6X750MW	6X250MW	6X1600MW	114,7MW	711,3MW
Life of programme	30	30	60	30	30
Lead time	9	9	16	2	3
Load factors (%)	85%	85%	92%	10%	50%
Variable O&M (R/MWh)	44,4	99,1	95,2	0	0
Fixed O&M (R/kW/a)	455	365	-	70	148
Variable Fuel costs (R/GJ)	15	7,5	6,25	74,4	74,4
Fuel Energy Content, HHV, kJ/kg	19220	12500	3,900,000	39,3 MJ/SCM	39,3 MJ/SCM
Heat Rate, kJ/kWh, avg	9769	10081	10760	11926	7468
Overnight capital costs (R/kW)	17785	14965	26575	3955	5780
Phasing in capital spent (% per year) (* indicates commissioning year of 1st unit)	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%	3%, 3%, 7%, 7%, 8%, 8%, 8%, 8%, 8%, 8%, 8%, 8%*, 6%, 6%, 2%, 2%	90%, 10%	40%, 50%, 10%
Equivalent Avail	91,7	90,4	92-95	88,8	88,8
Maintenance	4,8	5,7	N/A	6,9	6,9
Unplanned outages	3,7	4,1	<2%	4,6	4,6
Water usage, l/MWh	229,1	33,3	6000 (sea)	19,8	12,8
Sorbent usage, kg/MWh	15,2	28,4	-	-	-
CO2 emissions (kg/MWh)	936,2	976,9	-	622	376
SOx emissions (kg/MWh)	0,45	0,19	-	0	0
NOx emissions (kg/MWh)	2,30	0,20	-	0,28	0,29
Hg (kg/MWh)	1,27E-06	0	-	0	0
Particulates (kg/MWh)	0,13	0,09	-	0	0
Fly ash (kg/MWh)	168,5	35,1	-	-	-
Bottom ash (kg/MWh)	3,32	140,53	-	-	-
Expected COD of 1st unit	2018	2016	2022	2013	2016
Annual build limits	-	-	1 unit every 18 months	-	2500MW after 2018

Note: The variable fuel costs for OCGT and CCGT are based on natural gas prices provided by iGas. The coal fuel costs are based on upper range estimates for green-field coal. As no escalation is added in for future fuel costs, it was deemed prudent to start at a higher end of the range.

	Wind	Concentrated PV	Forestry residue biomass	Municipal solid waste biomass	Pumped storage
Capacity, rated net	100X2MW	10MW	25MW	25MW	4X375MW
Life of programme	20	25	30	30	50
Lead time	3-6	2	3,5-4	3,5-4	8
Load factors (%)	29,1% (7,2m/s wind @ 80m)	26,8%	85%	85%	20%
Variable O&M (R/MWh)	0	0	31,1	38,2	4
Fixed O&M (R/kW/a)	266	502	972	2579	123

Variable Fuel costs (R/GJ)	-	-	19,5	0	-
Fuel Energy Content, HHV, kJ/kg	-	-	11760	11390	-
Heat Rate, kJ/kWh, avg	-	-	14185	18580	-
Overnight capital costs (R/kW)	14445	37225	33270	66900	7913
Phasing in capital spent (% per year) (* indicates commissioning year of 1st unit)	2,5%, 2,5%, 5%, 15%, 75%	10%, 90%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	3%, 16%, 17%, 21%, 20%, 14%, 7%, 2%*
Equivalent Avail	94-97	95	90	90	94
Maintenance	-	-	4	4	5
Unplanned outages	-	-	6	6	1
Water usage, l/MWh	-	-	210	200	-
Sorbent usage, kg/MWh	-	-	-	-	-
CO2 emissions (kg/MWh)	-	-	1287	1607	-
SOx emissions (kg/MWh)	-	-	0,78	0,56	-
NOx emissions (kg/MWh)	-	-	0,61	0,80	-
Hg (kg/MWh)	-	-	-	-	-
Particulates (kg/MWh)	-	-	0,16	0,28	-
Fly ash (kg/MWh)	-	-	24,2	1226	-
Bottom ash (kg/MWh)	-	-	6,1	3000	-
Expected COD of 1st unit	2013	2018	2014	2014	2018
Annual build limits	500MW in 2013,1000MW thereafter	100MW			

	Integrated Gasification Combined Cycle (IGCC)	CSP, parabolic trough, 3 hrs storage	CSP, parabolic trough, 6 hrs storage	CSP, parabolic trough, 9 hrs storage
Capacity, rated net	1288MW	125MW	125MW	125MW
Life of programme	30	30	30	30
Lead time	5	4	4	4
Load factors (%)	85%	31,2%	36,3%	43,7%
Variable O&M (R/MWh)	14,4	0	0	0
Fixed O&M (R/kW/a)	830	513	562	635
Variable Fuel costs (R/GJ)	15	-	-	-
Fuel Energy Content, HHV, kJ/kg	19220	-	-	-
Heat Rate, kJ/kWh, avg	9758	-	-	-
Overnight capital costs (R/kW)	24670	37425	43385	50910
Phasing in capital spent (% per year) (* indicates commissioning year of 1st unit)	5%, 18%, 35%, 32%*, 10%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
Equivalent Avail	85,7	95	95	95
Maintenance	4,7	-	-	-
Unplanned outages	10,1	-	-	-
Water usage, l/MWh	256,8	250	245	245
Sorbent usage, kg/MWh	-	-	-	-
CO2 emissions (kg/MWh)	857,1	-	-	-
SOx emissions (kg/MWh)	0,21	-	-	-
NOx emissions (kg/MWh)	0,01	-	-	-
Hg (kg/MWh)	-	-	-	-
Particulates (kg/MWh)	-	-	-	-
Fly ash (kg/MWh)	9,7	-	-	-
Bottom ash (kg/MWh)	79,8	-	-	-
Expected COD of 1st unit	2018	2018	2018	2018
Annual build limits		500MW	500MW	500MW

Co-generation as per table in Co-generation Input Parameter sheet.

Existing fleet:

	Capacity (MW)
Eskom	**40897**
Camden	1424
Grootvlei	760
Komati	202
Arnot	2220
Hendrina	1900
Kriel	2850
Duvha	3450
Matla	3450
Kendal	3840
Lethabo	3558
Matimba	3690
Tutuka	3510
Majuba	3843
Koeberg	1800
Gariep	360
VanderKloof	240
Drakensberg	1000
Palmiet	400
Acacia and Port Rex	342
Ankerlig and Gourikwa	2058
Non-Eskom	**2902**
TOTAL	**44157**

Committed new plant:

Year	Grootvlei (RTS)	Komati (RTS)	Medupi	Kusile	DoE OCGT IPP	Ingula	MTPPP 1	REFIT 1 Wind	REFIT 1 CSP	REFIT 1 Landfill	REFIT 1 Small hydro	Sere
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2010	380	303	0	0	0	0	0	0	0	0	0	0
2011	0	404	0	0	0	0	396	200	0	0	0	0
2012	0	0	722	0	0	0	0	200	0	75	25	100
2013	0	0	722	0	1020	333	0	300	100	0	25	0
2014	0	0	1444	0	0	999	0	0	100	0	0	0
2015	0	0	722	1446	0	0	0	0	0	0	0	0
2016	0	0	722	723	0	0	0	0	0	0	0	0
2017	0	0	0	1446	0	0	0	0	0	0	0	0
2018	0	0	0	723	0	0	0	0	0	0	0	0

IRP INPUT PARAMETERS

Rationale

The independent EPRI report provided generic costs for new generation capacity. These costs will be used for the modelling of all new, non-committed generation capacity.

The existing Eskom and non-Eskom fleet is included with parameters on Capacity, Availability Indicators, Operating costs, Fuel costs. The actual costs are not indicated here, but are used in the IRP model to determine dispatch at the existing power stations. The assumed decommissioning of the plant is also provided.

The Eskom new build programme is taken as a given, including Kusile, at the official commissioning dates. Scenarios will be determined including delays in the commissioning of the new build.

Learning curves will be consistently applied across the scenarios, excluding the Base Case. These curves will be determined based on existing reports include the NIMS data (US).

Responses to Public Inputs

Summary of specific comments	Response
There are concerns regarding the delivery of the committed Eskom (and IPP) projects according to stated deadlines, including the risk of not meeting DSM objectives. (CIC)	Noted. Scenarios will be developed to indicate the impacts from such delays which should inform alternative plans.
The existing CAPEX plan should not be included as a given, but changed to scenarios. (CJN!-WC)	IRP will be done with the current decisions included in the base, with scenarios on possible slippage of the new build.
Learning curves for renewable technologies should be considered (90x2030, CJN!-WC)	All technologies display some learning curve potential. These will be considered in the scenarios (but not the base case).
All costs should be considered, including (carbon) taxes, water and transport infrastructure, impacts on public health and environmental damage, long term costs of nuclear waste, costs of decommissioning, future fuel cost escalation (90x2030, CJN!-WC, Private-DK, Private-WB, SAWEA, SusActMov, Windlab Developments SA). Full cost accounting, from a cradle to grave perspective, must be followed (Energy Caucus)	Noted. Certain costs, such as infrastructure, externalities will be considered in the criteria assessment.
It is difficult to understand how these figures can be determined with modelling a separate discount rate, mix and all the other parameters. Surely this is an intermediate outcome of the IRP planning process. (ACMP)	Noted.
Life cycle costs should include decommissioning costs, which for some technologies could be significant. (CEF, Coega Development Corporation, CSP Developers, Windlab Developments SA)	Noted. However given the discount rates discussed over a long plant life the decommissioning costs would be discounted to a trivial amount.
Low discount rates should be used for this exercise of costing different generation mixes, together with different finance packages available to the different technologies. The levelised costs should also be calculated for cost and capacity estimates 5 and 10 years hence, and the resultant levilised costs for the different technologies compared. (CSP Developers)	Noted. The screening curves will provide an assessment of the impact of discount rates on levelised costs.
The choice of discount rate should be changed when computing Refit tariffs for renewables to better reflect private investment return aspirations. (CSP Developers)	Unless there are real risk differences between the technologies (which are being covered separately) different discount rates only indicate a transfer of risk between producers, consumers or taxpayers. From the perspective of the IRP this is inappropriate, but may be realised in commercial agreements thereafter.
Alternative values for CSP Central receiver (9hrs storage): total cost R50000/kW, lead time 3 years, capacity factor 55%. (CSP Developers)	Noted.
Consideration must be given to uncertainty in costs per technology. (DoE)	Noted. The risk calculation will include the variability of cost assumptions and the impact this has on the final outcomes of the IRP.
A consistent and accurate analysis of the cost of new generation is therefore important. CONE represents the full cost and includes investment cost, fix and variable O&M costs, fuel price and cost of CO_2 emission for new capacity. (EDF South Africa)	Noted. The IRP model considers all these cost elements, with the exception of CO_2 emissions which are considered in specific scenarios.
Coal fired projects must include a climate cost; nuclear projects	Noted.

	must include long term storage and handling costs. Benefits must be applied to distributed generation, particularly in remote area because of the reduction of transmission losses. (IES)	
	The Levelised Cost of Electricity approach does not take into account the risk profile attached to each technology, the significant long-term exposure to fuel price volatility and the economic and societal impact of each form of technology. The correlations between each of the different types of electricity generation play a significant role in determining the total risk and cost profile of the national generation portfolio. (MainstResPower, SAWEA)	Noted. These specific issues are covered under the risk analysis and externality considerations as part of the criteria assessment for each scenario.
	The long operational life of third generation nuclear generators (60 to 80 years) must be accounted for in calculations of life cycle costs, as opposed to the shorter life of a coal fired power station (nominally 30 years). (NECSA)	Noted. The plant life indicated in the EPRI report will be used for the generic options.
	Advanced Reactors should be considered as future nuclear options; especially regarding future participation in gas cooled fast reactor or other Gen IV programmes, even though these will not be part of the installed capacity for quite some time to come. (NIASA)	Noted. However the IRP is focussing on existing technologies with some proven capability.
	Studies based on European costs indicate nuclear is on par with natural gas, not 3,5 times more expensive as indicated in the fact sheet. (Private-AR)	Noted. The EPRI report provides a different assessment of the relative costs from that indicated in the original fact sheet.