Table 10. Emissions 2 scenario

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	23.52	-	290,540	206,850	341,505	252	-
2015	1988	0	0	0	0	0	0	0	0	1988	54101	44865	2594	27.98	23.48	-	300,425	244,060	327,011	259	-
2016	1355	0	0	0	0	0	0	0	0	1355	55456	45786	3007	29.63	24.52	-	310,243	280,709	326,392	264	-
2017	1446	0	0	0	0	0	0	0	0	1446	56902	47870	3420	28.01	22.54	-	320,751	314,878	330,861	272	-
2018	723	0	0	0	0	0	0	0	0	723	57625	49516	3420	25.01	19.82	-	332,381	346,282	341,701	286	-
2019	0	0	0	0	575	0	0	0	0	575	58200	51233	3420	21.72	16.80	-	344,726	378,773	346,414	296	2.44
2020	0	0	0	0	805	653	0	0	0	1458	59658	52719	3420	21.01	16.26	-	355,694	413,983	359,481	305	12.64
2021	-75	0	0	237	805	1023	0	0	0	1990	61648	54326	3420	21.10	16.49	-	365,826	451,041	369,552	313	20.96
2022	-1870	750	0	948	805	283	1600	0	0	2516	64164	55734	3420	22.65	16.12	-	375,033	497,317	360,838	315	49.55
2023	-2280	250	0	948	0	0	1600	1600	0	2118	66282	57097	3420	23.48	15.15	-	383,914	556,835	330,101	302	91.79
2024	-909	0	0	948	0	0	1600	1600	0	3239	69521	58340	3420	26.59	16.45	-	392,880	610,191	315,790	294	87.22
2025	-1520	0	0	711	0	0	1600	1600	0	2391	71912	60150	3420	26.76	15.10	-	404,358	660,475	277,549	275	85.71
2026	0	0	0	0	0	0	1600	1600	0	3200	75112	61770	3420	28.73	15.54	-	415,281	705,297	279,917	275	81.16
2027	0	0	0	474	115	0	1600	0	0	2189	77301	63404	3420	28.87	14.28	-	426,196	734,485	274,581	275	27.46
2028	-2850	750	1200	0	230	0	400	1600	0	1330	78631	64867	3420	27.96	13.31	-	436,761	778,629	252,124	275	100.25
2029	-1128	0	0	0	0	0	0	1600	750	1222	79853	66460	3420	26.67	12.41	-	445,888	813,912	241,916	272	73.16
2030	0	0	0	0	805	0	800	0	0	1605	81458	67809	3420	26.51	11.73	-	454,357	835,491	241,091	275	15.38

Emission constraint of 275 million tons per year applicable only from 2025; committed programme as per Base Case scenario; maximum wind 1600MW per year; EEDSM as per Eskom MYPD2 application, max 3420MW

Table 11. Emission 3 scenario

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	CSP	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	23.52	-	290,540	206,844	341,494	252	-
2015	1988	0	0	0	0	0	1600	0	0	3588	55701	44865	2594	31.77	24.70	-	300,425	259,821	324,217	254	23.94
2016	1355	0	0	0	0	0	1600	0	0	2955	58656	45786	3007	37.11	26.92	-	310,243	311,093	325,526	255	23.94
2017	1446	0	0	948	0	0	1600	0	1500	5494	64150	47870	3420	44.32	29.69	-	320,751	410,634	331,122	265	114.28
2018	723	0	0	948	0	0	1600	0	3125	6396	70546	49516	3420	53.04	33.12	-	332,381	551,328	320,855	261	205.57
2019	0	0	0	948	805	0	1600	0	3125	6478	77024	51233	3420	61.09	36.28	-	344,726	686,055	310,920	256	208.99
2020	0	0	0	948	805	1110	1600	0	3125	7588	84612	52719	3420	71.63	42.06	-	355,694	832,231	251,137	220	229.38
2021	-75	0	0	474	805	0	1600	0	375	3179	87791	54326	3420	72.46	41.36	-	365,826	910,046	248,837	220	51.45
2022	-1870	0	0	0	0	0	1600	1600	0	1330	89121	55734	3420	70.36	38.14	-	375,033	971,083	245,914	220	81.16
2023	-2280	0	0	0	0	0	200	1600	0	-480	88641	57097	3420	65.14	33.61	-	383,914	1,019,413	250,447	220	60.21
2024	-909	0	0	0	0	0	1600	0	0	691	89332	58340	3420	62.66	29.98	-	392,880	1,053,142	243,538	220	23.94
2025	-1520	0	0	0	0	0	0	1600	0	80	89412	60150	3420	57.61	26.07	-	404,358	1,093,535	238,351	220	57.22
2026	0	0	0	0	805	0	400	1600	0	2805	92217	61770	3420	58.04	26.90	-	415,281	1,134,046	242,436	220	66.62
2027	0	0	0	0	805	0	1400	0	0	2205	94422	63404	3420	57.41	25.59	-	426,196	1,162,091	228,833	220	24.36
2028	-2850	0	0	0	805	0	0	1600	0	-445	93977	64867	3420	52.94	21.95	-	436,761	1,195,990	218,252	220	60.63
2029	-1128	0	0	0	805	0	400	1600	0	1677	95654	66460	3420	51.74	21.13	2	445,888	1,229,179	216,538	220	66.62
2030	0	0	0	0	805	0	800	0	0	1605	97259	67809	3420	51.05	20.27	-	454,357	1,250,053	218,970	220	15.38

Emission constraint of 220 million tons per year applicable from 2020; committed programme as per Base Case scenario; maximum wind 1600MW per year; EEDSM as per Eskom MYPD2 application, max 3420MW

Table 12. Carbon tax scenario

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,144	336,986	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,480	349,508	243	-
2012	1425	0	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,943	350,347	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,796	348,884	252	-
2014	2543	0	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	23.52	-	290,540	206,991	342,094	252	-
2015	1988	0	0	0	0	0	0	0	0	1988	54101	44865	2594	27.98	23.48	-	300,425	244,286	325,753	258	-
2016	1355	0	0	0	0	0	0	0	0	1355	55456	45786	3007	29.63	24.52	-	310,243	281,090	325,941	262	-
2017	1446	0	0	0	0	0	0	0	0	1446	56902	47870	3420	28.01	22.54	-	320,751	315,275	331,571	271	-
2018	723	0	0	0	0	0	0	0	0	723	57625	49516	3420	25.01	19.82	-	332,381	346,875	342,090	284	-
2019	0	0	0	0	690	1110	0	0	0	1800	59425	51233	3420	24.29	19.29	-	344,726	389,131	332,002	288	23.32
2020	0	0	0	0	575	283	1600	0	0	2458	61883	52719	3420	25.53	18.53	-	355,694	431,146	342,493	294	28.81
2021	-75	0	0	0	460	283	1600	0	0	2268	64151	54326	3420	26.02	17.17	-	365,826	470,793	354,372	302	28.32
2022	-1870	0	0	0	805	0	1600	1600	0	2135	66286	55734	3420	26.71	16.08	-	375,033	529,377	336,477	293	84.57
2023	-2280	0	0	711	575	0	1600	1600	0	2206	68492	57097	3420	27.60	15.27	-	383,914	586,151	314,969	284	88.15
2024	-909	0	0	948	230	283	1600	0	0	2152	70644	58340	3420	28.63	14.64	-	392,880	621,666	313,255	286	33.41
2025	-1520	0	0	948	0	0	1600	1600	0	2628	73272	60150	3420	29.16	13.75	-	404,358	671,141	289,593	275	87.22
2026	0	0	0	0	0	0	1600	1600	0	3200	76472	61770	3420	31.06	14.23	-	415,281	715,339	283,735	271	81.16
2027	0	0	0	948	0	0	1600	0	0	2548	79020	63404	3420	31.74	13.59	0	426,196	743,944	287,897	275	30.00
2028	-2850	750	0	711	690	0	1600	1600	0	2501	81521	64867	3420	32.67	13.22	-	436,761	788,574	255,199	262	102.33
2029	-1128	250	0	0	230	0	1600	1600	0	2552	84073	66460	3420	33.37	12.72	1	445,888	826,849	238,257	254	86.70
2030	0	750	0	0	0	0	1600	0	0	2350	86423	67809	3420	34.22	12.35	0	454,357	852,377	238,561	260	37.64

Table 13. Balanced scenario

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	703	0	0	0	0	0	0	0	0	703	46247	40995	809	15.08	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	48848	42416	1310	18.83	16.10	-	283,914	168,999	350,208	253	-
2014	1821	0	0	0	0	0	200	0	0	2021	50869	43436	1966	22.66	23.68	-	290,540	209,286	341,515	251	2.99
2015	1264	0	0	0	0	0	400	0	0	1664	52533	44865	2594	24.28	23.93	-	300,425	250,426	324,482	257	5.98
2016	632	0	0	0	0	0	800	0	0	1432	53965	45786	3007	26.15	25.57	-	310,243	294,325	326,187	261	11.97
2017	2168	0	0	0	0	0	800	0	0	2968	56933	47870	3420	28.08	19.39	-	320,751	336,017	337,415	270	11.97
2018	723	0	0	0	0	0	800	0	0	1523	58456	49516	3420	26.81	18.86	-	332,381	374,208	343,296	280	11.97
2019	1446	0	0	0	0	0	800	0	0	2246	60702	51233	3420	26.96	16.71	-	344,726	411,135	337,736	287	11.97
2020	723	0	0	0	575	0	800	0	0	2098	62800	52719	3420	27.39	16.37	-	355,694	446,855	343,273	295	14.41
2021	-75	0	0	237	805	0	800	0	0	1767	64567	54326	3420	26.83	15.15	-	365,826	482,121	358,681	305	16.90
2022	-1870	250	0	948	805	1110	800	0	0	2043	66610	55734	3420	27.33	14.94	0	375,033	526,618	345,092	303	46.41
2023	-2280	0	0	711	805	566	800	1600	0	2202	68812	57097	3420	28.20	15.12	-	383,914	581,802	329,844	295	82.01
2024	-909	0	0	474	230	0	600	1600	0	1995	70807	58340	3420	28.93	15.41	-	392,880	629,275	315,583	288	70.20
2025	-1520	0	0	711	0	0	1600	1600	0	2391	73198	60150	3420	29.03	14.08	-	404,358	678,476	285,251	275	85.71
2026	0	0	0	0	0	0	400	1600	0	2000	75198	61770	3420	28.87	13.89	-	415,281	717,888	288,015	275	63.21
2027	0	0	0	948	230	0	1400	0	0	2578	77776	63404	3420	29.66	13.53	-	426,196	746,887	283,541	275	27.99
2028	-2850	750	0	0	0	0	0	1600	1500	1000	78776	64867	3420	28.20	12.48	-	436,761	791,663	258,267	274	102.79
2029	-1128	750	0	0	115	0	0	1600	750	2087	80863	66460	3420	28.27	12.94	-	445,888	829,800	240,756	272	87.34
2030	0	0	0	237	575	0	0	0	0	812	81675	67809	3420	26.85	11.86	-	454,357	848,906	241,943	275	3.95

As per "Emission 2" scenario with wind rollout of minimum 200MW in 2014; 400MW in 2015; 800MW from 2016 to 2023; maximum 1600MW per year throughout; Coal costs at R200/ton; LNG cost at R80/GJ, Import Coal with FGD.

Table 14. Revised Balanced scenario

	Committed build											New build options														
	RTS Capacity	Medupi	Kusile	Ingula	DOE OCGT IPP	Co-generation, own build	Wind	CSP	Landfill, hydro	Sere	Decommissioning	Coal (PF, FBC, Imports)	Co-generation, own build	Gas CCGT	OCGT	Import Hydro	Wind	Solar PV, CSP	Renewables (Wind, Solar CSP, Solar PV, Landfill, Biomass, etc.)	Nuclear Fleet	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Total CO2 emissions
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	MT
2010	380	0	0	0	0	260	0	0	0	0	0	0	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	237
2011	679	0	0	0	0	130	200	0	0	0	0	0	103	0	0	0	0	0	0	0	1112	45647	39956	494	15.67	243
2012	303	0	0	0	0	0	200	0	100	100	0	0	0	0	0	0	0	0	0	0	703	46350	40995	809	15.34	251
2013	101	722	0	333	1020	0	300	0	25	0	0	0	124	0	0	0	0	0	0	0	2625	48975	42416	1310	19.14	254
2014	0	722	0	999	0	0	0	100	0	0	0	0	426	0	0	0	200	0	0	0	2447	51422	43436	1966	24.00	253
2015	0	1444	0	0	0	0	0	100	0	0	-180	0	600	0	0	0	400	0	0	0	2364	53786	44865	2594	27.24	259
2016	0	722	0	0	0	0	0	0	0	0	-90	0	0	0	0	0	800	100	0	0	1532	55318	45786	3007	29.31	262
2017	0	722	1446	0	0	0	0	0	0	0	0	0	0	0	0	0	800	100	0	0	3068	58386	47870	3420	31.35	269
2018	0	0	723	0	0	0	0	0	0	0	0	0	0	0	0	0	800	100	0	0	1623	60009	49516	3420	30.18	279
2019	0	0	1446	0	0	0	0	0	0	0	0	0	0	474	0	0	800	100	0	0	2820	62829	51233	3420	31.41	284
2020	0	0	723	0	0	0	0	0	0	0	0	0	0	711	0	360	0	0	800	0	2594	65423	52719	3420	32.71	290
2021	0	0	0	0	0	0	0	0	0	0	-75	0	0	711	0	750	0	0	800	0	2186	67609	54326	3420	32.81	296
2022	0	0	0	0	0	0	0	0	0	0	-1870	0	0	0	805	1110	0	0	800	0	845	68454	55734	3420	30.85	296
2023	0	0	0	0	0	0	0	0	0	0	-2280	0	0	0	805	1129	0	0	800	1600	2054	70508	57097	3420	31.36	288
2024	0	0	0	0	0	0	0	0	0	0	-909	0	0	0	575	0	0	0	800	1600	2066	72574	58340	3420	32.14	281
2025	0	0	0	0	0	0	0	0	0	0	-1520	0	0	0	805	0	0	0	1400	1600	2285	74859	60150	3420	31.96	273
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600	1600	2200	77059	61770	3420	32.06	270
2027	0	0	0	0	0	0	0	0	0	0	0	750	0	0	805	0	0	0	1200	0	2755	79814	63404	3420	33.06	275
2028	0	0	0	0	0	0	0	0	0	0	-2850	2000	0	0	805	0	0	0	0	1600	1555	81369	64867	3420	32.42	264
2029	0	0	0	0	0	0	0	0	0	0	-1128	750	0	0	805	0	0	0	0	1600	2027	83396	66460	3420	32.29	260
2030	0	0	0	0	0	0	0	0	0	0	0	1500	0	0	345	0	0	0	0	0	1845	85241	67809	3420	32.39	269

As with Balanced Scenario, with the additional requirement of a solar programme of 100 MW in each year from 2016 to 2019 (and a delay in the REFIT solar capacity to 100 MW in each of 2014 and 2015); CCGT forced in from 2019 to 2021 to provide backup options; additional import hydro as per the Regional Development scenario; co-generation/own build options forced in from MTRMP.

APPENDIX B – MODIFICATIONS AFTER CONSULTATION PROCESS

B.1. A more complete response to the consultation process is contained in the Consultation Process Report, but a summary of the key points raised in the consultation process is provided below. The text in *italics* reflects the summarised comments from participants; non-italic text reflects the Department of Energy responses.

Economic impact issues

B.2. *A socio-economic impact study has not been concluded or released.* This is an important oversight but it is expected that a report on the impact of the IRP will follow in the next few months.

B.3. *There should be an alignment of the expected growth assumptions with the New Growth Path.* The expected growth assumptions are based on the forecast derived during 2010 before the New Growth Path was developed and therefore does not reflect it in detail, but a combination of efficiency improvements with greater economic growth may result in a similar electricity demand outcome. This may be revised in a future IRP iteration.

B.4. *The discount rates used in the modelling do not appropriately reflect social discount rates.* The modelling follows a prudent approach in line with international practice for IRP, looking at the appropriate discount rate for developing economies. National Treasury has signed off on the 8% real discount rate applied, as used by NERSA in the utility price application.

Demand side issues

B.5. *Price elasticity of demand should be considered in the energy forecast.* This is worthy of additional research and will be included in future iterations. Existing research in the country does not concur on an appropriate level of price elasticity.

B.6. *Energy efficiency demand side management (EEDSM) is not properly covered while there is greater potential not considered.* While it is appreciated that there may be greater potential, from a security of supply point of view a conservative view of EEDSM outcomes is preferred. A scenario to test the impact of greater rollout is included below.

B.7. *The choice of energy forecast on which to base the IRP is not appropriate.* The System Operator's moderate energy forecast was chosen for the modelling as this represented a fair estimate, especially in the view of a least regret approach, where the impact of over-estimation is less than that of under-estimation. A scenario on a lower forecast is included below.

B.8. *The potential for universal access is not covered.* The System Operator moderate energy forecast was based on an expectation that the current roll-out of prepaid metering would continue, used as a proxy for additional coverage being rolled out nationwide.

Supply side issues

B.9. *Technology learning rates are not covered in the modelling.* This oversight has been corrected in the new scenarios, with an assumed global capacity increase and learning rates as identified by the International Energy Agency and an independent consulting group.

B.10. *The risks and costs associated with nuclear power are under-estimated in the model.* The assumed nuclear capital costs have been increased by 40% in the new scenarios to cater for this potential issue.

B.11. *The modelling of biomass options is inappropriate.* The modelling has been corrected with a reduction in the cost of the feedstock for bagasse and the reduction in emission rates to zero.

B.12. *Crystalline silicon PV is not included as a technology option.* This has been corrected with a view to PV being established based on recent cost adjustments and future global roll-out of capacity.

B.13. *The renewable options should be further disaggregated, especially solar.* This has been done in the new scenarios and policy-adjusted IRP. The solar options now cover crystalline PV, thin-film PV and CSP separately.

B.14. *The costs used in the modelling do not cover externalities associated with specific technologies.* Identifying the externalities and associated costs should be the subject of future research for future iterations.

B.15. *Private participation in the industry is not covered.* The IRP does not speak to ownership of capacity since this determination is made by the Minister of Energy after promulgation and a feasibility study of capacity options to determine whether it should be built by Eskom or procured from private players.

Network issues

B.16. *Transmission and distribution costs are not included in the modelling.* These costs are not covered under the new scenarios as the forecasting is not disaggregated into local areas. The costs are not a significant part of the overall costs of supply, especially the transmission costs, and would not particularly skew the technology choices.

B.17. *Distributed generation is not accommodated in the modelling.* The potential benefit of distributed generation requires further analysis, especially against potential costs relating to local network faults and upgrading required to support decentralised generation.

B.18. *The opportunity for smart grids is not dealt with.* This is again a potential research item to investigate the benefits of smart grids in conjunction with decentralised and renewable generation.

Process issues

B.19. *The process for future revisions of the IRP is not clear.* A detailed mechanism or policy on revision should be explored and promulgated.

B.20. *There is a need for greater involvement of stakeholders in the decision-making in the IRP.* A permanent governance arrangement for the IRP should be instituted with a larger participation from civil society, business and labour.

B.21. *There should be consistency between the IRP and the Medium Term Risk plans.* This is an issue being addressed between the teams involved in the two projects, with known projects (with a high degree of certainty) from the medium-term risk assessment being included in the IRP.

B.22. *The implementation of the plan is not clear.* The rules and regulations for implementation – from NERSA and the Department of Energy – are being discussed and will be finalised shortly.

Modification of inputs

B.23. Learning rates on new technologies were introduced, impacting on the capital and operating and maintenance costs. The learning rates are expressed in terms of a percentage reduction in the costs for each doubling of global capacity for that technology. This implies an assumption on expected global capacity for these technologies for the period of the study. The assumption for the global capacity is indicated in Table 15 partly derived from International Energy Association scenarios.

Table 15. Assumed international installed capacity

International installed capacity (GW)				
Technology	2010	2020	2030	Learning rate
CPV	1	7	25	10%
CSP	1	148	337	10%
Wind (onshore)	120	562	830	7%
Biomass (electricity production)	60	275	370	5%
IGCC	4	40	120	3%
Nuclear	370	475	725	3%

Source: IEA Energy Technology Perspectives 2008 for learning rates; IEA road maps for CSP, Wind, Nuclear for global capacity expectations; remaining technologies assumed.

Table 16. Expected overnight capital costs

Overnight capital costs (R/kWp)					
Technology	Storage (hrs)	System size (MW)	2010	2020	2030
PV Crystalline	-	0.25	26462	12164	8854
	-	1	21421	9927	7253
	-	10	20805	9652	7056
PV Thin Film	-	0.25	23927	11447	8100
	-	1	19369	9342	6636
	-	10	18812	9082	6455
CPV	-	10	37225	26770	22060
CSP Parabolic Trough	0	125	27450	12843	11333
	3	125	37425	17510	15451
	6	125	43385	20298	17912
	9	125	50910	23819	21018
CSP Central Receiver	3	125	26910	12590	11110
	6	125	32190	15060	13290
	9	125	36225	16948	14955
	12	125	39025	18258	16111
	14	125	40200	18808	16597
Wind	-	200	14445	12289	11797
Biomass (bagasse)	-	52.5	21318	19047	18633
Biomass (MSW)	-	25	66900	59772	58474
Biomass (Forest Waste)	-	25	33270	29725	29080
IGCC	-	125	22325	20177	19226
Nuclear	-	1600	26575	26285	25801

Source: Calculations from external consultants for solar PV, but own calculations for remaining technologies based on IEA learning rates and assumptions on global capacity.
Note: Nuclear costs in this table are based on the original EPRI overnight capital costs for nuclear and do not reflect the adjustments discussed below.

B.24. The impacts of these learning rates are shown in Table 16 where technology capital costs are reducing over the period of the IRP.

B.25. Modifications to the initial costs for solar photovoltaic (PV) technologies were made (incorporating thin-film and crystalline silicon) based on work prepared by external consultants (The Boston Consulting Group) who provided a view on the recent changes in costs for PV as well as expected changes during the course of the IRP period).

B.26. Changes to biomass assumptions were made, reducing the cost of the feedstock for the bagasse option from R57/GJ to R19/GJ for bagasse (based on similar costs in the EPRI report) and changing the carbon emissions for these options to a net zero emission rating.

B.27. The capital costs for nuclear were increased by 40% to accommodate inputs from numerous sources that the EPRI costs under-estimated the capital costs for recent nuclear build experience. The costs for South African decommissioning and waste management were also not fully incorporated in the original EPRI cost estimates and this adjustment allowed some accounting for these important elements.

B.28. The "own-generation, co-generation" column from the Revised Balanced scenario were also formalised. This column was included outside the modelling process to reflect the commitments made by industrial consumers as part of the Medium Term Risk Mitigation Programme (MTRMP). These commitments have turned out to be more coal-fired own generation than co-generation and have now been modelled as such (committing a total of 1000 MW of FBC between 2014 and 2015). The smaller remaining co-generation and own-generation options are not included as the potential is uncertain at this stage. These own build projects will be included in the demand assumptions of future IRPs as it materialises, and the Minister of Energy could allow the construction of these options as per the Section 34 determination should it require incentives such as the Co-generation Feed-in Tariff (COFIT).

B.29. An "Adjusted Emission" scenario, based on the "Emission 2" scenario from the original set of scenarios, was created by incorporating the modified inputs from above.

Additional scenarios

B.30. Initially it was intended to include a no-nuclear scenario by forcing out the new nuclear fleet. However following the modifications of inputs as discussed above (specifically the learning rates for new technologies and higher nuclear capital costs) the cost-optimal output from the model for the Adjusted Emission scenario does not include any new nuclear capacity.

B.31. Based on the Adjusted Emission scenario, five new scenarios were developed:

B.31.1. A "High Efficiency" scenario with increased EEDSM (to 6298 MW, from 3420 MW in the Revised Balanced scenario);

B.31.2. A "Low Growth" scenario based on the expected demand as projected in the CSIR-Low forecast;

B.31.3. A "Risk Averse" scenario which limits imported energy (to zero coal-fired generation and 2500 MW capacity from imported hydro) and limits total renewable energy capacity (to 10000 MW from wind, 8000 MW from solar PV and 4000 MW from solar CSP);

B.31.4. A "Peak Oil" scenario including escalated prices for diesel (to R400/GJ from the R200/GJ used in the Revised Balanced scenario), gas (to R160/GJ from R80/GJ) and coal (to R600/ton from R200/ton);

B.31.5. An "Earlier Coal" scenario including additional coal (particularly fluidised bed combustion (FBC)) between 2019 and 2023, and allowing for an increase in the annual carbon-dioxide emission target from 2025 (from 275 million tons in the Revised Balanced scenario to 288 million tons).

Results of new scenarios

B.32. Figure 6. As discussed above the "Adjusted Emission" scenario has no new nuclear capacity, with a large wind rollout of 15,8 GW, a solar PV programme of 8,8 GW and a solar CSP rollout of 8,8 GW. The remainder is split between the imported hydro (3,3 GW), coal (6,2 GW of which 2,2 GW is imported energy), combined cycle gas turbines (4,2 GW) and open cycle gas turbines (8,2 GW).

B.33. By increasing the EEDSM programme in the "High Efficiency" scenario, the carbon emission target can be reached with fewer renewables. This would also mean that a lower target could be reached with the same renewable roll-out as in the "Adjusted Emission" (and reduced coal-fired capacity), depending on the policy preferences.

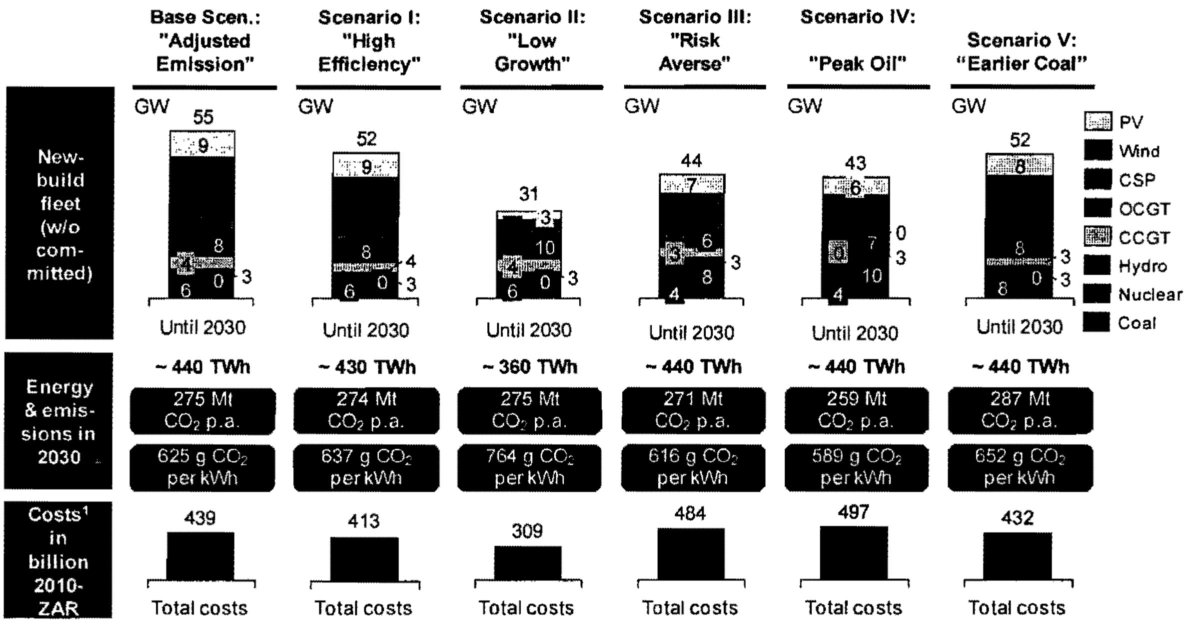
B.34. The "Low Growth" scenario resulted in very little renewable capacity being built due to the retained emission target of 275 million tons. A lower target would increase the renewable capacity at the expense of coal-fired generation.

B.35. Limiting the capacity from renewables and import options in the "Risk Averse" scenario shifts the emphasis to a nuclear programme (of 8 GW) as the next best option given the same emission target.

B.36. The increased cost of gas, coal and diesel in the "Peak Oil" scenario also leads to a nuclear programme (of 9,6 GW) and reduced capacity from renewable options. This may seem counter-intuitive but can be explained from Figure 7. The graph compares the combined levelised costs for a combination of solar PV and combined cycle gas turbines (CCGT) to the levelised costs for nuclear at different load factors. CCGT offers a back-up supply to PV in the hours where PV cannot produce (during the night or on heavily clouded days) and thus the combination provides a fully dispatchable alternative to nuclear. PV, on the other hand, works as a fuel saver for CCGT and thus reduces its fuel costs. The costs for the CCGT+PV option reduces over time due to learning rates (indicated by graphs for 2010, 2020 and 2030), while the nuclear option has two lines representing the original costs (in the Revised Balanced scenario) and the revised costs with a 40% increase in capital (in the Adjusted Emission scenario). Using the 2020 PV costs and adjusted nuclear costs, the graph indicates that a CCGT+PV combination would be preferred at a load factor of 65% or less (i.e. if the model does not require a large dispatchable capacity with high load factor), otherwise the nuclear would be preferred. In the "Peak Oil" scenario the costs relating to CCGT increases significantly, thus the dynamic represented in the graph would shift, with nuclear preferred across a broader range leading to the switch from renewable options to nuclear.

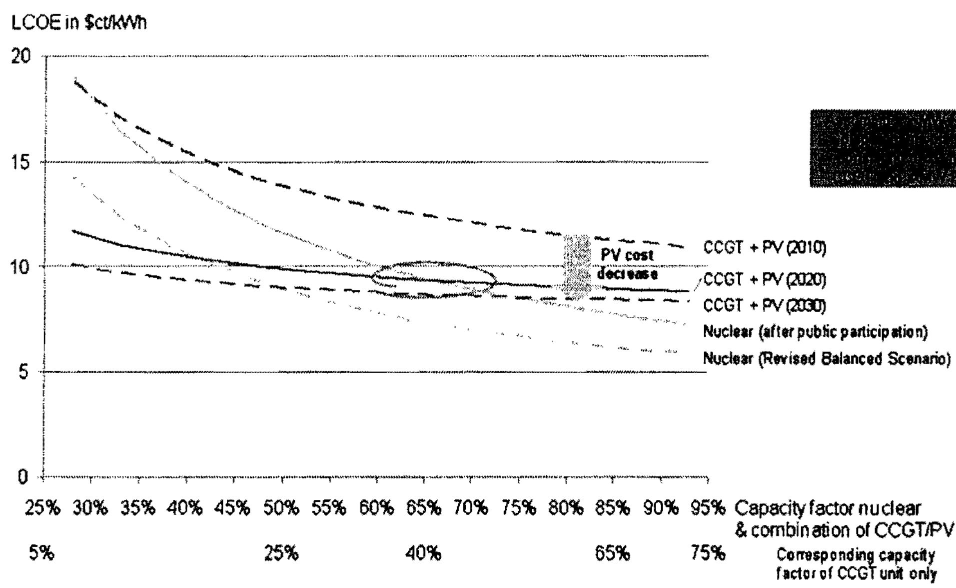
B.37. The "Earlier Coal" scenario results in a slightly larger coal programme displacing some renewable options, especially as the carbon emission target is increased to accommodate the larger coal programme (to 287 million tons per year from 2025).

Figure 6. Comparison of new scenarios



1. Present value, 8% discount rate; excluding existing fleet fixed costs and committed new builds; including variable costs for full fleet plus all new build costs
Source: Eskom IRP model

Figure 7. Comparison of levelised costs for nuclear and PV+CCGT combination



All assumptions according to the IRP; discount rate 8%; conversion rate of 1$ = 7.32 R (2010 average)
CCGT: system costs 5,780 R/kW, O&M 148 R/kW/yr; fuel price 74.4 R/GJ; efficiency 48%; economic lifetime 30 years; discount rate 8%
Solar PV: crystalline silicon-based system; system costs 2.89 $/Wp (2010), 1.34 $/Wp (2020), 0.98 $/Wp (2030); performance 2,000 kWh/kWp/yr; O&M 1%, 1.25%, 1.5% of initial CAPEX in 2010, 2020, 2030 respectively, economic lifetime 20 years; replacement of inverter in year 10
Nuclear: system costs 26,575 R/kW; O&M 95.2 R/MWh_el; fuel price 6.25 R/GJ; efficiency 33%; economic lifetime 60 years
Sources: Eskom IRP model; The Boston Consulting Group; BCG analysis

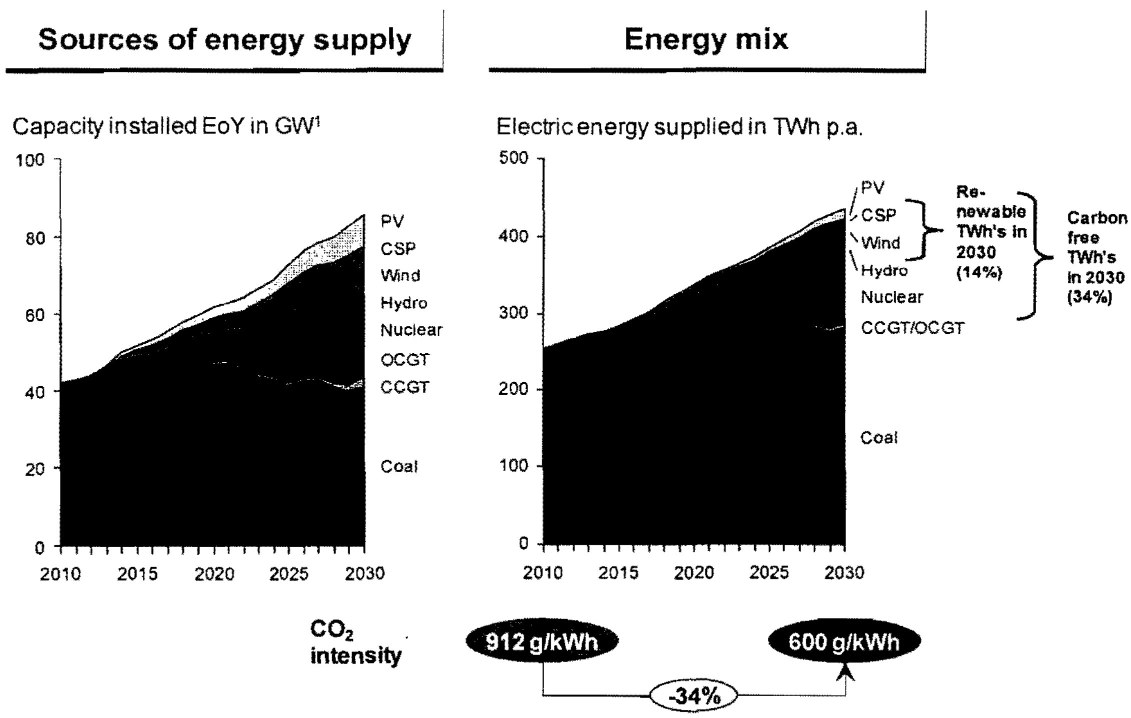
Table 17. Levelised costs in 2020 (based on learning rates)

		New build options										
		Coal (PF)	Nuclear	Solid waste	Biomass	Bagasse	Gas – CCGT	CSP	Pumped storage	Peak – OCGT	Wind	PV
Typical load factor →		85%	92%	85%	85%	50%	50%	40%	20%	10%	30%	20%
Fuel	R/MWh_{el}	147	67	0	277	377	597	0	~ 255[1]	2 385	0	0
Variable O&M	R/MWh_{el}	44	95	38	31	31	0	0	4	0	0	0
Fixed O&M	R/MWh_{el}	61	0	309	117	72	34	'10: 188 '20: 88	70	80	'10: 101 '20: 86	'10: 121 '20: 70
Capital	R/MWh_{el}	212	264 – 369	713	355	441	117	'10: 989 '20: 463	369	401	'10: 560 '20: 476	'10: 1186 '20: 560
LCOE	R/MWh_{el}	464	426 – 531[2]	1 061	779	867	748	'10:1178 '20: 551	698	2 866	'10: 661 '20: 562	'10:1307 '20: 630
CO_2	g/kWh	936	0	0	0	0	376	0	0 – 1 248	622	0	0

1. Assuming sum of fuel and variable O&M costs of coal power to stand for "fuel costs" of pumped storage
2. With and without 40% CAPEX increase

Zero if excess wind/PV power used as fuel. 1 248 g/kWh if coal power used as fuel

Figure 8. Capacity and energy mix 2010-2030



1. Pumped storage capacity of 1,4 GW in 2010 and 2,7 GW in 2030 is not included since it is a net energy user

Table 18. "Adjusted Emission" scenario

	Committed build											New build options																
	RTS Capacity	Medupi	Kusile	Ingula	DOE OCGT IPP	Co-generation, own build	Wind	CSP	Landfill, hydro	Sere	Decommissioning	Coal (PF, FBC, Imports)	Gas CCGT	OCGT	Import Hydro	Wind	Solar PV	Solar CSP	Nuclear Fleet	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	PV Total cost (cumulative)	Water	Total CO2 emissions
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	Rm	ML	MT
2010	380	0	0	0	0	260	0	0	0	0	0	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	44,138	336,420	237
2011	679	0	0	0	0	130	200	0	0	0	0	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	87,467	349,613	243
2012	303	722	0	0	0	0	200	0	100	100	0	0	0	0	0	0	300	0	0	1725	47269	40995	809	17.63	15.25	132,520	350,966	249
2013	101	722	0	333	1020	0	300	200	25	0	0	0	0	0	0	0	20	0	0	2721	49990	42416	1310	21.61	17.84	172,515	348,351	252
2014	0	1444	723	999	0	0	0	0	0	0	0	500	0	0	0	0	0	0	0	3666	53656	43436	1966	29.38	24.71	217,113	341,978	251
2015	0	722	723	0	0	0	0	0	0	0	-180	500	0	0	0	0	0	0	0	1765	55421	44865	2594	31.11	25.79	260,078	325,421	258
2016	0	722	723	0	0	0	0	0	0	0	-90	0	0	0	0	0	0	0	0	1355	56776	45786	3007	32.72	26.79	297,136	328,090	263
2017	0	0	1446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1446	58222	47870	3420	30.98	24.72	331,526	334,746	271
2018	0	0	723	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	723	58945	49516	3420	27.88	21.92	362,870	337,592	284
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	58945	51233	3420	23.28	17.67	394,196	339,864	294
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	0	0	0	0	805	59750	52719	3420	21.20	15.81	425,445	356,790	306
2021	0	0	0	0	0	0	0	0	0	0	-75	0	0	805	360	1400	0	0	0	2490	62240	54326	3420	22.26	15.21	463,189	367,190	314
2022	0	0	0	0	0	0	0	0	0	0	-1870	0	948	805	1523	1600	500	0	0	3506	65746	55734	3420	25.68	15.80	508,672	353,135	309
2023	0	0	0	0	0	0	0	0	0	0	-2280	600	474	805	1183	1600	1000	0	0	3382	69128	57097	3420	28.79	15.31	557,968	336,278	300
2024	0	0	0	0	0	0	0	0	0	0	-909	1100	237	115	283	1600	1000	1375	0	4801	73929	58340	3420	34.61	16.39	606,563	321,436	292
2025	0	0	0	0	0	0	0	0	0	0	-1520	500	474	805	0	1600	1000	3125	0	5984	79913	60150	3420	40.87	16.81	656,660	293,170	275
2026	0	0	0	0	0	0	0	0	0	0	0	0	237	805	0	1600	1000	1375	0	5017	84930	61770	3420	45.55	17.42	693,363	294,330	275
2027	0	0	0	0	0	0	0	0	0	0	0	500	0	805	0	1600	1000	1625	0	5530	90460	63404	3420	50.81	18.60	730,615	293,652	275
2028	0	0	0	0	0	0	0	0	0	0	-2850	1250	948	805	0	1600	1000	0	0	2753	93213	64867	3420	51.70	16.92	765,848	270,164	275
2029	0	0	0	0	0	0	0	0	0	0	-1128	1250	948	805	0	1600	1000	0	0	4475	97688	66460	3420	54.96	17.76	799,201	255,592	275
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	1600	1000	1250	0	4655	102343	67809	3420	58.95	18.32	827,155	256,994	275
	1463	4332	4338	1332	1020	390	700	200	125	100	-10902	6200	4266	8165	3349	15800	8820	8750	0	58448								

Emission constraint as per "Emission 2" scenario (275 million ton/year from 2025); FBC 500MW forced 2014, 15; maximum wind 1600MW per year; maximum solar PV 300MW per year until 2017, 1000MW per year thereafter; all international options incl (CO_2 emissions not counted in RSA); Medupi, Kusile and rest of committed plant as per "Emission 2" scenario (no delays)

Table 19. "High Efficiency" scenario

	Committed build											New build options																
	RTS Capacity	Medupi	Kusile	Ingula	DOE OCGT IPP	Co-generation, own build	Wind	CSP	Landfill, hydro	Sere	Decommissioning	Coal (PF, FBC, Imports)	Gas CCGT	OCGT	Import Hydro	Wind	Solar PV	Solar CSP	Nuclear Fleet	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	PV Total cost (cumulative)	Water	Total CO2 emissions
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	Rm	ML	MT
2010	380	0	0	0	0	260	0	0	0	0	0	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	44,138	336,420	237
2011	679	0	0	0	0	130	200	0	0	0	0	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	87,467	349,613	243
2012	303	722	0	0	0	0	200	0	100	100	0	0	0	0	0	0	300	0	0	1725	47269	40995	809	17.63	15.25	132,520	350,966	249
2013	101	722	0	333	1020	0	300	200	25	0	0	0	0	0	0	0	20	0	0	2721	49990	42416	1310	21.61	17.84	172,515	348,351	252
2014	0	1444	723	999	0	0	0	0	0	0	0	500	0	0	0	0	0	0	0	3666	53656	43436	1966	29.38	24.71	217,113	341,978	251
2015	0	722	723	0	0	0	0	0	0	0	-180	500	0	0	0	0	0	0	0	1765	55421	44865	3051	32.54	26.54	260,000	325,275	256
2016	0	722	723	0	0	0	0	0	0	0	-90	0	0	0	0	0	0	0	0	1355	56776	45786	4094	36.18	28.63	296,874	327,594	259
2017	0	0	1446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1446	58222	47870	5132	36.23	27.49	331,019	334,757	271
2018	0	0	723	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	723	58945	49516	5765	34.73	25.54	362,003	336,435	275
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	460	0	0	0	0	0	460	59405	51233	6221	31.98	22.66	393,657	330,669	284
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	0	0	0	0	805	60210	52719	6298	29.70	20.71	424,152	339,102	294
2021	0	0	0	0	0	0	0	0	0	0	-75	0	0	805	0	0	0	0	0	730	60940	54326	6298	26.88	18.32	453,498	358,753	307
2022	0	0	0	0	0	0	0	0	0	0	-1870	0	948	805	1110	1600	420	0	0	3013	63953	55734	6298	29.37	18.04	494,754	347,072	305
2023	0	0	0	0	0	0	0	0	0	0	-2280	600	711	805	1303	1600	810	0	0	3549	67502	57097	6298	32.88	18.15	543,508	328,680	296
2024	0	0	0	0	0	0	0	0	0	0	-909	600	0	690	370	1600	1000	0	0	3351	70853	58340	6298	36.15	17.80	583,506	321,990	293
2025	0	0	0	0	0	0	0	0	0	0	-1520	1000	0	0	566	1600	1000	3125	0	5771	76624	60150	6298	42.29	17.81	635,366	291,439	275
2026	0	0	0	0	0	0	0	0	0	0	0	0	237	690	0	1600	1000	1375	0	4902	81526	61770	6298	46.97	18.21	671,223	293,764	275
2027	0	0	0	0	0	0	0	0	0	0	0	500	237	805	0	1600	1000	1500	0	5642	87168	63404	6298	52.64	19.70	707,782	294,758	275
2028	0	0	0	0	0	0	0	0	0	0	-2850	1250	948	805	0	1600	1000	0	0	2753	89921	64867	6298	53.53	17.95	742,459	268,851	274
2029	0	0	0	0	0	0	0	0	0	0	-1128	1250	474	690	0	1600	1000	125	0	4011	93932	66460	6298	56.13	17.95	774,840	254,812	275
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	1600	1000	1375	0	4780	98712	67809	6298	60.48	18.62	802,620	256,026	274
	1463	4332	4338	1332	1020	390	700	200	125	100	-10902	6200	3555	8165	3349	14400	8550	7500	0	54817								

Emission constraint as per "Emission 2" scenario (275 million ton/year from 2025); FBC 500MW forced 2014, 15; maximum wind 1600MW per year; maximum solar PV 300MW per year until 2017, 1000MW per year thereafter; all international options incl (CO_2 emissions not counted in RSA); Committed plant as per "Emission 2" scenario (no delays); EEDSM increased to 6298MW (continuing from programme in "Adjusted Emission")

Table 20. "Low Growth" scenario

	Committed build											New build options																
	RTS Capacity	Medupi	Kusile	Ingula	DOE OCGT IPP	Co-generation, own build	Wind	CSP	Landfill, hydro	Sere	Decommissioning	Coal (PF, FBC, Imports)	Gas CCGT	OCGT	Import Hydro	Wind	Solar PV	Solar CSP	Nuclear Fleet	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	PV Total cost (cumulative)	Water	Total CO2 emissions
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	Rm	ML	MT
2010	380	0	0	0	0	260	0	0	0	0	0	0	0	0	0	0	0	0	0	640	44535	38573	252	16.21	16.11	43,969	335,452	235
2011	679	0	0	0	0	130	200	0	0	0	0	0	0	0	0	0	0	0	0	1009	45544	39314	494	17.32	16.64	86,913	346,722	239
2012	303	722	0	0	0	0	200	0	100	100	0	0	0	0	0	0	300	0	0	1725	47269	39911	809	20.89	18.43	131,403	346,382	242
2013	101	722	0	333	1020	0	300	200	25	0	0	0	0	0	0	0	20	0	0	2721	49990	41052	1310	25.79	21.84	170,684	343,039	244
2014	0	1444	723	999	0	0	0	0	0	0	0	500	0	0	0	0	0	0	0	3666	53656	41693	1966	35.06	30.08	214,720	341,693	249
2015	0	722	723	0	0	0	0	0	0	0	-180	500	0	0	0	0	0	0	0	1765	55421	42699	2594	38.19	32.42	257,024	324,905	253
2016	0	722	723	0	0	0	0	0	0	0	-90	0	0	0	0	0	0	0	0	1355	56776	43201	3007	41.25	34.71	293,352	327,560	258
2017	0	0	1446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1446	58222	44772	3420	40.80	33.75	327,001	328,247	266
2018	0	0	723	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	723	58945	45888	3420	38.80	32.00	357,460	336,362	274
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	0	0	0	0	805	59750	47038	3420	36.99	30.42	389,194	327,582	275
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	0	0	0	0	805	60555	48065	3420	35.64	29.26	418,753	328,589	275
2021	0	0	0	0	0	0	0	0	0	0	-75	0	0	805	0	0	0	0	0	730	61285	48940	3420	34.63	28.40	446,527	320,053	282
2022	0	0	0	0	0	0	0	0	0	0	-1870	0	711	805	0	0	570	0	0	216	61501	49722	3420	32.83	25.55	476,069	322,015	285
2023	0	0	0	0	0	0	0	0	0	0	-2280	0	948	805	1883	0	410	0	0	1766	63267	50440	3420	34.55	26.49	510,663	306,518	279
2024	0	0	0	0	0	0	0	0	0	0	-909	250	711	805	653	0	0	0	0	1510	64777	51137	3420	35.75	27.77	540,502	299,226	281
2025	0	0	0	0	0	0	0	0	0	0	-1520	600	948	805	813	0	50	0	0	1696	66473	52073	3420	36.63	28.67	571,649	285,109	275
2026	0	0	0	0	0	0	0	0	0	0	0	600	0	805	0	600	0	0	0	2005	68478	52920	3420	38.34	29.68	597,920	286,128	275
2027	0	0	0	0	0	0	0	0	0	0	0	500	237	805	0	1600	500	0	0	3642	72120	53748	3420	43.30	31.60	626,203	284,300	275
2028	0	0	0	0	0	0	0	0	0	0	-2850	2000	711	805	0	400	0	0	0	1066	73186	54536	3420	43.18	31.15	657,326	256,256	275
2029	0	0	0	0	0	0	0	0	0	0	-1128	1250	0	805	0	1000	200	0	0	2127	75313	55148	3420	45.59	32.00	683,794	245,334	275
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	800	990	0	0	2595	77908	55657	3420	49.14	32.74	703,567	243,572	275
	1463	4332	4338	1332	1020	390	700	200	125	100	-10902	6200	4266	9660	3349	4400	3040	0	0	34013								

Emission constraint as per "Emission 2" scenario (275 million ton/year from 2025); FBC 500MW forced 2014, 15; maximum wind 1600MW per year; maximum solar PV 300MW per year until 2017, 1000MW per year thereafter; all international options incl (CO2 emissions not counted in RSA); Committed plant as per "Emission 2" scenario (no delays); using CSIR-Low energy forecast

Table 20. "Low Growth" scenario

	Committed build											New build options																
	RTS Capacity	Medupi	Kusile	Ingula	DOE OCGT IPP	Co-generation, own build	Wind	CSP	Landfill, hydro	Sere	Decommissioning	Coal (PF, FBC, Imports)	Gas CCGT	OCGT	Import Hydro	Wind	Solar PV	Solar CSP	Nuclear Fleet	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	PV Total cost (cumulative)	Water	Total CO2 emissions
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	Rm	ML	MT
2010	380	0	0	0	0	260	0	0	0	0	0	0	0	0	0	0	0	0	0	640	44535	38573	252	16.21	16.11	43,969	335,452	235
2011	679	0	0	0	0	130	200	0	0	0	0	0	0	0	0	0	0	0	0	1009	45544	39314	494	17.32	16.64	86,913	346,722	239
2012	303	722	0	0	0	0	200	0	100	100	0	0	0	0	0	0	300	0	0	1725	47269	39911	809	20.89	18.43	131,403	346,382	242
2013	101	722	0	333	1020	0	300	200	25	0	0	0	0	0	0	0	20	0	0	2721	49990	41052	1310	25.79	21.84	170,684	343,039	244
2014	0	1444	723	999	0	0	0	0	0	0	0	500	0	0	0	0	0	0	0	3666	53656	41693	1966	35.06	30.08	214,720	341,693	249
2015	0	722	723	0	0	0	0	0	0	0	-180	500	0	0	0	0	0	0	0	1765	55421	42699	2594	38.19	32.42	257,024	324,905	253
2016	0	722	723	0	0	0	0	0	0	0	-90	0	0	0	0	0	0	0	0	1355	56776	43201	3007	41.25	34.71	293,352	327,560	258
2017	0	0	1446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1446	58222	44772	3420	40.80	33.75	327,001	328,247	266
2018	0	0	723	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	723	58945	45888	3420	38.80	32.00	357,460	336,362	274
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	0	0	0	0	805	59750	47038	3420	36.99	30.42	389,194	327,582	275
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	0	0	0	0	805	60555	48065	3420	35.64	29.26	418,753	328,589	275
2021	0	0	0	0	0	0	0	0	0	0	-75	0	0	805	0	0	0	0	0	730	61285	48940	3420	34.63	28.40	446,527	320,053	282
2022	0	0	0	0	0	0	0	0	0	0	-1870	0	711	805	0	0	570	0	0	216	61501	49722	3420	32.83	25.55	476,069	322,015	285
2023	0	0	0	0	0	0	0	0	0	0	-2280	0	948	805	1883	0	410	0	0	1766	63267	50440	3420	34.55	26.49	510,663	306,518	279
2024	0	0	0	0	0	0	0	0	0	0	-909	250	711	805	653	0	0	0	0	1510	64777	51137	3420	35.75	27.77	540,502	299,226	281
2025	0	0	0	0	0	0	0	0	0	0	-1520	600	948	805	813	0	50	0	0	1696	66473	52073	3420	36.63	28.67	571,649	285,109	275
2026	0	0	0	0	0	0	0	0	0	0	0	600	0	805	0	600	0	0	0	2005	68478	52920	3420	38.34	29.68	597,920	286,128	275
2027	0	0	0	0	0	0	0	0	0	0	0	500	237	805	0	1600	500	0	0	3642	72120	53748	3420	43.30	31.60	626,203	284,300	275
2028	0	0	0	0	0	0	0	0	0	0	-2850	2000	711	805	0	400	0	0	0	1066	73186	54536	3420	43.18	31.15	657,326	256,256	275
2029	0	0	0	0	0	0	0	0	0	0	-1128	1250	0	805	0	1000	200	0	0	2127	75313	55148	3420	45.59	32.00	683,794	245,334	275
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	800	990	0	0	2595	77908	55657	3420	49.14	32.74	703,567	243,572	275
	1463	4332	4338	1332	1020	390	700	200	125	100	-10902	6200	4266	9660	3349	4400	3040	0	0	34013								

Emission constraint as per "Emission 2" scenario (275 million ton/year from 2025); FBC 500MW forced 2014, 15; maximum wind 1600MW per year; maximum solar PV 300MW per year until 2017, 1000MW per year thereafter; all international options incl (CO2 emissions not counted in RSA); Committed plant as per "Emission 2" scenario (no delays); using CSIR-Low energy forecast

Table 22. "Peak Oil" scenario

	Committed build											New build options																
	RTS Capacity	Medupi	Kusile	Ingula	DOE OCGT IPP	Co-generation, own build	Wind	CSP	Landfill, hydro	Sere	Decommissioning	Coal (PF, FBC, Imports)	Gas CCGT	OCGT	Import Hydro	Wind	Solar PV	Solar CSP	Nuclear Fleet	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	PV Total cost (cumulative)	Water	Total CO2 emissions
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	Rm	ML	MT
2010	380	0	0	0	0	260	0	0	0	0	0	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	44,138	336,420	237
2011	679	0	0	0	0	130	200	0	0	0	0	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	87,467	349,613	243
2012	303	722	0	0	0	0	200	0	100	100	0	0	0	0	0	0	300	0	0	1725	47269	40995	809	17.63	15.25	132,520	350,966	249
2013	101	722	0	333	1020	0	300	200	25	0	0	0	0	0	0	0	20	0	0	2721	49990	42416	1310	21.61	17.84	172,515	348,351	252
2014	0	1444	723	999	0	0	0	0	0	0	0	500	0	0	0	0	0	0	0	3666	53656	43436	1966	29.38	24.71	217,171	341,978	251
2015	0	722	723	0	0	0	0	0	0	0	-180	500	0	0	0	0	0	0	0	1765	55421	44865	2594	31.11	25.79	260,242	325,421	258
2016	0	722	723	0	0	0	0	0	0	0	-90	0	0	0	0	0	0	0	0	1355	56776	45786	3007	32.72	26.79	297,399	328,090	263
2017	0	0	1446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1446	58222	47870	3420	30.98	24.72	331,880	334,746	271
2018	0	0	723	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	723	58945	49516	3420	27.88	21.92	363,308	337,592	284
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	58945	51233	3420	23.28	17.67	394,713	339,864	294
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	0	0	0	0	805	59750	52719	3420	21.20	15.81	426,084	360,091	307
2021	0	0	0	0	0	0	0	0	0	0	-75	0	0	805	860	0	40	0	0	1630	61380	54326	3420	20.57	15.29	458,487	368,435	316
2022	0	0	0	0	0	0	0	0	0	0	-1870	0	0	805	1303	400	0	0	1600	2238	63618	55734	3420	21.61	15.93	526,786	345,803	303
2023	0	0	0	0	0	0	0	0	0	0	-2280	0	0	805	1186	1600	500	0	1600	3411	67029	57097	3420	24.88	16.40	595,115	321,397	290
2024	0	0	0	0	0	0	0	0	0	0	-909	600	0	805	0	1600	500	0	0	2596	69625	58340	3420	26.77	15.65	632,255	317,379	290
2025	0	0	0	0	0	0	0	0	0	0	-1520	600	0	460	0	1600	500	0	1600	3240	72865	60150	3420	28.44	14.92	689,860	288,525	275
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1400	500	0	1600	3500	76365	61770	3420	30.87	15.26	739,056	287,246	271
2027	0	0	0	0	0	0	0	0	0	0	0	500	0	805	0	1600	920	0	0	3825	80190	63404	3420	33.69	15.17	769,254	286,699	275
2028	0	0	0	0	0	0	0	0	0	0	-2850	500	0	805	0	1600	1000	0	1600	2655	82845	64867	3420	34.82	13.42	816,825	258,094	264
2029	0	0	0	0	0	0	0	0	0	0	-1128	0	0	345	0	1600	1000	0	1600	3417	86262	66460	3420	36.84	12.71	858,681	242,670	255
2030	0	0	0	0	0	0	0	0	0	0	0	500	0	805	0	1600	1000	0	0	3905	90167	67809	3420	40.04	13.18	883,795	242,807	259
	1463	4332	4338	1332	1020	390	700	200	125	100	-10902	3700	0	7245	3349	13000	6280	0	9600	46272								

Emission constraint as per "Emission 2" scenario (275 million ton/year from 2025); FBC 500MW forced 2014, 15; maximum wind 1600MW per year; maximum solar PV 300MW per year until 2017, 1000MW per year thereafter; coal costs increased to R600/ton; LNG costs to R160/GJ; diesel costs to R400/GJ; Committed plant as per "Emission 2" scenario (no delays)

Table 23. "Earlier Coal" scenario

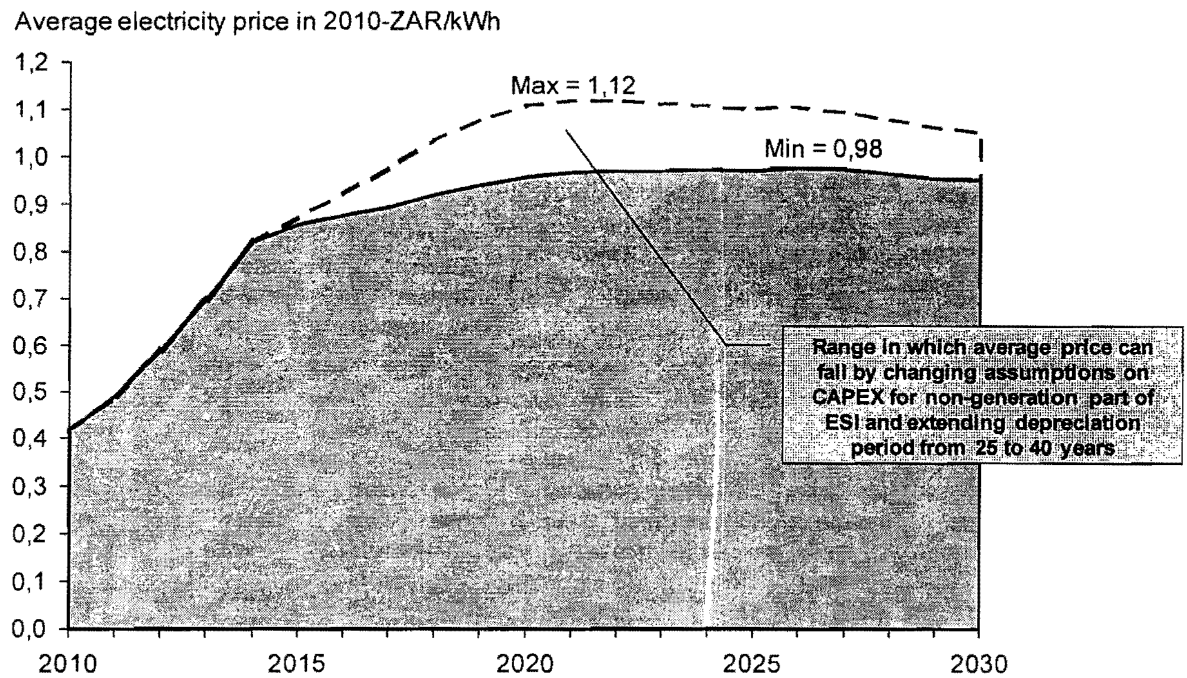
	Committed build											New build options																
	RTS Capacitry	Medupi	Kusile	Ingula	DOE OCGT IPP	Co-generation, own build	Wind	CSP	Landfill, hydro	Sere	Decommissioning	Coal (PF, FBC, Imports)	Gas CCGT	OCGT	Import Hydro	Wind	Solar PV	Solar CSP	Nuclear Fleet	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	PV Total cost (cumulative)	Water	Total CO2 emissions
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	Rm	ML	MT
2010	380	0	0	0	0	260	0	0	0	0	0	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	44,138	336,420	237
2011	679	0	0	0	0	130	200	0	0	0	0	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	87,467	349,613	243
2012	303	722	0	0	0	0	200	0	100	100	0	0	0	0	0	0	300	0	0	1725	47269	40995	809	17.63	15.25	132,520	350,966	249
2013	101	722	0	333	1020	0	300	200	25	0	0	0	0	0	0	0	20	0	0	2721	49990	42416	1310	21.61	17.84	172,515	348,351	252
2014	0	1444	723	999	0	0	0	0	0	0	0	500	0	0	0	0	0	0	0	3666	53656	43436	1966	29.38	24.71	217,113	341,978	251
2015	0	722	723	0	0	0	0	0	0	0	-180	500	0	0	0	0	0	0	0	1765	55421	44865	2594	31.11	25.79	260,078	325,421	258
2016	0	722	723	0	0	0	0	0	0	0	-90	0	0	0	0	0	0	0	0	1355	56776	45786	3007	32.72	26.79	297,136	328,090	263
2017	0	0	1446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1446	58222	47870	3420	30.98	24.72	331,526	334,746	271
2018	0	0	723	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	723	58945	49516	3420	27.88	21.92	370,310	337,592	284
2019	0	0	0	0	0	0	0	0	0	0	0	750	0	0	0	0	0	0	0	750	59695	51233	3420	24.85	19.19	408,524	335,015	294
2020	0	0	0	0	0	0	0	0	0	0	0	750	0	0	0	0	0	0	0	750	60445	52719	3420	22.61	17.18	444,553	341,272	305
2021	0	0	0	0	0	0	0	0	0	0	-75	750	0	805	0	0	0	0	0	1480	61925	54326	3420	21.64	16.41	474,666	349,440	317
2022	0	0	0	0	0	0	0	0	0	0	-1870	750	0	805	610	1600	0	0	0	1895	63820	55734	3420	22.00	14.89	514,034	338,972	319
2023	0	0	0	0	0	0	0	0	0	0	-2280	250	948	805	1273	1600	500	0	0	3096	66916	57097	3420	24.67	14.81	559,838	324,143	316
2024	0	0	0	0	0	0	0	0	0	0	-909	0	0	805	1183	1600	1000	0	0	3679	70595	58340	3420	28.54	15.13	602,115	318,853	314
2025	0	0	0	0	0	0	0	0	0	0	-1520	2200	0	345	0	1600	1000	2750	0	6375	76970	60150	3420	35.68	16.58	654,936	282,369	288
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	1600	1000	1375	0	4780	81750	61770	3420	40.10	16.80	690,986	284,349	288
2027	0	0	0	0	0	0	0	0	0	0	0	0	474	805	0	1600	1000	1625	0	5504	87254	63404	3420	45.46	17.96	726,064	285,395	288
2028	0	0	0	0	0	0	0	0	0	0	-2850	0	948	805	283	1600	1000	0	0	1786	89040	64867	3420	44.90	14.76	762,826	267,889	286
2029	0	0	0	0	0	0	0	0	0	0	-1128	1500	948	805	0	1600	1000	125	0	4850	93890	66460	3420	48.94	16.14	796,595	255,046	287
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	805	0	1600	1000	1250	0	4655	98545	67809	3420	53.05	16.73	824,487	256,143	287
	1463	4332	4338	1332	1020	390	700	200	125	100	-10902	7950	3318	7590	3349	14400	7820	7125	0	54650								

Emission constraint increased to 288 million ton/year from 2025; FBC 500MW forced 2014, 15, additional 3250MW FBC forced 2019 to 2023; maximum wind 1600MW per year; maximum solar PV 300MW per year until 2017, 1000MW per year thereafter; committed plant as per "Emission 2" scenario (no delays)

APPENDIX C - PRICING ISSUES

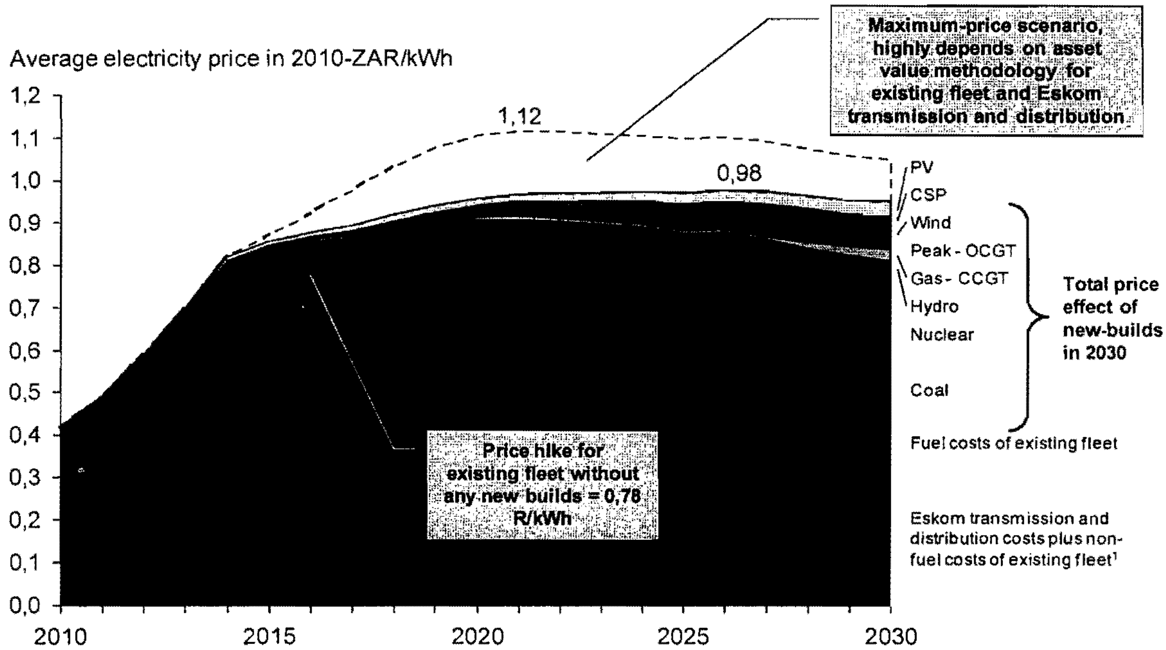
C.1. The Policy-Adjusted scenario results in a new expectation for future electricity prices, based on the different generation options being chosen. The Policy Adjusted plan results in a peak price of R1,12/kWh in 2021, relative to the R1,11/kWh in the Revised Balanced scenario. However after 2028 the Revised Balanced scenario price is higher than the Policy-Adjusted as the technology learning rates on new renewable options lead to lower costs. Figure 9 indicates the uncertainties in determining the price path. The R1,12/kWh peak is based on the assumptions as indicated in the draft IRP report. If some of these assumptions are relaxed, for example extending depreciation from 25 to 40 years, the price peak may decrease to R0,98/kWh.

Figure 9. Uncertainty in price path of Policy-Adjusted IRP



C.2. Much of the price increase expected to 2020 is based on the changes to asset valuation inherent in the regulatory rules applied by NERSA to Eskom's price application as well as capital expenditure required in Transmission and Distribution infrastructure.

Figure 10. Influence of technology choices on expected price path



1. Does not include costs of non-Eskom distribution network

APPENDIX D – REFERENCE INPUT TABLES

Table 24. Expected annual energy requirement 2010-34

	CSIR Low	CSIR Mod	CSIR High	SO Low	SO Mod	SO High
2010	249,051	249,422	249,626	257,601	259,685	261,769
2011	255,882	256,744	257,693	262,394	266,681	270,969
2012	261,031	262,376	263,682	267,784	274,403	281,022
2013	265,790	267,694	269,169	274,788	283,914	293,041
2014	270,630	272,964	274,497	278,880	290,540	302,201
2015	275,735	278,589	280,341	285,920	300,425	314,930
2016	281,051	284,450	286,545	292,728	310,243	327,758
2017	285,930	289,983	292,552	299,991	320,751	341,511
2018	290,870	295,628	298,548	308,036	332,381	356,725
2019	296,027	301,486	304,790	316,501	344,726	372,950
2020	301,255	307,503	311,226	323,498	355,694	387,891
2021	306,544	313,601	317,996	329,556	365,826	402,095
2022	311,934	319,869	324,928	334,587	375,033	415,480
2023	317,465	326,326	331,948	339,160	383,914	428,668
2024	323,104	332,998	339,306	343,634	392,880	442,126
2025	328,456	339,436	346,399	350,065	404,358	458,650
2026	333,733	345,864	353,525	355,785	415,281	474,777
2027	338,636	352,012	360,379	361,300	426,196	491,093
2028	343,651	358,365	367,618	366,319	436,761	507,204
2029	348,758	364,884	375,017	370,007	445,888	521,769
2030	353,979	371,616	382,774	372,947	454,357	535,766
2031	359,240	378,322	390,643	376,272	463,503	550,734
2032	364,479	385,185	398,831	379,737	473,046	566,356
2033	369,735	392,205	407,027	383,410	483,075	582,740
2034	375,107	399,384	415,456	386,404	492,540	598,677

Table 25. Annual maximum demand 2010-34

Year	High Maximum Demand (MW)	Low Maximum Demand (MW)	Moderate Maximum Demand (MW)	2010 IRP Rev1 Maximum Demand (MW)	CSIR_Moderate (MW)
2010	39216	38587	38885	38838	38388
2011	40629	39319	39956	40230	39084
2012	42027	40002	40995	41355	39828
2013	43839	41040	42416	42832	40639
2014	45255	41669	43436	44776	41471
2015	47124	42666	44865	47139	42283
2016	48479	43157	45786	48944	42603
2017	51090	44710	47870	50786	43923
2018	53276	45815	49516	52334	44698
2019	55573	46952	51233	54040	45477
2020	57649	47848	52719	55920	46374
2021	59885	48828	54326	57562	47271
2022	61932	49596	55734	59293	48251
2023	63955	50299	57097	61121	49264
2024	65870	50872	58340	62928	50221
2025	68458	51903	60150	64866	51171
2026	70866	52737	61770	66717	52049
2027	73320	53550	63404	68591	52981
2028	75606	54191	64867	70207	53975
2029	78066	54917	66460	72176	55017
2030	80272	55408	67809	73988	56101
2031	82625	55955	69258	75867	57180
2032	84895	56399	70615	77464	58303
2033	87641	57112	72344	79570	59405
2034	90162	57616	73856	81626	60567

Table 26. Assumed Energy Efficiency Demand Side Management (EEDSM)

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Comp Air	Capacity (MW)	39	76	115	151	211	275	275	275	275	275	275
	Energy (GWh)	297	581	881	1158	1619	2110	2110	2110	2110	2110	2110
Heat Pumps	Capacity (MW)	3	35	110	282	463	522	581	640	640	640	640
	Energy (GWh)	14	142	445	1,137	1,866	2,104	2,341	2,579	2,579	2,579	2,579
Lighting HVAC	Capacity (MW)	106	137	169	199	233	271	271	271	271	271	271
	Energy (GWh)	673	874	1,074	1,266	1,482	1,724	1,724	1,724	1,724	1,724	1,724
New Initiatives	Capacity (MW)	-	-	-	17	38	68	68	68	68	68	68
	Energy (GWh)	-	-	-	123	275	492	492	492	492	492	492
Process Optimisation	Capacity (MW)	81	151	210	293	384	467	467	467	467	467	467
	Energy (GWh)	608	1,137	1,582	2,208	2,895	3,521	3,521	3,521	3,521	3,521	3,521
Shower Heads	Capacity (MW)	-	20	85	85	85	85	85	85	85	85	85
	Energy (GWh)	-	58	248	248	248	248	248	248	248	248	248
Solar Water Heating	Capacity (MW)	26	78	123	287	556	910	1,263	1,617	1,617	1,617	1,617
	Energy (GWh)	76	227	360	838	1,622	2,656	3,689	4,722	4,722	4,722	4,722
Total	**Capacity (MW)**	**254**	**496**	**811**	**1,313**	**1,969**	**2,597**	**3,009**	**3,422**	**3,422**	**3,422**	**3,422**
	Energy (GWh)	**1,669**	**3,020**	**4,590**	**6,978**	**10,007**	**12,855**	**14,126**	**15,397**	**15,397**	**15,397**	**15,397**

Table 27. Existing South African generation capacity assumed for IRP

	Capacity (MW)
Eskom	**40635**
Camden	1520
Grootvlei	372
Komati	202
Arnot	2280
Hendrina	1870
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	**3260**
TOTAL	**43895**

Table 28. Technology costs input (as at 2010, without learning rates and 40% nuclear adjustments)

	Pulverised Coal with FGD	Fluidised bed with FGD	Nuclear	OCGT	CCGT	Wind	Concentrated PV	PV (crystalline silicon)	Forestry residue biomass	Municipal solid waste biomass	Pumped storage	Integrated Gasification Combined Cycle (IGCC)	CSP, parabolic trough, 9 hrs storage
Capacity, rated net	6X750 MW	6X250 MW	6X1600 MW	114,7 MW	711,3 MW	100X2 MW	10 MW	10MW	25 MW	25 MW	4X375 MW	1288 MW	125 MW
Life of programme	30	30	60	30	30	20	25	25	30	30	50	30	30
Lead time	9	9	16	2	3	3-6	2	2	3,5-4	3,5-4	8	5	4
Typical load factor (%)	85%	85%	92%	10%	50%	29% (7,8m/s wind @ 80m)	26,8%	19,4%	85%	85%	20%	85%	43,7%
Variable O&M (R/MWh)	44,4	99,1	95,2	0	0	0	0	0	31,1	38,2	4	14,4	0
Fixed O&M (R/kW/a)	455	365	-	70	148	266	502	208	972	2579	123	830	635
Variable Fuel costs (R/GJ)	15	7,5	6,25	200	80	-	-	-	19,5	0	-	15	-
Fuel Energy Content, HHV, kJ/kg	19220	12500	3,900,000,000	39,3 MJ/SCM	39,3 MJ/SCM	-	-	-	11760	11390	-	19220	-
Heat Rate, kJ/kWh, avg	9769	10081	10760	11926	7468	-	-	-	14185	18580	-	9758	-
Overnight capital costs (R/kW)	17785	14965	26575	3955	5780	14445	37225	20805	33270	66900	7913	24670	50910
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%	2,5%, 2,5%, 5%, 15%, 75%	10%, 90%	10%, 90%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	3%, 16%, 17%, 21%, 20%, 14%, 7%, 2%*	5%, 18%, 35%, 32%*, 10%	10%, 25%, 45%, 20%
Equivalent Avail	91,7	90,4	92-95	88,8	88,8	94-97	95	95	90	90	94	85,7	95
Maintenance	4,8	5,7	N/A	6,9	6,9	6	5	5	4	4	5	4,7	-
Unplanned outages	3,7	4,1	<2%	4,6	4,6	-	-	-	6	6	1	10,1	-
Water usage, l/MWh	229,1	33,3	6000 (sea)	19,8	12,8	-	-	-	210	200	-	256,8	245
Sorbent usage, kg/MWh	15,2	28,4	-	-	-	-	-	-	-	-	-	-	-
CO_2 emissions (kg/MWh)	936,2	976,9	-	622	376	-	-	-	1287	1607	-	857,1	-
SOx emissions (kg/MWh)	0,45	0,19	-	0	0	-	-	-	0,78	0,56	-	0,21	-
NOx emissions (kg/MWh)	2,30	0,20	-	0,28	0,29	-	-	-	0,61	0,80	-	0,01	-
Hg (kg/MWh)	1,27E-06	0	-	0	0	-	-	-	-	-	-	-	-
Particulates (kg/MWh)	0,13	0,09	-	0	0	-	-	-	0,16	0,28	-	-	-
Fly ash (kg/MWh)	168,5	35,1	-	-	-	-	-	-	24,2	1226	-	9,7	-
Bottom ash (kg/MWh)	3,32	140,53	-	-	-	-	-	-	6,1	3000	-	79,8	-
Expected COD of 1st unit	2018	2016	2022	2013	2016	2013	2018	2012	2014	2014	2018	2018	2018
Annual build limits	-	-	1 unit every 18 months	-	2500 MW after 2017	1600 MW	100 MW	1000MW					500 MW

Table 29. Import option costs

	Import hydro (Mozambique A)	Import hydro (Mozambique B)	Import coal (Botswana)	Import hydro (Mozambique C)	Import coal (Mozambique)	Import hydro (Zambia A)	Import hydro (Zambia B)	Import hydro (Zambia C)	Import gas (Namibia)
	Hydro	Hydro	Coal	Hydro	Coal	Hydro	Hydro	Hydro	Gas
Capacity	1125 MW	850 MW	1200 MW	160 MW	1000 MW	750 MW	120 MW	360 MW	711 MW
Life of programme	60	60	30	60	30	60	60	60	30
Lead time	9	9	5	4	5	8	3	4	5
Load factors (%)	66,7%	38%	85%	42%	N/A	46%	64%	38%	N/A
Variable O&M (R/MWh)	0	12,1	18	12,1	7,7	12,1	12,1	12,1	0
Fixed O&M (R/kW/a)	344	69,8	379	69,8	160	69,8	69,8	69,8	168
Variable Fuel costs (R/GJ)	N/A	N/A	15	N/A	2,88	N/A	N/A	N/A	74,4
Fixed fuel costs (R/kW/a)	N/A	N/A	-	N/A	-	N/A	N/A	N/A	-
Overnight capital costs (R/kW)	15518	7256	16880	15152	14400	6400	9464	4264	5780
Phasing in capital spent (% per year)	5%, 5%, 5%, 5%, 10%, 25%, 20%, 20%, 5%	5%, 5%, 5%, 5%, 10%, 25%, 20%, 20%, 5%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	5%, 5%, 5%, 5%, 10%, 25%, 25%, 20%	15%, 55%, 30%	10%, 25%, 45%, 20%	40%, 50%, 10%
Equivalent Avail	92	90	91,7	90	91,7	90	90	90	88,8
Maintenance	4	5	4,8	5	4,8	5	5	5	6,9
Unplanned outages	4	5	3,7	5	3,7	5	5	5	4,6
Water usage, l/MWh	-	-	100	-	100	-	-	-	12,8
Sorbent usage, kg/MWh	-	-	0	-	0	-	-	-	-
CO_2 emissions (kg/MWh)	-	-	924,4	-	924,4	-	-	-	376
SOx emissions (kg/MWh)	-	-	8,93	-	8,93	-	-	-	0
NOx emissions (kg/MWh)	-	-	2,26	-	2,26	-	-	-	0
Hg (kg/MWh)	-	-	1,22E-06	-	1,22E-06	-	-	-	0
Particulates (kg/MWh)	-	-	0,12	-	0,12	-	-	-	0
Fly ash (kg/MWh)	-	-	166,4	-	166,4	-	-	-	0
Bottom ash (kg/MWh)	-	-	3,28	-	3,28	-	-	-	0
Expected COD of 1st unit									

Table 30. Impact of learning rates on overnight capital costs.

Technology	Storage (hrs)	System size (MW)	Overnight capital costs (R/kWp) 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PV Crystalline	-	0.25	26462	24218	21974	20290	18772	17397	16150	15015	13979	13032	12164	11772	11395	11033	10685	10350	10028	9717	9419	9131	8854
	-	1	21421	19604	17787	16444	15230	14130	13131	12220	11388	10626	9927	9611	9307	9015	8734	8464	8203	7952	7711	7478	7253
	-	10	20805	19040	17276	15973	14796	13730	12760	11877	11069	10330	9652	9345	9050	8766	8494	8231	7978	7735	7500	7274	7056
PV Thin Film	-	0.25	23927	21476	19025	17802	16674	15630	14664	13769	12938	12165	11447	11040	10651	10280	9926	9588	9264	8954	8657	8373	8100
	-	1	19369	17384	15400	14428	13528	12695	11923	11206	10539	9919	9342	9013	8699	8400	8114	7840	7578	7328	7087	6857	6636
	-	10	18812	16885	14957	14015	13143	12335	11586	10891	10245	9643	9082	8764	8459	8168	7890	7625	7370	7127	6894	6670	6455
CPV	-	10	37225	31704	30298	29617	29037	28727	28350	28007	27546	27268	26770	25991	25396	24664	23842	23392	23000	22493	22342	22198	22060
CSP Parabolic Trough	0	125	27450	25809	22690	20512	18815	16453	15339	14422	13805	13293	12843	12586	12414	12268	12067	11895	11748	11650	11517	11428	11333
	3	125	37425	35188	30936	27965	25652	22432	20913	19663	18822	18123	17510	17160	16926	16726	16452	16218	16017	15884	15703	15580	15451
	6	125	43385	40792	35862	32419	29737	26005	24243	22794	21819	21009	20298	19893	19621	19390	19072	18801	18567	18413	18203	18062	17912
	9	125	50910	47867	42083	38042	34895	30515	28448	26748	25604	24653	23819	23343	23024	22753	22380	22062	21788	21607	21361	21194	21018
CSP Central Receiver	3	125	26910	25302	22244	20108	18445	16130	15037	14138	13534	13031	12590	12339	12170	12027	11829	11661	11517	11421	11291	11203	11110
	6	125	32190	30266	26609	24053	22064	19294	17988	16913	16189	15588	15060	14760	14558	14387	14150	13950	13776	13662	13506	13401	13290
	9	125	36225	34060	29944	27069	24830	21713	20242	19033	18218	17542	16948	16610	16383	16190	15924	15698	15503	15374	15199	15081	14955
	12	125	39025	36692	32258	29161	26749	23391	21807	20504	19626	18898	18258	17894	17649	17441	17155	16912	16701	16563	16374	16246	16111
	14	125	40200	37797	33230	30039	27554	24096	22464	21121	20217	19467	18808	18432	18181	17966	17672	17421	17204	17061	16867	16736	16597
Wind	-	200	14445	13902	13512	13239	13088	12857	12731	12564	12435	12355	12289	12233	12188	12113	12031	11986	11915	11894	11860	11821	11797
Biomass (bagasse)	-	52.5	21318	20969	20812	20605	20179	19970	19728	19523	19306	19165	19047	18977	18938	18879	18843	18808	18787	18758	18730	18690	18633
Biomass (MSW)	-	25	66900	65804	65313	64663	63326	62671	61911	61266	60587	60142	59772	59553	59433	59245	59133	59024	58958	58867	58777	58653	58474
Biomass (Forest Waste)	-	25	33270	32725	32481	32158	31493	31167	30789	30468	30131	29909	29725	29616	29556	29463	29407	29353	29320	29275	29231	29169	29080
IGCC	-	125	22325	21931	21783	21354	21129	20897	20756	20635	20495	20348	20177	20072	19929	19835	19712	19461	19433	19339	19292	19254	19226
Nuclear	-	1600	26575	26553	26532	26520	26481	26444	26422	26368	26337	26304	26285	26254	26247	26198	26141	26057	25994	25961	25889	25839	25801

APPENDIX E – MEDIUM TERM RISK MITIGATION PROJECT FOR ELECTRICITY IN SOUTH AFRICA (2010 TO 2016)

Keeping the Lights on

This is a National Project that deals with the anticipated electricity supply shortfall in the immediate medium term from 2011 to 2016, the period before entering into the IRP2010 planning horizon.

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1. EXECUTIVE SUMMARY

The South African electricity supply/demand balance will remain tight until such time as both Medupi and Kusile are put into operation. It will take substantial effort from all stakeholders to overcome South Africa's current electricity shortages. Load shedding, however, can be prevented, as long as all stakeholders partner to overcome all the obstacles to implementing the requisite identified initiatives on the supply and demand side and create a "safety net".

The Integrated Resource Plan 2010 is a long-term plan and does not provide sufficient detail to assess and mitigate the short-term supply shortages. Consequently, to better understand the risk, and assess options for mitigating the risk, the ***Medium Term Risk Mitigation Project*** sets out to quantify and qualify the current situation and propose an action plan, which needs be implemented urgently. As a result of this the generation capacities identified in the MTRMP will not reconcile with the capacities planned in the IRP due to the different purposes for each of the plans. The IRP addresses the long-term outlook for the generation mix in South Africa, while the MTRMP focus is on identifying and engaging all supply and demand options to address the short-term risk of the lack of capacity to meet demand over the 2011-2016 period.

This project will be implemented as a partnership between Government, Business, Labour, Civil Society and Eskom.

The current situation facing South Africa is:

- The risk of load shedding is significant unless extra-ordinary steps are taken to accelerate the realisation of a range of supply and demand side measures as set out by this project;
- The base case outlook up to 2016, based on the IRP 2010 moderate demand scenario, suggests a high likelihood that there will be an energy supply shortfall over the period until 2015. The supply/demand balance will be tightest during 2011-2012 as additional supply options are relatively limited until new build capacity starts to come on stream. The base case forecasts a supply shortfall of 9 TWh of energy in 2012, which is comparable to the energy produced by ~1000 MW of base-load capacity in a year;

- There is immense pressure on the ability of Eskom to maintain the Energy Availability Factor (EAF) of its existing generation assets due to the lack of time available to undertake adequate maintenance and to improve the quality of coal supplied to certain stations (coal quality is a major factor in EAF). The minimum desired target is to achieve an 85% EAF and this is under significant risk;

- Any delays in bringing the Medupi or Kusile generating units into operation will prolong and further exacerbate the shortfall in supply over the required economic demand; and

- Whilst opportunities exist to reduce the shortfall in supply, they are constrained by a range of obstacles to implementation.

In order to ensure that this shortfall is addressed the following demand and supply side initiatives are required to be implemented[3]:

- Eskom's demand side management programme must be executed and, working with stakeholders, additional funding must be leveraged to achieve more savings than currently planned for. It is estimated that an additional 25% of planned savings can be achieved in the next 3 years.

- Government's target for the rollout of 1 million solar water geysers must be achieved.

- Innovative incentive-based mechanisms must be created for customers to contribute to demand response programmes. Such a programme exists for large customers and programmes need to be created for smaller customers.

- The non-Eskom co-generation, own generation and renewable generation targets for the next 3 to 5 years must be achieved. Of the target of over 2 300 MW, 277 MW has already been signed up. All stakeholders need to work together to finalise the grid access framework and to sign up IPPs within the tariff allowances and in line with IRP 2010. Further opportunities must be investigated.

- Eskom must focus on increasing its generation availability by between 1 and 2%.

- Eskom must bring back its return to service generation fleet as planned.

[3] Details are available in the full report.

- Stakeholders must work together to support the operation of existing municipal generation where feasible.

Even with these initiatives, (assuming they are successful) there are further risks that may materialise and some of the programmes may not deliver the requisite planned contributions. Under certain scenarios a shortfall will still exist in 2011 and 2012 of between 3 and 6 TWh. In order to provide a "safety net" to deal with these risks, the following will be considered for urgent implementation:

- Establishing a mandatory Energy Conservation Scheme focusing on the largest users of electricity in the country to be ready for speedy implementation, should it be determined that rationing is required to prevent load shedding.

- This can be supported by additional demand response initiatives focused on the smaller customers including residential customers, using technology and other mechanisms.

- A mechanism to support the higher usage of the open cycle gas turbines in the Western Cape when needed.

These measures can be achieved if the collective stakeholders work together.

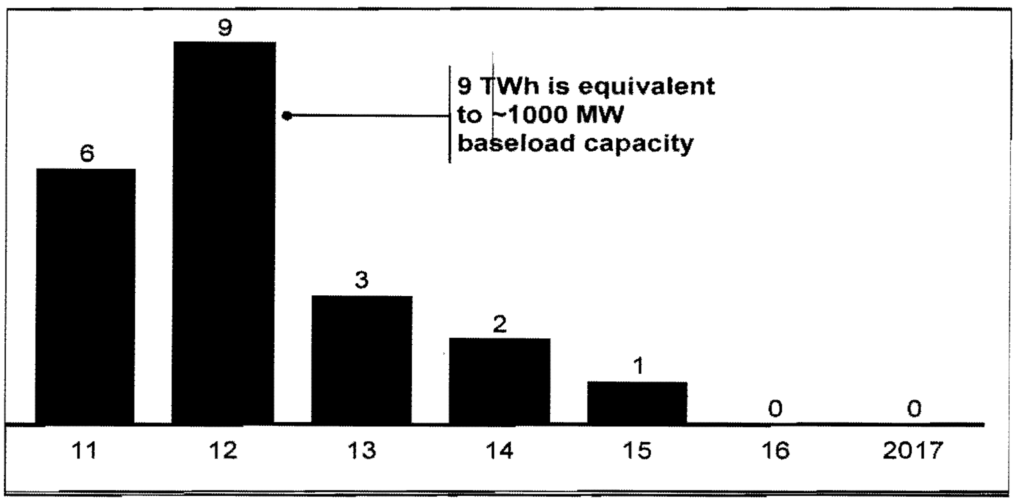
2. THE ANTICIPATED SUPPLY SHORTAGES BETWEEN 2010 AND 2016

The base-case outlook up to 2016 (based on the IRP2010 moderate demand scenario) suggests a high likelihood that there will be an energy supply shortfall over the period until 2015. The supply/demand balance will be tightest for 2011-2012 as additional supply options are relatively limited until new build capacity (Medupi and Kusile) starts to come on stream. The base case forecasts a supply shortfall of 9 TWh of energy in 2012, which is comparable to the energy produced by ~1000 MW of base load capacity in a year.

Figure 1 - Gap before mitigation

SA electricity supply-demand balance will remain tight until 2015 with 2011/2012 the crucial period

Current forecast of the annual energy gap for 2010 to 2017, TWh shortfall



Assumptions:

- Eskom estimate of the IRP 2010 moderate load forecast (~ 260 TWh in 2010)
- New Build (e.g. Medupi, Kusile Ingula) & RTS at current dates
- REFIT as IRP1 8
- DoE Peaking IPP included
- DSM as per base plan (3.9 GW by FY 2018).
- Planned maintenance allocation increased to 10%

These supply constraints are further complicated and increased by the urgent need to undertake critical maintenance on the generation assets over this period. Space needs to be created on the system to support a comprehensive maintenance programme to sustain the operational integrity of the generation assets. Some of this maintenance has already been significantly postponed and further delays create health and safety risks and increase the risk of serious breakdowns and outages.

The risk of additional downside to the base case outlook

This base case outlook includes a number of existing commitments and the IRP2010 moderate demand forecast. Up to 3 TWh of these base case supply options is at risk over the critical period, 2011-2012, because of the uncertainty relating to some existing commitments and base case assumptions[4]:

- Committed supply side risks
  - New build, Return-To-Service (RTS) and REFIT. Supply constraints are severe in the next two to three years and decrease as new build and RTS options are commissioned. However delays in the delivery of any new build (especially Medupi and Kusile) and RTS projects significantly impact on security of supply in these latter years. Any delay on a unit of Medupi or Kusile increases the annual energy gap.
  - REFIT supply of 1 GW by 2015 (as per IRP 2010) has also been included in base case projections. There is significant risk that these options do not deliver the committed capacity on time, as the regulatory and legislative framework has not been put in place to facilitate the procurement process. Failure to unlock these constraints urgently could put this energy at risk, given the lengthy implementation timelines required.

[4] The base case outlook assumes that existing business commitments fully deliver according to current schedules. Any slippage or under-delivery on these commitments will worsen the situation and increase the size of the energy gap over critical years.

- Demand Side risks
    - Demand Side Management - Demand side reduction of ~4 TWh has been built into base case forecasts by 2013, through Demand Side Management (DSM) commitments made in MYPD 2. Significant work still needs to be done and constraints unlocked to deliver these commitments. Under-delivery on these commitments will add further pressure during critical years.
    - National Demand - The supply-demand gap increases significantly if national demand over this period exceeds IRP2010 moderate forecasts. Current demand is lower than the IRP moderate scenario however the assumption is that this will rebound by 2012 to reflect the moderate forecast. A quicker-than-predicted economic recovery would increase demand forecasts above the moderate scenario, further increasing supply-demand constraints and adding to the energy gap.

NB: The scenarios clearly illustrate the urgent need to take immediate action and the necessity to put in place risk mitigation until at least 2016.

3. ASSESSMENT OF AVAILABLE RISK MITIGATION SOLUTIONS

There is no silver bullet to address the supply gap, therefore a range of options have been identified to reduce this supply-demand shortfall. These solutions assist to close the majority of this gap; however large constraints and challenges exist and many of the options identified do not fall purely within the control of a single industry stakeholder. An active partnership is required among key stakeholders (Eskom, Business, Government, the Regulator and the public) to unlock these and deliver maximum potential from available levers.

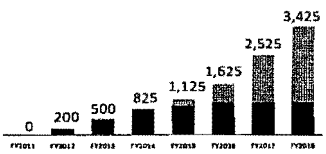
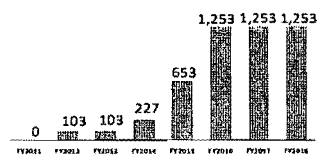
Each option has been evaluated to identify the maximum potential that could be delivered within a specified time frame, termed the *constrained* potential. A number of real constraints apply to each option (e.g. funding, legislation, logistics), which decreases the potential. The *highly constrained* potential is the stretched opportunity believed to be possible, making realistic assumptions on future funding. In some cases, the constrained potential has already been included in the base case analysis. This is indicated as such.

The following options have been identified as opportunities to close the gap:

3.1 Supply side options and constraints

TABLE 1 – SUPPLY SIDE OPTIONS AND CONSTRAINTS

■ *Constrained potential (MW)* ■ *Highly Constrained potential (MW)*

Option	Quantification	Constraints (not exhaustive)
Renewable energy (REFIT) programme *Constrained potential has been included in the base case analysis*		Regulatory and legislative framework required to enable procurement process Lead time required for implementation
Cogen / Own Gen (Conservative view of 1000 – 1500MW)		Access to municipal distribution systems Rules for fair and equitable transport of electricity over grid Onerous licencing and grids code requirements for small distributed gens

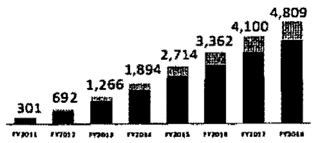
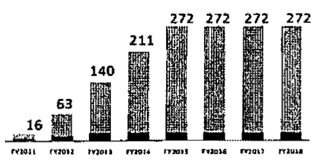
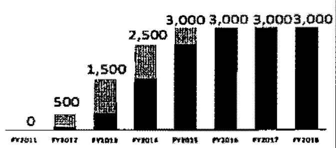
Supply side options from within the SADC region have not been considered here as the time frame for implementation as included in the IRP 2010 is beyond the window being discussed here.

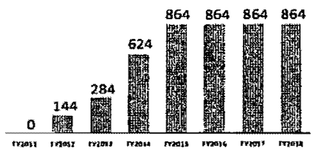
Additional municipal generation capacity, and increased Eskom capacity, specifically from upgrades at Koeberg (~ 30 MW per unit) as well as the increased generation availability from the existing fleet, by improving on the forced outage rate (1% improvement by 2012 equating to ~ 2.5 TWh) have been included in the calculations to determine the magnitude of the gap.

3.2 Demand side options and constraints

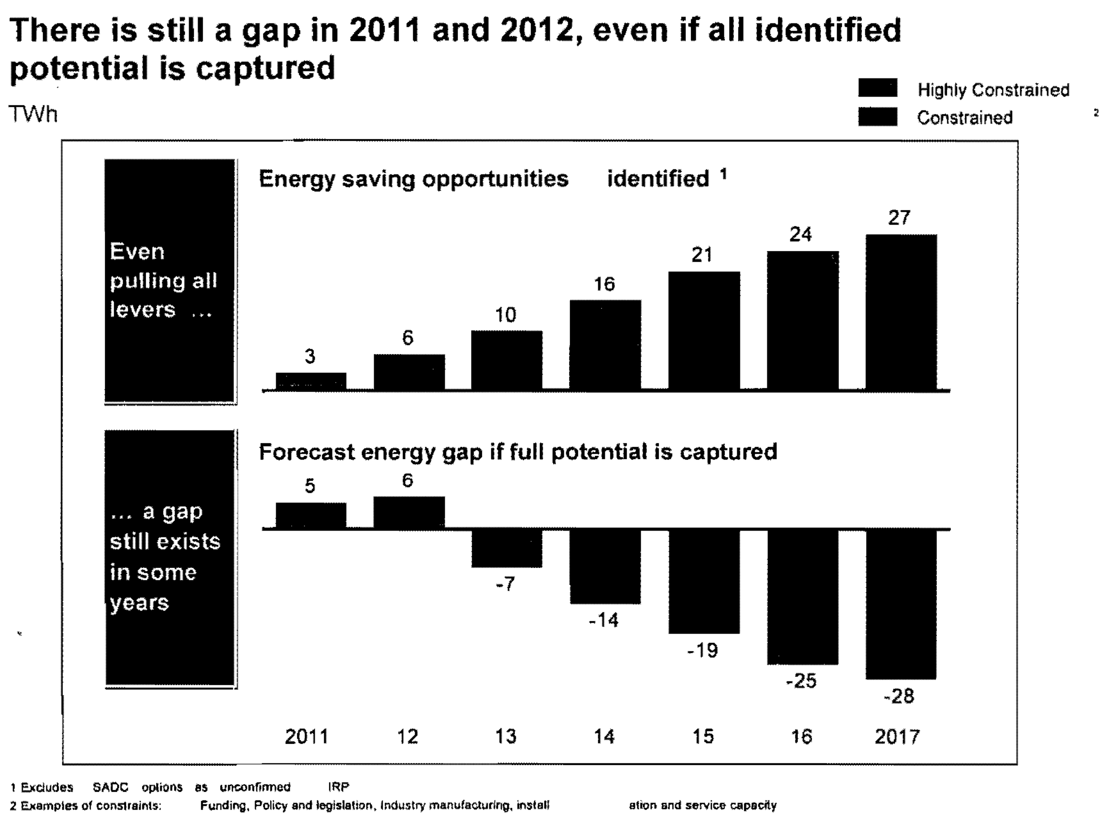
TABLE 2 – DEMAND SIDE OPTIONS AND CONSTRAINTS

■ *Constrained potential (MW)* ■ *Highly Constrained potential (MW)*

Option	Quantification	Constraints
Demand side management (Additional 25% on existing commitments) *Constrained potential has been included in the base case analysis*		Logistics to implement - benefit achieved as small saving across large number of consumption points Procurement and installation capability for energy efficient devices Funding
Government Solar Water Heating (1 million installations)		Funding model for > 580 000 installations Procurement and installation capability – shortage of suppliers and qualified installers (plumbers)
Incentivised Demand Response - Small commercial and industrial		Funding required to deliver DR above 500 MW (first 500 MW budgeted using DMP under spend) Capability of third party to sign up customers (voluntary DR programme) Approval of integrated DR strategy

Residential demand response (1.8 million customers)		Municipal roll-out (technology & buy-in) Funding Decision over best technology to implement (short/long term) Impact on customers for higher energy factors if load limiting used too often Clarity on legislation Integrated demand response strategy

The analysis indicates that a residual energy gap remains in the next two to three years, even if maximum potential across all available opportunities are realised. This gap will likely be in the 3 – 6 TWh range, depending on the ability to unlock the constraints of options identified and to deliver against these targets.



3.3 Dealing with the remaining gap – Implementing a "safety net"

Three additional options exist and can be implemented as a "safety net" to protect South Africa from national load shedding by closing any residual gap or additional gap if the initial options do not deliver or if demand increases exceed current forecasts.

Energy Conservation Scheme (ECS)

ECS is legislated energy reduction for (initially) the 500 largest electricity users by setting a reduction target and imposing penalties for non-compliance. Analysis shows that a mere 5% saving on the historical base-line for these customers would provide an estimated (6 TWh) energy saving.

- While ECS can be viewed as an economic threat, it has inherent country benefits. It encourages movement towards a more energy efficient economy, and reduces absolute demand and is economically preferred to national load shedding.
- It is believed that this 5% reduction could be achieved without a loss in production and in most cases the investment would be net positive for the users. However there remains concern around the short-term impact of legislated demand reduction on economic growth.

The DOE has the policy ownership for the development and implementation of ECS. The rules of the scheme will be finalised, and a decision on the enabling legislation (Energy Act or Electricity Regulation Act) will be made.

Compulsory Demand Response (DR)

- Implementation of mandatory demand response measures amongst residential customers allows for demand management during periods of system constraint. Mandatory demand response measures enable the supplier to warn customers of demand restrictions during peak times, and remotely limit consumption when required, by either capping energy supply to customers or cutting off customers who consume above a set level. This differs from incentivised DR options for commercial and small industrial customers, which requires voluntary sign-up by customers and voluntary reduction in energy consumption.

- DR in this form is essentially a milder form of load shedding, significantly limiting energy available to customers during periods of system constraint, for set duration. Although customers have consumption restrictions, DR is preferred over full load shedding as it permits customers to operate basic appliances (e.g., television and lights, or refrigerator).

- There are a number of different options for implementing DR and the most appropriate technology still needs to be confirmed.

Increasing OCGT load factor

- Eskom can increase operation of OCGT capacity during these critical years. Increasing operation of the OCGTs could create space for critical maintenance on other plant, in order to increase availability of these options during critical periods. Increasing OCGT operation by 5% would provide ~1 TWh of additional energy per annum.

- Increasing operation of OCGTs creates significant additional cost for Eskom of ~R2bn per TWh of additional energy. A funding model needs to be agreed with NERSA to support additional operation of this capacity during periods of system constraint. (This could tie in with the ECS - if large users do not reduce their demand they cover the cost of more expensive generation).

4. THE MEDIUM RISK MITIGATION PROJECT IMPLEMENTATION

The Department of Energy and Government have committed to working with NEDLAC to implement the Risk Mitigation Project. A plan of action has been agreed between NEDLAC and Government.

The MTRMP has already completed the following project phases:

Phase 1 is complete and consisted of:

- A realistic assessment of the medium term supply and demand outlook;

- Risk assessing the expected energy shortfalls, so that appropriate mitigation measures can be developed;

- Assessing the state of supply and demand mitigation measures[5] inclusive of any binding constraints and "remedies" to resolve such constraints; and
- Developing a Project Plan for the implementation.

Phase 2 (Implementation) consists of the following agreed work plan:

- Development and promulgation of legal framework to promote non-Eskom generation:
  - Finalise regulatory framework for the procurement of non-Eskom generated power;
  - Address licensing regulations;
  - Develop and implement rules to promote non-Eskom generation;
  - Development of appropriate and equitable wheeling charges for all generators;
  - Streamline the process for approving access to the grid for non-Eskom generators;
  - Develop rules of costs and access to municipal distribution systems;
- Development of fast track process for projects that will alleviate pressure on grid until 2016
  - Roll out of solar water heater plans;
  - Streamline the approval processes for all non-Eskom generation options during the constrained period;
  - Implement procurement processes to purchase power identified both in the IRP and the MTRMP;
  - Finalisation of procurement process for generation technology not included in MYPD2.

- Finalise National Energy Efficiency Strategy review and develop implementation plan
    - Develop and implement action plan to introduce energy efficiency instruments;
    - Establish reporting mechanism to report on progress on energy efficiency interventions.
- Develop the national contingency plan (Safety Net)
    - Develop policy statement on the legal platform for the Conservation Scheme, its scope of application and the mechanisms for triggering.
    - Identification of most appropriate systems and technology for aggregated demand response management
- Development of a comprehensive approach to funding EE interventions including:
    - Fast track the finalisation of tax rebate scheme 12L;
    - Finalise the approach to the Standard Offer.
- Develop a sustainable funding model to support the following interventions:
    - Aggregation of demand response at municipal and Eskom level
    - Emergency use of OCGT to prevent load shedding
- Execution and monitoring of actions
    - Establish a technical team to undertake technical work as directed by this action plan;
    - Establish a reporting and feedback mechanism for monthly reporting of progress to stakeholders through Nedlac.
- Develop comprehensive energy efficiency awareness campaign
    - Nedlac energy task team to develop a proposal for consideration by NSACE.