Transmission Company of Nigeria

Tariff Filing 2014-2015

Submission to the Nigerian Electricity Regulatory Commission (NERC)

5/26/2014

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Submission to NERC, May, 2014

1. Background

1. Electricity tariffs for generation, transmission and distribution companies were determined by the Nigerian Electricity Regulatory Commission (NERC) in 2012 under a second Multi-Year Tariff Order (MYTO 2) covering a period of five years from June 1, 2012 to May 31, 2017. Separate Tariff Orders were issued for Generation, Transmission and Distribution. TCN's regulated transmission use of system (TUOS) charges or tariffs since June 2012 have been applied in accordance with the transmission MYTO 2.

2. There are separate transmission tariffs for TSP (use of system charge), MO and SO. The tariff calculations prepared by NERC for MYTO 2 developed costs for TCN on a consolidated basis, and then apportioned the total costs to the Business Units (BU). For this tariff filing, TCN has developed separate calculations for each Business Unit, i.e. the approach is bottom up by BU.

3. The Transmission Use of System Charge (TUOS) is levied on distributor/retailers and charged per unit of energy delivered to them at the bulk supply points. The TUOS charge is determined using the building blocks methodology, bringing together existing and forecast capital costs, an allowance for a return on capital and depreciation and efficient operating costs. The TUOS charge is mostly comprised of the system's fixed charges, such as the return on capital, depreciation and operation and maintenance. The charges are uniform throughout Nigeria (sometimes referred to as a postage stamp tariff) and billed monthly to distributors/retailers.

4. The tariff order states that transmission charges will be reviewed bi-annually and a change made to the TUOS charge if Nigerian inflation, exchange rate and generation capacity has varied materially from that used in the calculation of the tariff. It was intended that a major review would be conducted in 2016, but there have been some major changes since MYTO 2 was issued and TCN now requests that a major review be done now on an expedited basis.

2. Need for Tariff Review

5. A number of significant changes have taken place or are expected in 2014/15 since MYTO 2 tariffs were determined two years ago. Existing MYTO 2 tariffs and billing collections are inadequate for TCN to finance its operations. There is an urgent need for a major review and revision of transmission tariffs to enable TCN to adequately maintain and operate the network and to grow the infrastructure in step

with rapid expansion of generation and load. Lack of maintenance of the network over the past two decades has adversely impacted on system reliability and delivery.

6. The principal factors that have been taken into account in this tariff review are summarized below:

i) The annual network maintenance and operating requirements for proper operations must be increased to bring the system up to standard and maintain it at a higher level. The needed O&M costs are significantly higher than MYTO 2 allowance. Only 58% of needed operating expenses in 2015 is covered in MYTO.

ii) Higher asset base resulting in higher depreciation on assets in service and returns on capital employed:

   a) Anticipated transfer of NIPP transmission assets (US$ 2.0 billion) in October 2014[1].
   b) Transfer of transmission assets (US$ 464 million) recorded in PHCN books.
   c) Transfer from PMU to TCN of the World Bank funded transmission investments (US$ 151 million).
   d) Investment in plant using internally generated funds.

iii) Total investments over the next five years are projected to be US$7.8 billion (in 2013 prices). Much of projected expansion is based on the assumption that TCN will be able to cover the carrying charges associated with the new incremental debt load. FGN Appropriations are not sufficient to cover future financing needs. Borrowing from the FGN is becoming increasingly difficult without having the capacity to cover the on-lent commitments.

   The increase in capital expenditure brings with it an increase in carrying cost (return on capital) and an increase in depreciation expense. Inclusion of these expenses will allow TCN to become self-sufficient and less dependent on grants and FGN financing.

iv) Although the revenue requirements of TCN are mostly of a fixed nature, the transmission tariff determined by NERC is based on the volume of bulk supply to Distribution Companies (DisCos). In other words, the existing tariff is volume based. MYTO 2 tariffs were designed based on volume throughput which are:

   a) 28% higher than actual for 2013
   b) 49% higher than projected for 2014
   c) 44% higher than projected for 2015

[1] The valuation and date of transfer have yet to be determined. Estimates have been used in this submission.

The energy (MWh) unit rates as per MYTO 2 estimates are consequently much lower than they would be if they were based on actual and latest projected energy supply. MYTO based billed revenues are therefore inadequate to recover TCN's fixed costs (opex, depreciation and returns on asset base).

3. Tariff Application

7. TCN hereby submits an Application for revised transmission tariffs to be applied in 2014/15. It is proposed that transmission tariffs are fixed in terms of monthly charges rather than variable energy based tariffs as currently applied under MYTO. The initial working document was prepared assuming a tariff change effective August 1, 2014. However, given the test year covers the period from January 1st, revised tariffs can be implemented effective May 31st to be in concert with the other participants in the power sector. The earlier implementation date is to the benefit of TCN in that that unrecovered revenue shortfall during the early months of 2014 will be minimized.

8. The annual revenue requirements of TCN as per its Business Plan are estimated at NGN 107 billion in 2014 and NGN 157 billion in 2015. The projected revenue requirements for 2015 are 2.25 times of MYTO 2 estimates, as indicated in Table 3-1 below.

Table 3-1: TCN Revenue Requirements 2014-15 (in Nominal NGN millions)

	Business Plan		MYTO 2		% Funded	
	2014	2015	2014	2015	2014	2015
Operating expenses	47,596	57,765	32,004	33,358	67%	58%
Return on Asset Base	42,944	73,391	11,698	19,031	27%	26%
Depreciation	16,540	26,224	14,376	17,457	87%	67%
Total annual revenue requirements	107,080	157,380	58,078	69,847	54%	44%
Equivalent to Monthly Fixed Charge	8,923	13,115	4,840	5,821		
Compared with MYTO 2 (times)	1.84	2.25				

9. In terms of bulk energy supply, the average transmission tariff for TSP and each of SO and MO needs to increase from the present rate of 1,367 N/MWh to 4,824 N/MWh for TCN to achieve full cost recovery in 2015 which is 3.53 times of TCN's existing tariff. The proportion related to 2014 is 2.85 times. It is proposed that a one-time increase of 3.53 times of the present tariff is applied effective August 1, 2014 so as to avoid a second increase in January 2015. The surplus billing collections estimated at NGN 8 billion in 2014 relating to advancing the January 1, 2015 increase will be applied to the revenue deficiency for the first seven months of 2014 and will assist in clearing existing overdue liabilities. The key statistics are summarized in Table 3-2 below. As noted above in section 8, an earlier implementation date of May 31st is beneficial to TCN and will reduce the hardship period for 2014 to five months.

Table 3-2: Key Statistics 2013-15

	2013	2014	2015	2014	2015
				% change	
Bulk supply to DisCos (GWh)	25,373	27,446	32,622	8.2%	18.9%
TCN component of revenue requirements	70,302	107,080	157,380	52.3%	47.0%
TSP wheeling & SO/MO service charges (NGN/MWh):					
Cost reflective tariff (in calendar years)	2,771	3,901	4,824	40.8%	23.7%
MYTO 2 tariff (in calendar years)	1,407	1,355	1,419	-3.7%	4.8%
MYTO 2 tariff (in May each year)	1,462	1,367	1,346	-6.5%	-1.6%
Cost reflective vs. MYTO 2 (times)	1.97	2.88	3.40		
Cost reflective vs. MYTO 2 in May 2014 (times)		2.85	3.53		

10. In comparing the latest estimates with MYTO 2 figures, it is important to note that although the revenue requirements in 2015 are 2.25 times higher, the average transmission tariff in terms of bulk energy supply is 3.4 higher. This wide difference illustrates the dilemma that TCN has faced since 2012 in under-recovery of its costs since MYTO tariffs were established.

11. TCN's component/share of the total existing sector revenue requirements will increase from 7% to 15%, assuming no changes to MYTO estimated revenue requirements of other market participants. The total tariff to distribution customers, including costs of generation, transmission, distribution and other services will increase by approximately 10%.

12. The principal assumptions and detailed calculations of the projected revenue requirements and the resulting tariffs in 2014/15 are presented in this paper.

4. Tariff Structure

13. TCN proposes to change the manner in which the current revenue requirement is collected from the DisCos. Currently the revenue requirement for each of the Business Unit Tariffs (each of TSP, SO and MO) is divided by the projected volumes to determine a unit rate. The unit rate is then applied to the actual volumes wheeled each month. This gives rise to substantial variability in amounts collected due to the differential in volume throughput. If throughput volumes are greater than projected, TCN will over-collect and conversely, if the volumes are lower than projected, there will be a shortfall in the revenues flowing to TCN.

14. Transmission tariffs should be levied on each DisCo as a fixed charge, adjusted in proportion to each DisCos load share relative to the total throughput for each month, rather than a volumetric charge as per MYTO 2. A fixed charge structure recognizes that TCN's costs are for the most part 100% fixed. TCN will no longer be exposed to risk of under-recovery due to actual quantities falling below projected levels currently used in setting the tariff.

15. Following this proposed approach, the annual revenue requirement will be divided by 12 to determine a monthly revenue requirement. The monthly revenue

requirement will then be apportioned to each DisCo each month based on the relative energy volumes taken by each DisCo.

16. Should the fixed charge structure not be endorsed by NERC, TCN requests an Annual Energy Adjustment Clause such that any over/under recoveries in one year can be carried over to the following year as a Rate Rider. This second choice however is not preferred as it will give rise to intergenerational inequity.

17. It is universally accepted that allowable transmission revenue requirements should be recovered regardless of actual energy throughput amounts, which depend on supply-demand dynamics wholly outside of the control of the transmission company, and there are few if any other countries that put the transmission company at risk if supply underperforms. The current volumetric approach used for transmission cost recovery in Nigeria is inequitable and unsustainable, especially in the current environment in which the quantum of energy wheeled is unpredictable and has persistently underperformed relative to expectations. The use of fixed charge tariffs already has a precedent in the Nigerian electric sector, as the generators are allowed capacity charges for their fixed costs. TCN is entitled to similar treatment.

5. Recent Performance

Operational Performance

18. TCN's key operational performance indicators over the last three years are indicated in Table 5-1 and Chart 1 below.

Table 5-1: Operational Indicators 2011-13

	2011	2012	2013
Peak generation (MW)	4,089	4,518	4,458
Average generation (MW)	3,082	3,298	3,297
Growth in peak generation	7.5%	10.5%	-1.3%
Energy wheeled (sent out by stations) (GWh)	26,999	28,890	28,879
Growth in energy sent out	10.8%	7.0%	0.0%
Transmission losses (%)	10.4%	12.1%	12.1%
Bulk supply to DisCos (GWh)	24,205	25,385	25,373
Number of staff at December 31	3,334	3,958	4,210

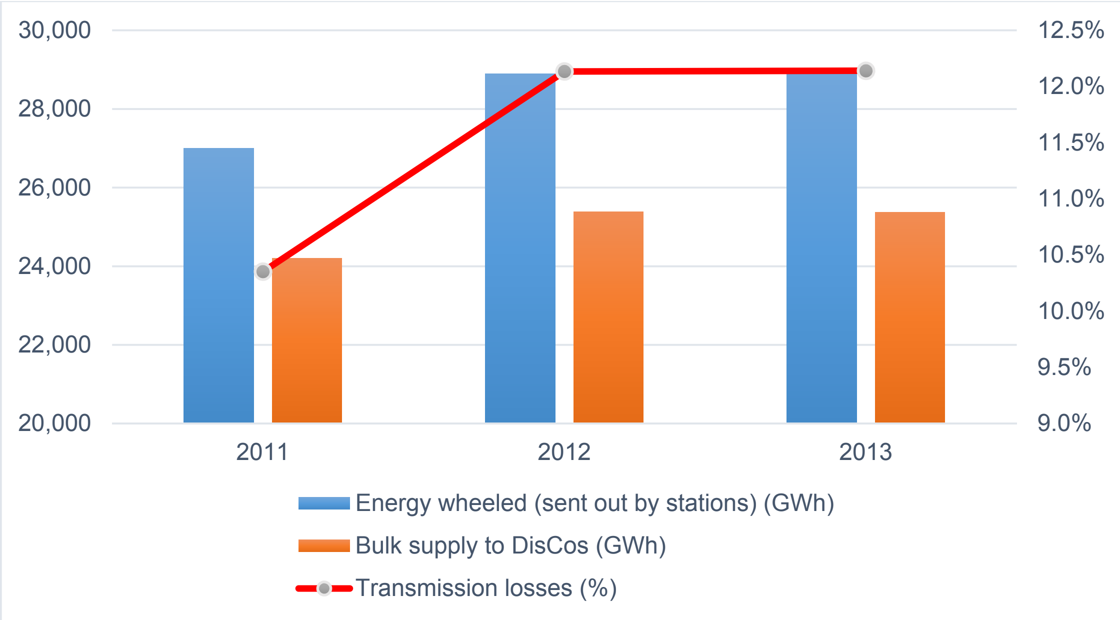

Chart 1: Operational Indicators 2011-13

19. Peak generation of around 4,500 MW in the last two years was more or less equal to the capacity of the transmission network to transmit the available generation to the DisCos. Energy wheeled (sent out by stations) registered growth rates of 10.8% in 2011, 7.0% in 2012 and remained almost unchanged in 2013. Total wheeled energy in 2013 reached 28,879GWh. Performance in terms of transmission losses has deteriorated since 2011, increasing from 10.4% in 2011 to 12.1% in 2012/13. The high losses include non-technical losses attributable to illegal connections by some large industrial consumers. Inadequate maintenance of the transmission network over the years has resulted in high technical losses. These matters are being addressed.

20. The number of staff employed by TCN increased from 3,334 in 2011 to 4,210 by end 2013.

Financial Performance

21. TCN is technically insolvent as the existing MYTO transmission tariffs and billing collections are inadequate for the company to finance its operations. The company is consistently unable to meet its obligations to suppliers/contractors in compliance with terms of contracts. TCN is fortunate that the company has FGN backing. The present financial situation of the company is not sustainable.

22. Non-collection of tariff charges is a significant recurring problem for TCN. The Interim Market Rules (pre-TEM) provides for collection of 70% for TSP and 60% for SO and MO. However, the overall average collection rate in 2013 was around 60%. Retail billing collections by DisCos have dropped to 45% in the last two months and this will impact on all the Market Participants and Service Providers, including TCN. Chart 2 below shows the monthly billing collection performance in 2013.

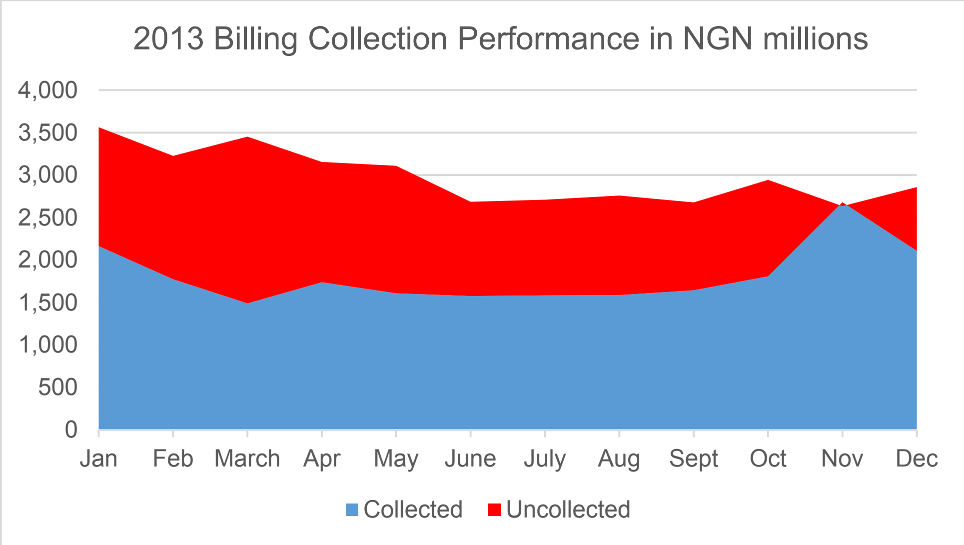

Chart 2: 2013 Monthly Collected & Uncollected Revenues in NGN millions

23. The company's unpaid billing due from the market fund as at December 31, 2013 amounted to NGN 52 billion (US$331 million), equivalent to 147% – or 18 months – of TCN's annual revenues in 2013.

24. Table 3-1 below provides the key financial performance indicators over the past three years.

Table 5-2: Financial Indicators 2011-13

	2011	2012	2013
Av tariff (NGN/MWh)	1,316	1,425	1,432
Av tariff (US$/MWh)	8.64	9.12	9.20
Av operating profit/(loss) (NGN/MWh)	302	(233)	(338)
Av operating profit/(loss) (US$/MWh)	1.98	(1.49)	(2.17)
Net profit/(loss) (NGN millions)	7,423	(5,794)	(8,543)
Net profit/(loss) (US$ millions)	49	(37)	(55)
EBITDA (%)	52.2%	12.3%	6.1%
Operating margin	22.4%	-15.9%	-22.6%
Return on equity	2.3%	-1.9%	-2.6%
Current ratio (times)		4.1	4.5
Debt/equity ratio		8.0%	10.5%

25. The average transmission tariff increased from 1,316 NGN/MWh in 2011 to 1,425 NGN/MWh in 2012 and declined slightly in 2013 to 1,432 NGN/MWh. The average tariff increased by 8.8% over the last two years compared with domestic inflation of 21.7% over the same period.

26. TCN made pre-tax losses of FGN14.3 billion (US$92 million) in 2012/13 with negative operative margin of 19.3%, based on unaudited financial statements. Net cash outflows over the past two years to December 2013 amounted to NGN2.1 billion (US$13 million). The company had a low debt/equity ratio of 10.5% as at December 31, 2013.

6. Investment Plan 2014-2018

27. TCN's investment plan for 2014-18 in US dollars and Naira are summarized in Table 6-1 and Table 6-2 below. Details of the investment plans of each Business Unit (BU) are provided in Annex 1.

28. Total investments over the next five years to 2018 are projected at US$ 7.8 billion in 2013 prices, equivalent to NGN 1,361 billion in nominal prices. The primary targets are to increase the current capacity of the grid from 7 GW to 10 GW by 2017, and to 20 GW by 2020. The assumed disbursement profile of the investment plan is front loaded for opening of letters of credit covering 70% of project costs.

Table 6-1: Investment Plan 2014-18 (in 2013 US$ millions)

In 2013 US$ millions	2014	2015	2016	2017	2018	2014-18
Plant & Machinery:						
TSP Substation Refurbishment	568	237	47	47	47	947
TSP New Lines and Substations	495	2,059	1,434	1,271	1,086	6,345
SO capital expenditure	26	34	6	6	6	78
MO capital expenditure	0	0	0	0	0	0
Total P&M	1,090	2,330	1,488	1,324	1,139	7,370
Other Assets:						
Land & Buildings	104	144	20	20	20	308
Helicopters	37	0	0	0	0	37
Furniture & Fittings	16	26	5	4	4	56
Motor Vehicles	40	15	12	13	13	93
Total Other Assets	197	185	37	37	37	494
Totals in 2013 US$ millions	1,286	2,515	1,525	1,361	1,176	7,864
Totals in Nominal US$ millions	1,306	2,598	1,606	1,465	1,294	8,269
Totals in 2013 NGN millions	199,661	390,318	236,693	211,272	182,576	1,220,521
Totals in Nominal NGN millions	205,212	418,504	265,203	247,828	224,395	1,361,142

Table 6-2: Investment Plan 2014-18 (in Nominal NGN millions)

In Nominal NGN millions	2014	2015	2016	2017	2018	2014-18
Plant & Machinery:						
TSP Substation Refurbishment	90,605	39,384	8,231	8,617	9,029	155,866
TSP New Lines and Substations	79,027	342,671	249,421	231,359	207,071	1,109,549
SO capital expenditure	4,181	5,603	1,043	1,092	1,144	13,064
MO capital expenditure	0	0	0	0	0	0
Total P&M	173,813	387,658	258,695	241,069	217,245	1,278,479
Other Assets:						
Land & Buildings	16,589	23,963	3,478	3,641	3,815	51,486
Helicopters	5,767	0	0	0	0	5,767
Furniture & Fittings	2,612	4,330	883	798	827	9,450
Motor Vehicles	6,343	2,554	2,147	2,321	2,508	15,872
Total Other Assets	31,312	30,846	6,508	6,759	7,150	82,575
Totals in Nominal NGN millions	205,125	418,504	265,203	247,828	224,395	1,361,055

29. The investment financing plan in US dollars is indicated in Table 6-3 below.

Table 6-3: Investment Financing Plan 2014-18 (in Nominal US$ millions)

In Nominal US$ millions	2014	2015	2016	2017	2018	2014-18	
Secured Loans:							
AfDB (EPSERP)	150	0	0	0	0	150	1.8%
World Bank (NEGIP)	47	121	0	0	0	168	2.0%
Eurobond	90	46	0	0	0	136	1.6%
AFD	0	119	32	19	0	170	2.1%
Total Secured Loans	287	285	32	19	0	623	7.5%
Government							
NDPHC - Sale of NIPP GenCos	800	800	0	0	0	1,600	19.3%
FGN Budget Appropriations	162	125	125	125	125	662	8.0%
Total Govt Contributions (Equity)	962	925	125	125	125	2,262	27.4%
Total identified funding	1,249	1,210	157	144	125	2,885	34.9%
IGR funded investments:							
Office equipment, F&F and vehicles	57	43	18	18	19	156	1.9%
Financing Gap	0	1,345	1,431	1,302	1,149	5,228	63.2%
Total investments	1,306	2,598	1,606	1,465	1,294	8,269	100.0%

30. Financing is secured or expected for around 35% of the investment requirements and the remaining 65% remains to be secured through borrowing and internally generated revenues (IGR). Investment funding from IGR will largely depend on the adequacy of transmission tariffs in the future. It is assumed that US$ 1.6 billion of GenCo sale proceeds will be provided to TCN and that these funds will be applied towards investments. However, a proportion of such funding may have to be utilized towards shortfalls in revenue requirements in 2014/15 in the event that tariffs are not revised upwards (refer to Section11 further below for further details). It is further assumed that FGN will provide annual capital grants of US$ 125 million to 2018.

31. The above table indicates that if NDPHC were to invest all of the proceeds from the privatization to fund transmission projects, TCN's funding gap in 2014 would be eliminated, and the funding gap in 2015 would be reduced significantly. It should be noted that most of the TCN capital spending program in 2014 consists of substation refurbishment and completion of ongoing projects, which are fundamental for stabilizing the existing system and improving reliability/performance. Accordingly, the potential investment from NDPHC would be applied mainly towards refurbishing TCN assets and completing TCN's ongoing projects.

7. Network Capacity & Wheeled Energy

Network Capacity

32. Chart 3 below shows expected peak generation compared to the projected capacity of the transmission network to transmit the available generation to the DisCos. The total installed generation capacity is also shown; however a large portion of the installed generation is unable to produce power due to gas supply constraints. It is assumed that over time the gas constraints will be addressed, but gas constraints will probably continue to limit the peak generation on the system throughout the forecast period to 2020.

33. It should be pointed out that if gas availability for power generation were to increase rapidly in the next few years, the peak generation would catch up to the capacity of the installed generation that is already in service and outstrip the capability of the transmission system to wheel the energy. In this case, the capacity of the transmission system might become the bottleneck for serving load.

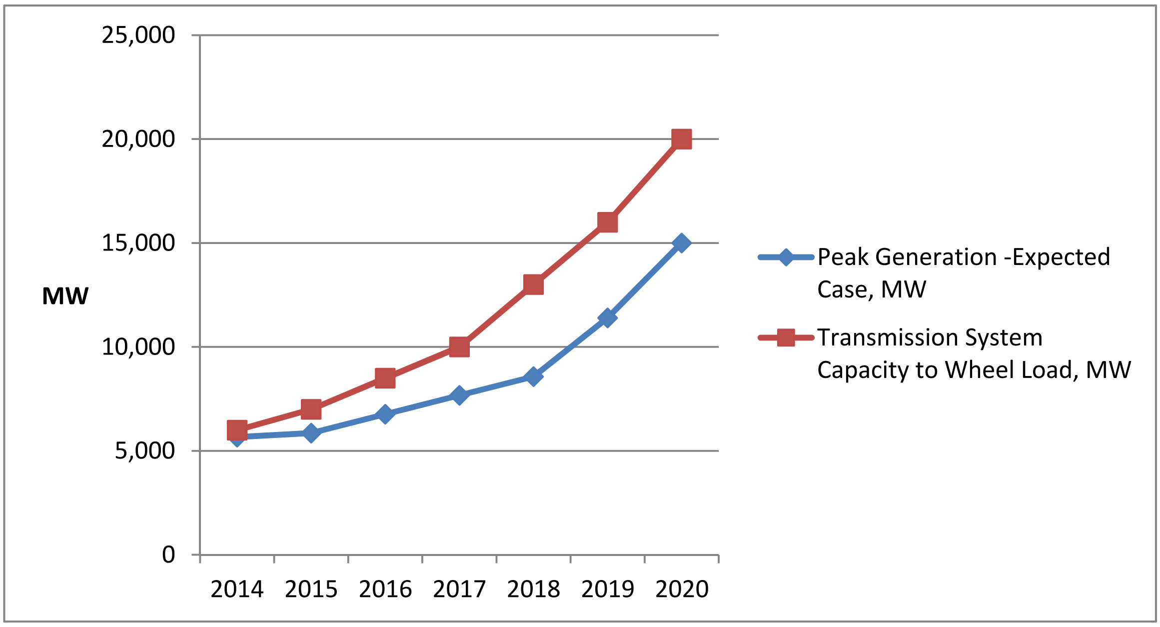

Chart 3: Available Generation Comparison with Transmission Capability 2014-20

Wheeled Energy

34. The projected wheeled energy (sent out by stations), transmission losses and bulk supply to DisCos over the next five years to 2018 under the "Expected" Case is indicated in Chart 4 below.

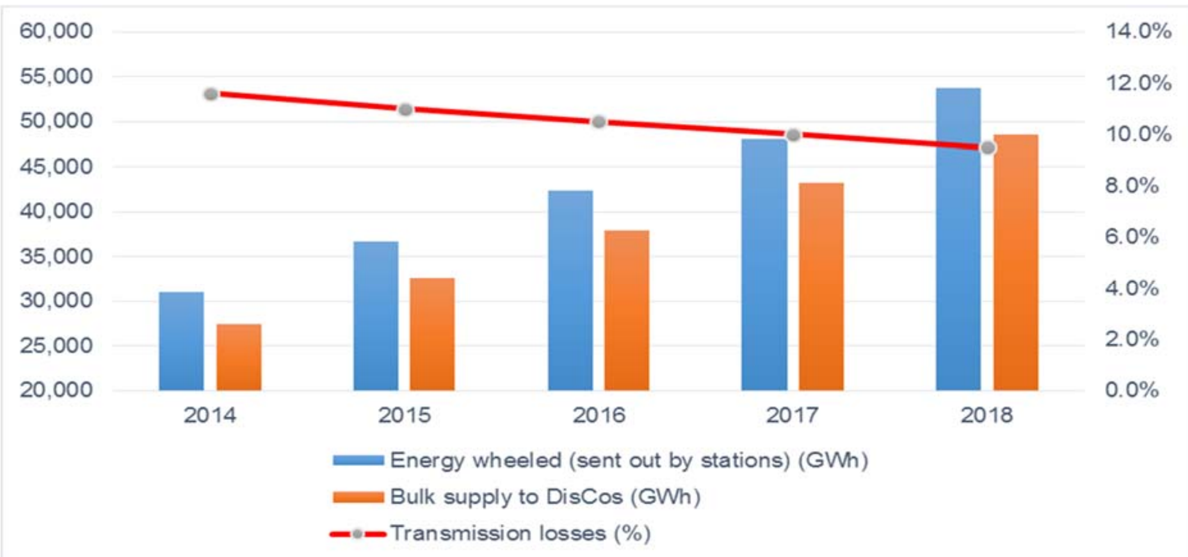

Chart 4: Wheeled Energy & Bulk Supply 2014-18

35. Energy wheeled (sent out from stations) is forecast on the basis of constrained gas supply. The wheeled energy is projected to increase by 7.5% in

2014 and by 18.1% in 2015. The increases are due to additional generation capacities coming online.

Transmission Losses

36. Losses at the transmission level are segregated into technical, commercial and metering losses. Such losses are due to the following factors:

i) Technical Losses are caused by consumption of energy that is dissipated as heat in transformers and lines when electricity is wheeled through the system.

ii) Commercial Losses occur when there is unauthorised consumption of electricity at the transmission level, including theft by direct serve customers and unauthorized connections to substations.

iii) Metering Losses are caused by over-billing by generators for energy sent out at the generation trading points and under-billing of DisCos for bulk supply delivered to the distribution trading points. Such losses are incurred when the billed quantities shown in market invoices are over-stated (in the case of generators) or under-stated (in the case of DisCos), in comparison to the actual quantities delivered or consumed.

37. For tariff calculations, TCN proposes that NERC establish allowable loss factors for each component of losses (technical, commercial and metering) to determine the allowable aggregate losses that are charged to market participants. Allowable technical and commercial losses should be charged to the DisCos. Allowable metering losses should be charged to the market participant that is responsible for such losses. Generators are responsible for metering losses when they over-report quantities delivered at the trading points, and DisCos are responsible when they under-report quantities consumed at the trading points. The onus for such billing errors must be on the market participant, not the Market Operator, as the participant owns the trading point meters and ultimately has the duty to correct quantities shown on the market invoices issued by the MO if such quantities are incorrect.

38. Table 7-1 shows baseline losses for year 2013 and proposed allowable losses for 2014 and 2015, which are used for setting future year tariff levels. Allowable loss factors are determined using a two-step process: 1) determine the baseline losses with reference to historic data, and 2) adjust for future efficiency improvements mandated by NERC.

Table 7-1: Transmission Losses 2013-15

Category	Baseline for 2013	Proposed Allowable for 2014	Proposed Allowable for 2015	Required Efficiency Improvements compared to Baseline
Technical Losses	7.00%	6.75%	6.50%	0.25% in 2014 and 0.50% in 2015
Commercial Losses	0.30%	0.25%	0.20%	0.05% in 2014 and 0.10% in 2015
Metering Losses	4.84%	4.60%	4.30%	0.24% in 2014 and 0.54% in 2015
Aggregate Losses	12.14%	11.60%	11.00%	0.54% in 2014 and 1.14% in 2015

8. Operating Expenses 2014-2015

39. Table 8-1 below provides a summary of operating expenses for 2014-15 as per TCN's business plan, together with actual expenses incurred in 2013. Details of the operating expenses of each Business Unit are provided in Annex 1.

Table 8-1: Operating Expenses 2013-15 (in Nominal NGN millions)

	Actual	Business Plan Forecast							
	2013	2014				2015			
	TCN	TSP	SO	MO	TCN	TSP	SO	MO	TCN
Payroll	15,495	11,505	7,161	461	19,126	13,178	10,650	593	24,420
Repairs & maintenance	6,108	17,403	3,622	21	21,045	21,403	3,890	24	25,316
Administration & overheads	4,978	4,479	2,570	376	7,425	4,789	2,804	436	8,029
Total Operating Expenses	26,581	33,386	13,352	858	47,596	39,369	17,344	1,052	57,765
% increase over previous year					79%	18%	30%	23%	21%

40. The operating budget is based upon the individual requirements built up by each Business Unit including staffing escalation to coincide with the increase in capacity of the network as well as the acquisition of the NIPP assets in 2014. Emphasis has been specifically directed towards maintenance costs to enable current and future assets to function at their highest possible capacity.

41. Payroll costs are built up from headcount using 2014 salary by labour category, plus allowance for benefits as per historic and future expectations based on percentages of salary. Headcount reflects the rightsizing exercise of 2013, which eliminated approximately 600 positions from TCN. In late 2013, TCN concluded a recruitment process which saw approximately 500 new technical positions filled.

42. Repairs and maintenance cover the comprehensive list of line maintenance, substation maintenance, SCADA maintenance, communications maintenance and related engineering services.

43. TCN is currently operating on a Minimum Funding budget and this will continue until the new tariffs, as applied in this filing, are implemented or Government support is extended to cover the additional operating costs. Refer to Sections 11 and 12 for further details.

9. Methodology, Inputs and Results

Pricing Methodology& Tariff Components

44. The pricing methodology adopted by NERC in the MYTO 2 tariffs has been used in this tariff filing.

45. Transmission tariffs are made up of the following components of TCN's revenue requirements:

i) Operating expenses excluding provisions for depreciation and uncollected billings,

ii) Return on asset base (working capital employed and fixed assets in service), and

iii) Depreciation of fixed assets in service.

Ancillary Services & Regulatory Charges

46. Although the ancillary and NERC's regulatory charges of 1.5% on the TSP/SO/MO component of the tariff form part of the overall transmission tariff and the revenues and matching costs are reflected in TCN's income statements they do not impact on TCN's cash flows as they are paid over directly by the Market Operator to the GenCos and NERC (i.e. the revenues and costs are in and out of TCN's income statements). Such costs are therefore not considered in this tariff submission.

47. It is to be noted that the latest cost estimates for ancillary services prepared by the Nigeria Infrastructure Advisory Facility (NIAF) are much higher than MYTO 2 estimates.

Macro-economic Assumptions

48. Table 9-1 below shows the assumptions made with respect to inflation and the Naira/US$ exchange rate.

Table 9-1: Macro-economic Assumptions

	2014	2015	2016	2017	2018
Nigeria inflation (CPI), as per CBN	8.19%	7.00%	7.00%	7.00%	7.00%
US Inflation (CPI), as per IMF	1.51%	1.78%	1.95%	2.14%	2.22%
Exchange rate (NGN/US$):					
Average in year	157.1	161.1	165.1	169.2	173.5
At December 31	159.1	163.1	167.1	171.3	175.6

Weighted Average Cost of Capital (WACC)

49. The weighted average cost of capital (WACC) of 11% is used to determine return on the asset base for calculation of transmission tariffs. The relevant figures, as per MYTO 2 estimates and calculations, are shown below.

i) 70:30 debt: equity

ii) debt interest: 9.73%

iii) equity return: 14% (10% market premium + 4% risk free rate)

iv) WACC (real pre-tax) = 11.014% (0.70 x 9.73% + 0.30 x 14%).

Asset Base & Return

50. Table 9-2 below shows the make-up of the asset base and return for 2013-15.

Table 9-2: Asset base & Return 2013-15 (in Nominal NGN millions)

	Actual	Business Plan Forecast							
Asset Base	**2013**	**2014**				**2015**			
	TCN	**TSP**	**SO**	**MO**	**TCN**	**TSP**	**SO**	**MO**	**TCN**
Working capital									
No. of months' Opex	2	2	2	2	2	2	2	2	2
Amount of working capital	4,429	5,564	2,225	143	7,933	6,562	2,891	175	9,628
Opening historical net book value of fixed assets in service (Note 1)	204,389	271,522	4,739	651	276,912	594,004	3,768	518	598,290
Additions in year at cost (Note 1)	12,012	26,982	471	65	27,518	57,225	1,190	415	58,829
PHCN & NIPP assets transferred in year	71,990	310,400	0	0	310,400	0	0	0	0
Adjustment for NIPP assets transfer in year	0	(232,800)	0	0	(232,800)	0	0	0	0
Fixed assets base	288,392	376,104	5,209	716	382,030	651,229	4,957	933	657,119
Asset Base to earn a return	292,793	381,669	7,435	794	389,898	657,791	7,848	693	666,332
Return									
Return on Asset Base (Real pre-tax WACC as per NERC estimates)	11.014%	11.014%	11.014%	11.014%	11.014%	11.014%	11.014%	11.014%	11.014%
Total Return	32,249	42,038	819	87	42,944	72,450	864	76	73,391
Note 1: Fixed assets are brought into service at beginning of each year and the return is therefore calculated on the opening historical net book value plus additions in year at cost.									

51. The asset base and return is composed of working capital and fixed assets in service. The working capital employed is assumed as two months' of annual operating expenses excluding provisions for depreciation and uncollected billings.

52. The basis of valuation of fixed assets in service is as follows:

i) Starting balance as of end 2010 based on NERC's MYTO 2 ODRC (Optimised Depreciated Replacement Cost) valuation of NGN 189 billion (US$ 1.22 billion), plus

ii) Asset additions 2011-13 (at cost), as recorded in TCN's books, plus

iii) Asset additions 2014-15, as forecast, plus

iv) Transfer of assets from PHCN on December 31, 2013 (assumed date) of NGN 72 billion (US$ 464 Million), as reported in PHCN books, plus

v) Transfer of NIPP asset on October 1, 2014 (assumed date) of NGN 310.4 billion (US$ 2 billion). The asset value and transfer date of NIPP transmission facilities are uncertain, plus

vi) Fixed assets (WB funded NTDP and NEDP) recorded in the Project Management Unit (PMU) of TCN up to 2012 and not reflected in TCN's books. These assets, amounting to NGN 23.4 billion (US$ 151 million), brought into TCN's fixed assets base and reflected in the opening balance as at January 1, 2013. Appropriate depreciation is provided when these assets were put into service.

53. Plant & machinery (major capital expenditure) are transferred to fixed assets in service three years after project commencement and all other fixed assets are put into service in the year following the year of expenditure. Table 9-3 below shows the make-up of fixed assets transferred from work-in-progress to fixed assets as they are put into service (i.e. additions to fixed assets) in 2013-15.

Table 9-3: Additions to Fixed Assets 2013-15 (in Nominal NGN millions)

	Actual	Business Plan Forecast							
	2013	2014				2015			
	TCN	TSP	SO	MO	TCN	TSP	SO	MO	TCN
Plant & Machinery	11,118	26,982	471	65	27,518	26,982	471	65	27,518
Land & Buildings	695	0	0	0	0	16,589	0	0	16,589
Helicopters	0	0	0	0	0	5,767	0	0	5,767
Furniture & Fittings	104	0	0	0	0	1,830	543	239	2,612
Motor Vehicles	95	0	0	0	0	6,057	175	111	6,343
Total Additions to Fixed Assets	12,012	26,982	471	65	27,518	57,225	1,190	415	58,829
of which:									
WIP at December 31, 2013	12,012	26,982	471	65	27,518	26,982	471	65	27,518
New expenditure:	0	0	0	0	0	0	0	0	0
Plant & Machinery	0	0	0	0	0	0	0	0	0
Land & Buildings	0	0	0	0	0	16,589	0	0	16,589
Helicopters	0	0	0	0	0	5,767	0	0	5,767
Furniture & Fittings	0	0	0	0	0	1,830	543	239	2,612
Motor Vehicles	0	0	0	0	0	6,057	175	111	6,343
Total New Expenditure	0	0	0	0	0	30,243	719	350	31,312
Total Additions to Fixed Assets	12,012	26,982	471	65	27,518	57,225	1,190	415	58,829

Depreciation

54. Table 9-4 below provides a summary of depreciation of fixed assets in service for 2013-15.

Table 9-4: Fixed Assets Valuation & Depreciation 2013-15 (in Nominal NGN millions)

	Actual	Business Plan Forecast							
	2013	2014				2015			
	TCN	TSP	SO	MO	TCN	TSP	SO	MO	TCN
Existing fixed assets at 12/31/2010 (ODRC Valuation)	10,401	10,198	178	24	10,401	10,198	178	24	10,401
Fixed assets transferred from PHCN (assumed date 12/31/2013)	0	2,057	0	0	2,057	2,057	0	0	2,057
Fixed assets transferred from NIPP (assumed date 08/01/2014)	0	2,217	0	0	2,217	8,869	0	0	8,869
New assets since 1/1/2011 (excluding transfers from PHCN & NIPP)	1,079	1,829	32	4	1,865	4,710	135	52	4,897
Total Depreciation	11,480	16,301	210	29	16,540	25,834	313	77	26,224

55. Table 9-5 shows the asset lives have been assumed for the calculation of depreciation charges. The assumptions are line with those assumed in MYTO 2.

Table 9-5: Asset Lives for Depreciation

	Existing at 1/1/11 Years	Subsequent additions Years
Plant & machinery	20	35
Land & buildings	40	50
Helicopters	n/a	15
Furniture, fittings & office equipment	10	10
Motor vehicles	5	5

Summary Revenue Requirements

56. The overall transmission revenue requirements are summarized and illustrated in Table 9-6 and Chart 1 below.

Table 9-6: Tariff Revenue Requirements 2013-15 (in Nominal NGN millions)

	Actual	Business Plan Forecast							
	2013	2014				2015			
	TCN	TSP	SO	MO	TCN	TSP	SO	MO	TCN
Operating expenses excluding provisions for depreciation & uncollected billings	26,574	33,386	13,352	858	47,596	39,369	17,344	1,052	57,765
Return on Asset Base	32,249	42,038	819	87	42,944	72,450	864	76	73,391
Depreciation of Fixed Assets in Service	11,480	16,301	210	29	16,540	25,834	313	77	26,224
TCN component of revenue requirements	70,302	91,725	14,381	974	107,080	137,654	18,521	1,205	157,380
% increase over previous year					52%	50%	29%	24%	47%

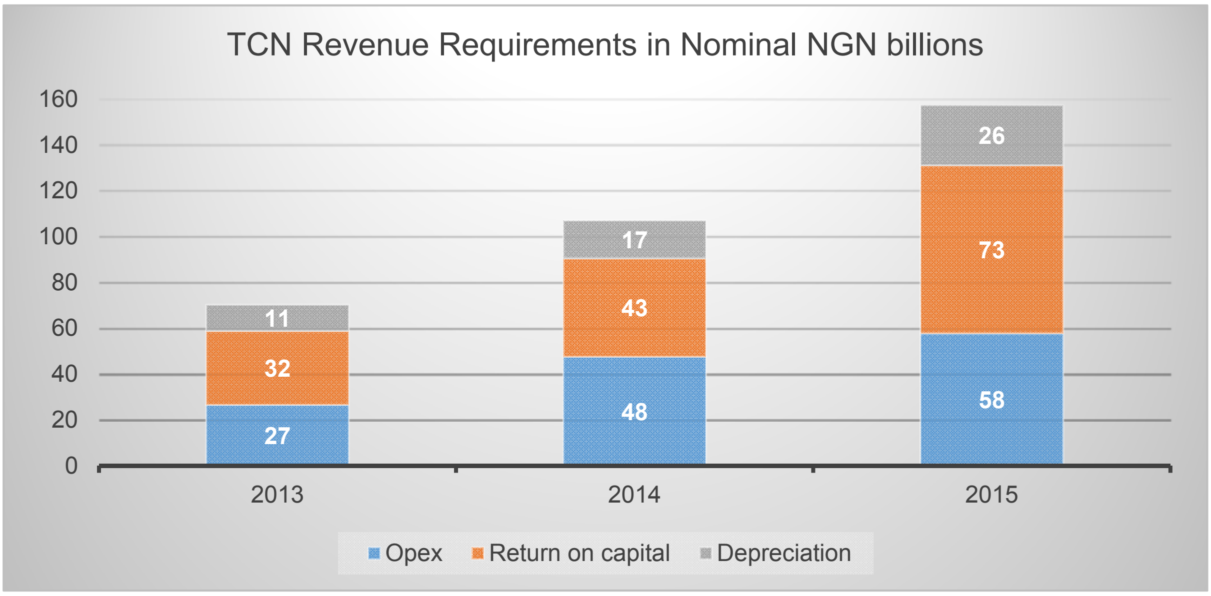

Chart 5: Components of Tariff Revenue Requirements 2013-15

57. No allowance is made for uncollected billings in the determination of transmission tariffs. Such costs therefore eat into the depreciation and returns provided for in the tariff.

58. The annual revenue requirements of TCN as per the above Business Plan are estimated at NGN 107 billion in 2014 and NGN 157 billion in 2015. Projected revenue requirements for 2015 are 2.25 times of MYTO 2 estimates, as indicated in Table 9-6 above.

10. Tariffs

Proposed Cost Reflective Tariffs

59. Table 10-1 below shows the proposed new fully cost reflective tariffs needed to meet the revenue requirements indicated in Table 9-6 above. The tariffs are stated both in terms of fixed monthly charges (TCN's recommended option) and variable energy costs.

Table 10-1: Proposed Cost Reflective Tariffs 2014-15

	Full Cost Reflective Tariffs							
	2014				2015			
	TSP	SO	MO	TCN	TSP	SO	MO	TCN
Fixed Monthly Charge (NGN millions)	7,644	1,198	81	8,923	11,471	1,543	100	13,115
OR								
Energy based Unit Rate (NGN/MWh)	3,342	524	35	3,901	4,220	568	37	4,824

60. The above energy based tariffs are projected on the basis of bulk energy supply to DisCos in 2014/15, as indicated in Table 10-2 below.

Table 10-2: Wheeling Capacity & Energy 2013-15

	2013	2014	2015
Wheeling capacity at Dec 31 (MW)	5,000	6,000	7,000
Wheeling capacity (MW) - average during year	5,000	5,500	6,500
Peak generation (MW)	4,458	4,962	5,858
Average generation (MW)	3,297	3,544	4,184
Growth in peak generation	-1.3%	11.3%	18.1%
Energy wheeled (sent out by stations) (GWh)	28,879	31,048	36,654
Growth in energy sent out	0.0%	7.5%	18.1%
Transmission losses (%)	12.1%	11.6%	11.0%
Bulk supply to DisCos (GWh)	25,373	27,446	32,622

Annual Energy Adjustment Clause

61. An annual energy adjustment mechanism needs to be put in place if transmission tariffs continue to be linked to energy throughput. Any under or over recovery of TCN's fixed costs (basically all of TCN's revenue requirements) arising as a result of variances between estimated and actual wheeled energy should be accounted for in the subsequent year's tariff setting. Such a mechanism is necessary to ensure that TCN does not derive any financial benefits or suffer any

financial losses as a direct result of energy related issues that are outside its control. However, from the customers' perspective, such approach will give rise to inter-generational inequity.

Cost Reflective Tariffs vs. MYTO 2 Tariffs

62. Table 10-3 and Chart 6 below compare the latest estimates of fully cost reflective tariffs with MYTO 2 tariffs for 2014 and 2015. The latest estimated tariffs reflect in full the amounts needed to adequately maintain and operate the network and to grow the infrastructure in step with rapid expansion of generation and load. The resulting tariffs are significantly higher than existing MYTO 2 tariffs, as shown in the following table and chart.

Table 10-3: Cost Reflective & MYTO 2 Tariffs 2014-15

	2013	2014	2015	2014	2015
				% change	
Bulk supply to DisCos (GWh)	25,373	27,446	32,622	8.2%	18.9%
TCN component of revenue requirements	70,302	107,080	157,380	52.3%	47.0%
TSP wheeling & SO/MO service charges (NGN/MWh):					
Cost reflective tariff (in calendar years)	2,771	3,901	4,824	40.8%	23.7%
MYTO 2 tariff (in calendar years)	1,407	1,355	1,419	-3.7%	4.8%
MYTO 2 tariff (in May each year)	1,462	1,367	1,346	-6.5%	-1.6%
Cost reflective vs. MYTO 2 (times)	1.97	2.88	3.40		
Cost reflective vs. MYTO 2 in May 2014 (times)		2.85	3.53		

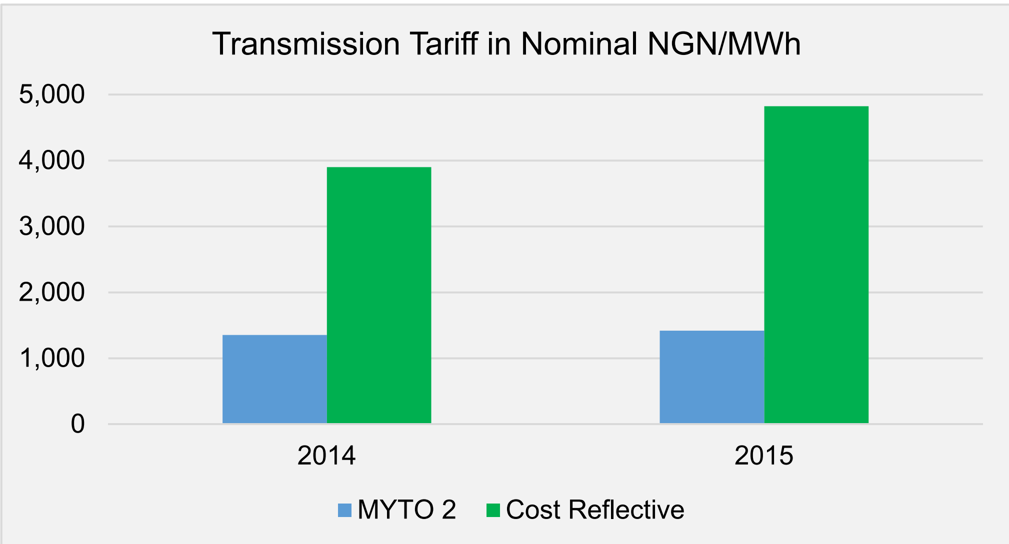

Chart 6: Cost Reflective & MYTO 2 Tariffs 2013-15

63. In terms of bulk energy supply, the average transmission tariff for TSP and each of SO and MO needs to increase from the present rate of 1,367 N/MWh to 4,824 N/MWh for TCN to achieve full cost recovery in 2015 which is a 3.53 times of TCN's existing average tariff. The proportion related to 2014 is 2.85 times. It is proposed that a one-time increase of 3.53 times of the present average tariff is

applied effective August 1, 2014 so as to avoid a second increase in January 2015. The surplus billing collections estimated at NGN 8 billion in 2014 relating to advancing the January 1, 2015 increase will be applied to the revenue deficiency for the first seven months of 2014 and will assist in clearing existing overdue liabilities.

64. In comparing the latest estimates with MYTO 2 figures, it is important to note that although the revenue requirements in 2015 are 2.25 times higher, the average transmission tariff in terms of bulk energy supply is 3.4 times higher. This wide difference illustrates the dilemma that TCN has faced since 2012 in under-recovery of its costs since MYTO tariffs were established.

65. MYTO tariffs are revised every June 1, as pre-determined in the MYTO 2 order. Transmission tariffs were reduced by 6.5% effective June 1, 2013. According to MYTO 2, tariffs would be reduced by 1.6% effective June 1, 2014 followed by an increase of 9.3% effective June 1, 2015.Accordingly, the automatic adjustments provided under MYTO 2 do nothing to address the large gap between MYTO II and fully cost reflective tariff levels.

66. The financial impact on TCN's annual revenues due to the inadequacy of the MYTO 2 tariffs is considerable. Table 10-4 below shows the financial impact in terms of revenue shortfalls in 2014-15. These shortfalls are forecast at NGN 70 billion (US$ 445 million) in 2014 and NGN 111 billion (US$ 690 million) in 2015.

Table 10-4: Revenue Shortfalls due to Inadequate Tariffs 2014-15

	NGN billions		US$ millions	
	2014	2015	2014	2015
Revenue Shortfalls	70	111	445	690

Impact on Retail Tariff

67. Based on the above calculations, TCN's component/share of the total existing sector revenue requirements will increase from 7% to 15%, assuming no changes to MYTO estimated revenue requirements of other market participants. The total tariff to distribution customers, including costs of generation, transmission, distribution and other services will increase by approximately 10%.

11. Cash Flows

68. Two alternative cash flow forecasts for 2014-15 are presented in Table 11-1 based on two tariff scenarios:

I. MYTO 2 tariffs to apply up to July 31, 2014 and the fully cost reflective tariffs, as proposed in this paper, to apply as from August 1, 2014, and

II. MYTO 2 tariffs to apply throughout.

69. All other assumptions are common to both cash flow forecasts. The key assumptions are summarized below:

- Energy wheeled (sent out from stations) is forecast on the basis of constrained gas supply, as detailed in Section 7 above.

- Minimum Funding (MF) budgets to apply for the first seven (7) months to July 2014. The MF budget has been developed to align with the low level of cash receipts.

- TCN Business Plan (BP) to apply for the remaining seventeen (17) months to December 2015. The BP, which has been adopted in deriving the fully cost reflective tariffs, is driven by the need to refurbish existing facilities, expand/reinforce the network, improve system operations and prepare for the Transitional Electricity Market (TEM). The budgets fully reflect the amounts needed to adequately maintain and operate the network and to grow the infrastructure in step with rapid expansion of generation and load. The budget amounts are significantly higher than past spending levels, reflecting the fact that in the past TCN has suffered from inadequate funding.

- Major capital investments of NGN 586 billion (US$ 3.7 billion) to be funded from external sources (loans, FGN appropriations and proceeds from NIPP's sale of GenCos) are excluded from the cash flows presented in the table below. Only investments to be funded from internally generated revenues (IGR) of NGN 15.5 billion (US$ 98 million) are considered.

- Billing collections are assumed at the actual rates of 57% in January 2014 and 45% in February 2014, and 45% from March to July 2014, and 70% for TSP and 60% for SO/MO from August to December 2014 and 100% throughout 2015 (MYTO assumes 100% collections throughout).

Table 11-1: TCN Summary Cash Flows 2014-15 (in Nominal NGN millions)

	Tariff Alternative I						Tariff Alternative II					
Assumed Transmission Tariffs>	MYTO 2	New		New			MYTO 2					
	2014			2015	2014-15		2014			2015	2014-15	
Budget Basis >	Jan-July Minimum Funding	Aug-Dec Business Plan	Total	Total Business Plan	Total	Total	Jan-July Minimum Funding	Aug-Dec Business Plan	Total	Total Business Plan	Total	Total
Energy wheeled (sent out) (GWh)	16,608	14,441	31,048	36,654	67,702		16,608	14,441	31,048	36,654	67,702	
Growth in energy sent out	9.8%	5.0%	7.5%	18.1%	26.9%		9.8%	5.0%	7.5%	18.1%	26.9%	
Transmission losses (%)	11.6%	11.6%	11.6%	11.0%	11.3%		11.6%	11.6%	11.6%	11.0%	11.3%	
Bulk supply to DisCos (GWh)	14,681	12,765	27,446	32,622	60,068		14,681	12,765	27,446	32,622	60,068	
Av tariff (NGN/MWh) (Note 1)	1,361	3,901	2,543	4,824	3,782	19.8	1,361	1,346	1,355	1,419	1,390	8.6
Average collection rate	47%	69%	56%	100%	88%		47%	69%	56%	100%	81%	
	NGN billion					US$ million	NGN billion					US$ million
Revenue billed	20.0	49.8	69.8	157.4	227.2	1,421	20.0	17.2	37.2	46.3	83.5	524
Other revenues	0.5	0.3	0.8	0.9	1.7	11	0.5	0.3	0.8	0.9	1.7	11
Total revenues billed	9.8	34.5	44.3	158.3	202.5	1,264	9.8	12.1	21.9	47.2	69.1	433
Operating expenses												
Payroll	(10.4)	(8.0)	(18.4)	(24.4)	(42.8)	(269)	(10.4)	(8.0)	(18.4)	(24.4)	(42.8)	(269)
Repairs & maintenance	(2.1)	(8.8)	(10.8)	(25.3)	(36.2)	(226)	(2.1)	(8.8)	(10.8)	(25.3)	(36.2)	(226)
Administration & overheads	(3.4)	(3.1)	(6.5)	(8.0)	(14.5)	(91)	(3.4)	(3.1)	(6.5)	(8.0)	(14.5)	(91)
Total Opex	(15.9)	(19.8)	(35.7)	(57.8)	(93.5)	(586)	(15.9)	(19.8)	(35.7)	(57.8)	(93.5)	(586)
Capital investments funded from IGR (Note 2)												
Needed investments	(5.3)	(3.8)	(9.0)	(6.9)	(15.9)	(100)	(5.3)	(3.8)	(9.0)	(6.9)	(15.9)	(100)
Investments deferred	4.8	(4.8)	0.0	0.0	0.0	0	4.8	(4.8)	0.0	0.0	0.0	
Investments - as forecast	(0.5)	(8.5)	(9.0)	(6.9)	(15.9)	(100)	(0.5)	(8.5)	(9.0)	(6.9)	(15.9)	(100)
Working capital requirements	2.5	(9.3)	(6.8)	(11.8)	(18.6)	(116)	2.5	(0.3)	2.2	(2.2)	(0.1)	(0)
Debt service & AFD liquidity facility	0.0	0.0	0.0	(3.6)	(3.6)	(23)	0.0	0.0	0.0	(3.6)	(3.6)	(23)
Cash Surplus/(Shortfall)	**(4.1)**	**(3.2)**	**(7.2)**	**78.1**	**70.9**	**439**	**(4.1)**	**(16.6)**	**(20.6)**	**(23.4)**	**(44.0)**	**(276)**
Opening cash balance	7.6	3.5	7.6	0.3	7.6	49	7.6	3.5	7.6	(13.1)	7.6	49
Exchange difference						(7)						4
Closing cash balance	3.5	0.3	0.3	78.4	78.4	481	3.5	(13.1)	(13.1)	(36.5)	(36.5)	(224)
Required MINIMUM Cash Balance (Note 3)	2.6	9.2	9.2	12.1	12.1	74	2.6	3.2	3.2	3.6	3.6	22
Surplus/(Shortfall) in Required Cash Balance	**0.8**	**(8.9)**	**(8.9)**	**66.3**	**66.3**	**407**	**0.8**	**(16.3)**	**(16.3)**	**(40.0)**	**(40.0)**	**(245)**
Cash Surplus/(Shortfall):												
NGN/MWh	**58**	**(696)**	**(324)**	**2,033**	**1,104**	**6.8**	**58**	**(1,275)**	**(593)**	**(1,227)**	**(666)**	**(4.1)**
As % of Av Tariff	**4%**	**-18%**	**-13%**	**42%**	**29%**	**34%**	**4%**	**-95%**	**-44%**	**-86%**	**-48%**	**-47%**

Note 1: Average tariff comprises of TSP wheeling and SO/MO service charges and excludes ancillary and NERC regulatory charges
Note 2: Underspending on IGR funded capital investments in the 1st half 2014 is deferred & disbursed in the 2nd half 2014
Note 3: Required minimum cash balance is assumed at 4 weeks' annual billed revenue

70. The bottom line projected results based on MYTO 2 tariffs indicate that there will be net cash outflows of NGN 20.6 billion in 2014 and NGN 23.4 billion in 2015. Cumulative cash shortfalls in the required minimum cash balance at end 2015 is projected to reach NGN 40 billion (US$ 245 million), assuming minimum cash holding of four weeks' annual billed revenues.

71. The projected cash shortfalls will have significant negative consequences for TCN's financial outlook. The cash shortfalls of US$ 245 million will need to be funded from government subsidy. TCN's financing costs will increase and TCN will find it difficult to raise funding for capital expenditures if tariffs are not adjusted effective August 1, 2014 and MYTO 2 tariffs continue to apply through to December 2015.

72. If the proposed tariffs are implemented effective August 1, 2014, the projected cash surpluses in 2015 (Alternative I tariff scenario) will be utilized towards investments so as to close the investment funding gap and reduce the borrowing requirement.

12. Impacts of Under-funding on TCN Operations

Operating Expenses

73. Table 12-1 below provides a summary of operating expenses in 2013 (actuals) and estimates for 2014-15 as per TCN's Business Plan (BP) and the Minimum Funding (MF) budget under which the company will continue to operate until until the new tariffs, as applied in this filing, are implemented or Government support is extended to cover the additional operating costs.

Table 12-1: Operating Expenses 2014-15 Business Plan vs. Minimum Funding (in Nominal NGN millions)

	Actual	BP	MF	MF vs. BP	BP	MF	MF vs. BP
	2013	2014			2015		
Payroll	16,551	19,126	17,828	93%	24,420	20,056	82%
Repairs & maintenance	6,108	21,045	3,553	17%	25,316	3,997	16%
Administration & overheads	3,914	7,425	5,835	79%	8,029	6,564	82%
Total Operating Expenses	26,574	47,596	27,216	57%	57,765	30,617	53%
% increase over 2013		79%	2%		117%	15%	

74. The operating expenses are discussed in more detail in the individual Business Unit plans provided in Annex 1.

75. TCN is operating at less than 60% of its full operational requirements. The rationale for the business plan (full funding) and the consequences of operating under the constrained cash (minimum funding) environment are summarized below.

76. <u>Payroll (NGN 19.1 & 24.4 billion required in 2014/15; 93% & 82% funded)</u>: TCN's staffing requirements are mainly a function of the size and scope of utility operations. Headcount reflects the rightsizing exercise of 2013, which eliminated approximately 600 positions from TCN. In late 2013, TCN concluded completed a major initiative to align its staff strength with the demands of the business, a recruitment process which saw approximately 500 new technical positions filled. The current staffing levels are in line with operating requirements and reducing staff is not advisable or possible in 2014. Payroll is a non-discretionary business expense, and workers are paid in priority to other operating expenses.

77. Accordingly, there is no possibility to reduce payroll expenses in 2014. For 2015, there are multiple ongoing initiatives that will require TCN to increase staff strength, including handover of the NIPP transmission assets to TCN, project management for large scale refurbishment and expansion of the transmission system and unbundling of headquarters shared services to the TSP, SO and MO business units. However, unless minimum funding constraints are addressed through tariff increase or other means, TCN may need to impose limitations on new hires, with dire consequences for the above listed initiatives.

78. <u>Repairs & Maintenance (NGN 21.0 & 25.3 billion required in 2014-15, 17% & 16% funded)</u>: The repairs and maintenance budget in the business plan cover the

comprehensive list of line maintenance, substation maintenance, SCADA maintenance, communications maintenance and related engineering services. In view of the cash constraints over the years, TCN has not been able to maintain and operate the network to the required standards. The business plan expenditure estimates are based on a study conducted by NIAF and supported by a spreadsheet model prepared by them. Lack of maintenance of the network over the past two decades has adversely impacted on system security, reliability and delivery.

79. Administration and Overheads (NGN 7.4 & 8.0 billion required; 79% & 82% funded): The major items include vehicle expenses, transport and travel, insurance, security services, office rent, training, consultancy fees, board of directors' costs, WAPP costs, management fees and costs of milestone deliverables.

Capital Investments

80. Table 12-2 below shows the forecast capital investments relating to motor vehicles, office furniture, equipment, tools and other small capital items to be funded from internally generated revenues (IGR) in 2014-15 as per TCN's Business Plan (BP) and the Minimum Funding (MF) budget under which the company will continue to operate until until the new tariffs, as applied in this filing, are implemented or Government support is extended to cover the additional capital investments. TCN will not be in a position to finance any investments relating to the larger investment projects from its internal resources in 2014-15.

Table 12-2: IGR Funded Capital Investments (in Nominal NGN millions)

	BP	MF	MF vs. BP	BP	MF	MF vs. BP
	2014			2015		
Office furniture, equipment, tools, etc	2,612	549	21%	4,330	1,918	44%
Motor Vehicles	6,431	333	5%	2,554	2,189	86%
Total IGR funded Investments	9,043	882	10%	6,884	4,107	60%

81. The above figures clearly illustrate that the much needed investments in vehicles and other capital items will have to be severely curtailed in 2014-15 if the present transmission tariffs are not revised upwards. Approximately 10% and 60% of such investment requirements are funded under existing tariffs.

ANNEX 1: Business Plans for TCN Business Units

1. Business Plan for Transmission Services Provider

Introduction to TSP

Transmission Services Provider Business Unit is the owner of the transmission network responsible for maintaining and constructing lines and substations. TSP is responsible for providing electricity transmission services in cost effective, efficient and reliable way. TSP carries out different maintenance activities in addition to planning, designing, procuring and implementing massive transmission grid expansion program.

Need for Reinforcement and Expansion of the Grid

There are multiple business drivers that create an urgent need to expand the delivery capability and improve the reliability of the transmission system:

- The existing transmission system, which is capable of delivering about 7,000 MW of generation to the DisCo Trading Points, is inadequate to meet expected growth with NIPP and various IPP generation projects coming on line.
- NBET's PPAs with Successor Company GenCos and new IPPs provide for a large amount of new and refurbished generation projects that will be developed in the coming years with the expectation that TSP will expand its network to wheel the power to the DisCos.
- The existing system cannot support the anticipated growth in per capita usage and the expected substantial growth in customers in all classes. If the system is not expanded it will negatively impact the country's potential to increase its GNP.
- The system has limited redundancy in its design and experiences an unacceptable number of total system blackouts. These blackouts impact customer, particularly commercial and industrial users, and have the real potential of making Nigeria a less attractive country to start a new business or expand an existing business.
- Existing substations and lines are in desperate need of refurbishment, as past funding of TCN's capital requirements has not kept pace with the need for refurbishment.

Accordingly, TSP needs to implement an ambitious program of transmission improvements. A major refurbishment program for lines and substations is required in 2014-15 to restore existing facilities to full capability and address reliability issues.

In addition, new line and substation projects must be built to increase the load carrying capability of the network in line with the expansion of the generation sector. The primary targets are to increase the current capacity of the grid from 7 GW at present to 10 GW by 2017, and to 20 GW by 2020.

TCN has conducted extensive planning and engineering studies to develop an optimal expansion plan to meet the targets. For the period 2014-15, TCN will focus mainly on refurbishing existing facilities to restore the network to its original capacity, finishing projects that are in various stages of construction, and initiating the construction of over 120 new lines and substations to expand the network to a total load carrying capability of 10,000 MW. Projects will be completed in phases according to the schedule shown in Table 1-1.

Table 1-1: TSP Targets for Transmission Refurbishment and Expansion

Item	USD Mln ($)	GW Target	In Service
Capital Refurbishment	$947	-	2015
Projects under Construction	$989	7-8,000	2015
Expand to 10 GW; increase reliability	$2,235	10,000	2017
Expand from 10 GW to 13 GW	$1,570	13,000	2018
Expand from 13 GW to 16 GW	$1,000	16,000	2019
Expand from 16 GW to 20 GW	$1,000	20,000	2020
Total: 2014-18	$7,742		

Capital Budget

Table 1-2 shows the budgeted costs of TSP capital expenditures for 2014 to 2018 by program in 2013 US$ millions and in equivalent nominal NGN millions.

Table 1-2: TSP Capital Investment Plan 2014-18

Capital Investments	2014	2015	2016	2017	2018	2014-18
In 2013 US$ millions						
Substation Refurbishment	568	237	47	47	47	947
New Lines and Substations	495	2,059	1,434	1,271	1,086	6,345
Land & Buildings	104	104	20	20	20	268
Helicopters	37	0	0	0	0	37
Office Tools, Furniture & Equipment	11	12	4	3	3	34
Motor Vehicles	38	13	10	10	10	80
Total Investments	1,254	2,425	1,515	1,351	1,166	7,711
In Nominal NGN millions						
Substation Refurbishment	90,605	39,384	8,231	8,617	9,029	155,866
New Lines and Substations	79,027	342,671	249,421	231,359	207,071	1,109,549
Land & Buildings	16,589	17,306	3,478	3,641	3,815	44,830
Helicopters	5,767	0	0	0	0	5,767
Office Tools, Furniture & Equipment	1,830	2,064	626	596	617	5,733
Motor Vehicles	6,057	2,188	1,695	1,775	1,860	13,575
Total Investments	199,875	403,613	263,451	245,988	222,392	1,335,320

Table 1-3 lists the additions for the Land and Buildings Category. TCN needs to set up Regional Stores where an emergency section is provided with adequate supplies of materials. These facilities are needed to support the expansion of the network and the maintenance and constructions needs of the regions. Currently TSP field staff has to lift materials from Lagos which is neither cost effective nor efficient. The cost of setting up of the Regional Stores is reflected in the budget. It is planned to complete the exercise within 15 months starting from the availability of funds.

Table 1-3: TSP Additions to Land and Buildings 2014-15

Item	Number
Regional Warehouses/Stores	8
Transformer Reclamation Workshop	1
Regional Manager Offices	8

Table 1-4 shows TSP vehicle additions. With expansion of the network and transfer of NIPP facilities to TSP, many new vehicles will be needed in 2014-15. Currently there is a need to purchase a new fleet of heavy duty maintenance vehicles that will have the capabilities to reach the off-road and remote locations in the grid to ensure proper maintenance is conducted in the most efficient manner. Specialized Utility Vehicles like bucket trucks and cranes must be purchased in order to carry out the planned maintenance throughout the grid with 8 expected vehicles in 2014, with expected replacement every 5 years. There is an urgent need for providing logistical resources to the field staff for carrying out massive maintenance works at the work stations and line patrols. A provision is therefore kept in the budget to provide vehicles to enhance mobility. Heavy utility trucks are also planned to be procured for each of the eight TSP Regions across the country. All vehicles will be equipped with safety equipment, tools and communication facility.

Table 1-4: TSP Vehicle Additions

Vehicle Fleet	2014	2015
TSP Maintenance Vehicles	200	120
TSP Utility Vehicles	8	
TSP Other Vehicles	103	52

TSP plans to acquire two new helicopters in November 2014 at a cost of US$ 36.7 million with FGN funding. TCN can substantially improve its capability of effectively performing transmission line maintenance, repair and construction activities with the use of these helicopters.

Operating Expenditure Budget

Table 1-5 shows the TSP operating expenditures budget for 2014-15 in nominal NGN millions. TSP requires operating budget for payroll, lines & substation maintenance, and other administration related overheads. Annual maintenance plans are currently being implemented by TSP staff. However, there are times when major overhaul or repairs of transformers are required at a dedicated facility. It is envisaged to have a Transformer Reclamation Workshop for the first time in the country.

Table 1-5: TSP Operating Expenditures 2014-15

Operating Expenses **In Nominal NGN millions**	2014	2015
Payroll	11,505	13,178
Repairs & maintenance		
Lines	5,378	6,689
Substation, transformers & switchgear	5,339	6,232
Electrical & mechanical equipment	3,820	4,367
Communications and SCADA	75	85
Line traces & erosion control	1,876	2,257
Survey fees & expenses	352	418
Helicopter operation & maintenance	136	874
All other	425	480
Total repairs & maintenance	17,403	21,403
Administration & overheads	3,308	3,516
Milestone Deliverables	616	675
Management Fees	555	598
Total operating expenses	33,386	39,369

A breakdown of the repairs and maintenance budget is shown in the above table. Currently there are approximately 10 power transformers that require to be repaired which require specialized equipment and training. Appropriate funding is provided in the budget for setting up of a new transformer reclamation facility. Provision is also made for the operations and maintenance of the two new helicopters as from November 2014.

Staff Strength

Table 1-6 shows the TSP headcount for 2013-15. The increase in staff of 420 for 2014-15 is due to the transfer of NIPP facilities to TCN and commissioning of new TCN facilities.

Table 1-6: TSP Staff Strength

Business Unit	Current	2014	2015
TSP	2598	2808	3018

2. Business Plan for System Operator

Introduction to System Operator

The System Operation department ensures integrated operation of the power system in Nigeria. All generating plants, distribution companies and the Transmission Service Provider are stakeholders of SO. The main responsibilities of SO include:

- Monitoring of system parameters and security.

- Ensure integrated operation of the power system to deliver quality uninterrupted power.
- Facilitate merit order dispatch.
- Facilitate the operation of the power market through bilateral exchange.
- Undertake power system studies, comprehensive system planning and contingency analysis.
- Augmentation of telemetry, computing and communication facilities.

The power system in Nigeria underwent 22 collapses in 2013 which is mostly due to unavailability of Spinning Reserve, Voltage Control, Automatic Under Frequency Load Shed Scheme (AUFLS) etc.

Going forward SO with support of the Ministry, are actively coordinating with generators to put spinning reserve in place with a target of 10% of available generation. The contract agreements to provide spinning reserve have been drafted and sent across to the generators. Since generation is plagued by gas supply constraint and maintenance issues, those generators with minimal gas constraint are being targeted. Simultaneously, black start agreements have been signed with the Shiroro, Ugelli and AES.

The three stage AUFLS has been implemented at 33KV & 132KV levels and is under test to come up with final settings to best save the system from collapsing in the face of zero spinning reserve. Once the final settings are zeroed down it will be intimated to the DISCOs for support. The next priority then would be to consider the option of putting the feeders on a rotational basis on AUFLS.

All the above which is expected to be fully implemented within Q2 2014, should bring down the system collapse figures to about half of 2013 besides reducing the grid down time due to lack of dependable black start facilities.

Capital Budget

The capital investment plan for SO for 2014 to 2018 in 2013 US$ millions and in equivalent nominal NGN millions is summarized in Table 2-1 below.

Table 2-1: SO Capital Investment Plan 2014-18

Capital Investments	2014	2015	2016	2017	2018	2014-18
In 2013 US$ millions						
SCADA restoration & expansion	0	34	0	0	0	34
Telecommunications improvement	26	0	0	0	0	26
Other plant & machinery	0	0	6	6	6	18
Land & Buildings	0	40	0	0	0	40
Office Tools, Furniture & Equipment	3.4	2.0	0.6	0.6	0.6	7
Motor Vehicles	1.1	1.5	1.9	2.3	2.7	10
Total Investments	30	76	7	7	7	125
In Nominal NGN millions						
SCADA restoration & expansion	0	5,603	0	0	0	5,603
Telecommunications improvement	4,181	0	0	0	0	4,181
Other plant & machinery	0	0	1,043	1,092	1,144	3,280
Land & Buildings	0	6,656	0	0	0	6,656
Office Tools, Furniture & Equipment	543	338	106	104	109	1,201
Motor Vehicles	175	250	330	419	515	1,689
Total Investments	4,900	12,847	1,480	1,615	1,768	22,611

The SO needs to undertake the following major new projects in 2014-15, in addition to expenditures for basic office and transport needs:

- SCADA Restoration and Expansion: $34 Million
- Telecoms improvement project: $26 Million
- New Control Center Building at NCC: $40 Million

The following sections provide the justification for the required capital expenditures.

SCADA and Telecom

The present SCADA system (World Bank 2009 project) is mostly dysfunctional and is being made to somehow serve the purpose with reactivation contracts. Further, since 2009 till date, new generating stations and substations have been added into the power system, which are not connected to the SCADA system through RTUs. So a new modern SCADA system is required and once it is implemented it has to be maintained and updated. The cost towards the new SCADA system has been captured in the Capital budget while the cost towards maintaining and updating the system besides providing for spares is captured in the Operating budget. The project to have a new SCADA system will take eighteen months from placing orders to successful commissioning.

The voice and data communication is done through optic fibre, micro wave and PLCC. This system is radial which makes it very vulnerable to outages. Hence it is planned to make a ring network configuration encompassing the new and old stations, so that in case of any outage there is always an alternate path available. Secondly the identified weak links need to be revamped for seamless communication for the SCADA system. Thirdly many new stations which have come up are not effectively covered through a communication link. Lastly we need to put in place a hotline voice communication from NCC to other control centers or stations of DisCos and GenCos without which real time operation of the power system is highly vulnerable with dependency on GSM network.

All these need to be completed in phases so that we have an effective communication system in place. The costs for implementation and maintaining the communication system is captured in the Capital and Operating budgets respectively. If funded, the entire communication system upgrade project will take around eighteen months to commission.

New Control Centre Building at NCC

The control center building at Oshogbo is in a dilapidated state and is very small from the perspective of housing up all the SCADA & Telecom servers and maintenance tools besides having the viewing gallery and control room for real-time operation and setting up scheduling desks for TEM. So it is planned to build a new control room within the stretch of available land in Oshogbo.

The $40 million cost for the same is captured in the Capex budget under Land & buildings. The project to have a fully functional new control centre building will require around fifteen months.

Vehicles

Presently SO has 103 operable motor vehicles both at headquarters and at sites. Some of these vehicles require replacement and with the increase in staff count and new areas of operation it will be pertinent to have few new vehicles placed for smooth execution of the work.

The cost for procuring the new vehicles is captured under Capital budget while fuelling and maintenance has been captured under Operating budget.

Operating Expenditure Budget

Table 2-2 shows the SO operating expenditures by major cost item. Budgets for Office Tools, Furniture & Equipment and Motor Vehicles are developed using bottom-up method for 2014-15.

Table 2-2: SO Operating Expenditures 2014-15

Operating Expenses	2014	2015
In Nominal NGN millions		
Payroll	7,161	10,650
Repairs & maintenance		
Communications and SCADA	3,363	3,598
All other	259	292
Total repairs & maintenance	3,622	3,890
Administration & overheads	1,748	1,910
Milestone Deliverables	432	474
Management Fees	389	420
Total operating expenses	13,352	17,344

Table 2-3 shows the breakdown of SO maintenance costs.

Table 2-3: Breakdown of SO Maintenance Costs in Constant Prices

Activity	USD Millions ($)		Naira Millions (N)	
	2014	2015	2014	2015
SCADA Spare Parts	3.3	3.3	513	513
SCADA Service Fee	5.5	5.5	850	850
Telecom Spare Parts	6.4	6.4	1,000	1,000
Telecom Service Fee	6.4	6.4	1,000	1,000
Total	21.6	21.6	3,363	3,363

Staff Strength

Presently the SO Business Unit has a headcount of 1,250 staff comprising of technical, non- technical and a few support staff, including the new recruits. The staff count is envisaged to go up to 1,668 by end of 2014 and to 2,234 by end of 2015 due to the following factors:

- New substations will be handed over to SO for operation by NIPP. TSP and SO will be required to provide personnel for 24x7 operations of the same.
- Prior to implementation of TEM, we are required to set up a new team for carrying out the activities related to TEM which is an entirely new function. This will also include manning the scheduling desk at NCC 24x7.
- With ring-fencing under progress to finally unbundle TCN, SO has to have its own set up in terms of support staff across all work centers in the eight electrical regions of the country besides the NCC, SNCC and 2 RCCs as against sharing with TSP.
- The Power System Planning department and Regulatory department are presently shared by TSP and SO. With ring-fencing, both will need to have separate departments, so it will involve employing new manpower with requisite experience.
- The cost towards meeting the salary requirements and other staff costs for above has been captured under Payroll. Similarly the cost towards setting up and maintaining new office space, refurbishing old office space and all admin costs have been captured in the Capital and Operating budgets under line items Office tools, Furniture and Equipment and Admin and Overheads.

Note on SO Tariff Charges

It should be noted that in 2013, 4.7 Billion Naira was due to be paid from the Market Fund to SO based on the tariff and total energy wheeled. Through December 2013, SO received 2.3 Billion Naira, resulting in a shortfall of 2.4 Billion Naira due to the low contribution by the DisCos to the Market Fund. The overall collection rate for SO for the year was around 50%.

3. Business Plan for Market Operator

Introduction to MO

The Market Operator is the Nigerian electricity market administrator designated for the implementation of the Market Rules. The MO has been administering the Pre-Transitional Stage of the market since the formal inception of the organized electricity market in 2004. The Market Rules require the MO to operate in a manner that guarantees efficiency, transparency and non-discriminatory market administration service to all Participants.

The MO is responsible for the following duties:

- Review the efficiency and adequacy of Market Rules and Market Procedures and propose such amendments as may be required to ensure their efficacy and adequacy;
- Admit & Register Participants; organise and maintain a Participants' Register; centralise the Information required for market administration, and organise and maintain the related data bases;
- Verify that each Connection Point (Trading Point) where a Participant injects or extracts energy has proper commercial metering related to physical exchange (injection and consumption) of energy, provision of Ancillary Services and other necessary commercial transactions;
- Manage the market settlement process, including preparation and transmittal of market invoices to Market Participants, revenue collection from DisCos, payment to services provides (MO, SO, NBET, NERC), finance and banking, and dispute resolution related to settlements and contract quantities.

Regarding commercial metering of contract quantities, adequate commercial metering of the Trading Points has been achieved by the MO, with 99% of the Trading Points metered by Grid Code-compliant digital meters. The MO has developed a system for remote meter reading and automatic data validation and correction, which consists of telecommunications using the GLO GPRS Network and a data collection system developed around the General Electric MV-90 platform. Meter reprogramming for the purposes of automated meter reading (AMR) is ongoing in the field. Other priority activities for metering include improving redundancy and resilience at the AMR Hub, improving the AMR workstation, acquisition of an automated system to calculate meter loss factors, upgrading AMR for GPRS communication mode, and increasing the number of meters currently read by the AMR system (50%) to 100% coverage.

The MO intends to continuously improve its processes, systems and infrastructure in line with best international practices. The MO has developed settlement software tools that produce the market invoices and address the energy imbalance in the monthly settlement statement issued by the MO. (Energy imbalance results when there is a variation between the DisCo's contractual share of the total energy delivered to the TCN-DisCo interface vis-à-vis its actual load drawn for the month.)

Other ongoing activities include development of a website portal to streamline the interface with Market Participants, and development and implementation of new procedures for metering, settlement and payments in line with the requirements shown in the Market Rules for the Transitional Electricity Market, which is set to kick off in 2014.

Budget

Table 3-1 and Table 3-2 show the MO CAPEX and OPEX budgets in dollars and Naira. The MO capital budget includes a major project in 2015 to upgrade settlement systems and tools. The project is expected to achieve the following goals:

- Improve telecommunications and website interface to automate and streamline business processes for meter data collection and settlements;
- Improve ICT in line with corporate governing structure, ICT policy and standards document to cover ICT operations across the enterprise network;
- Establish internal controls and security for market sensitive data;
- Create special fit-for-purpose server room in a restricted part of the building with security arrangements, centralize server resources across the various sections and improve authentication for users;
- Fully implement AMR as the primary system for collecting grid meter data and feeding the data to the settlement system;
- Install redundant AMR (hub – ACTARIS System) to address risk of unplanned AMR hub outage;
- Create private built-for-purpose web portal for all energy data from the System Operator and all market data supplied to Market Participants;
- Hosted e-discovery services should be procured as part of the hosted email service contract.

Budgets for miscellaneous item in the Office Tools, Furniture & Equipment and Motor Vehicles categories are developed using trending that assumes growth over time with the expansion of the market.

Table 3-1: MO Capital Expenditures 2014-15

Capital Investments	2014	2015	2016	2017	2018	2014-18
In 2013 US$ millions						
Office Tools, Furniture & Equipment	1.5	11.6	0.9	0.5	0.5	15
Motor Vehicles	0.7	0.7	0.7	0.7	0.7	3
Total Investments	2.2	12.3	1.6	1.2	1.2	15
In Nominal NGN millions						
Office Tools, Furniture & Equipment	239	1,928	151	97	101	2,516
Motor Vehicles	111	116	121	127	133	608
Total Investments	350	2,044	272	224	234	3,124

Table 3-2: MO Operating Expenditures 2014-15

Operating Expenses	2014	2015
In Nominal NGN millions		
Payroll	461	593
Repairs & maintenance	21	24
Administration & overheads	315	369
Milestone Deliverables	32	36
Management Fees	29	31
Total operating expenses	858	1,052

Staff Strength

The current MO headcount is 56. The headcount will increase to 79 by end 2014, and to 86 by 2015.

ANNEX 2: TCN Financial Statements 2013-15

1. Income Statements

In Nominal NGN millions	2013 Unaudited	2014 Forecast	2015 Forecast
Energy wheeled (sent out by stations) (GWh)	28,879	31,048	36,654
Transmission losses (%)	12.1%	11.6%	11.0%
Bulk supply to DisCos (GWh)	25,373	27,446	32,622
Average tariff			
NGN/MWh	1,432	2,529	5,148
US$/MWh	9.20	16.09	31.96
Operating revenue			
Wheeling charges	29,742	56,261	137,654
SO & MO administration services	6,022	10,049	19,726
SO Ancillary services	575	3,098	10,567
NERC regulatory charges	894	1,233	2,361
Other operating revenue	757	819	876
Total operating revenue	37,989	71,460	171,184
Operating expenses			
Payroll	16,551	18,369	24,420
Repairs & maintenance	6,108	10,841	25,316
SO Ancillary services	575	3,098	10,567
NERC regulatory charges	894	1,233	2,361
Administration & overheads	3,914	6,497	8,029
Operating expenses before depreciation & provisions	28,042	40,039	70,694
Depreciation	10,886	15,847	24,475
Provisions for bad debts	7,644	29,314	0
Total operating expenses	46,572	85,201	95,169
Operating profit/(loss)	(8,583)	(13,741)	76,015
Non-operating income - net	0	0	0
Net finance charges	40	(395)	(674)
Profit/(loss) before taxation	(8,543)	(14,136)	75,341
Taxation	0	0	0
Profit/(loss) after taxation	(8,543)	(14,136)	75,341
Ratios			
Av. operating profit/(loss) N/MWh	(338)	(501)	2,330
Av. operating profit/(loss) US$/MWh	(2.17)	(3.19)	14.47
Operating margin (%)	-22.6%	-19.2%	44.4%
Return on equity (%)	-2.6%	-2.4%	8.1%

2. Balance Sheets

In Nominal NGN millions	2013 Unaudited	2014 Forecast	2015 Forecast
Fixed & other long-term assets			
Tangible assets at cost/valuation	364,968	882,190	1,306,936
Less: Accumulated depreciation	31,897	47,745	72,220
Net book value of fixed assets	333,070	834,445	1,234,716
Liquidiy facility (AFD)	0	0	2,143
Project funds & advances	55,729	40,154	40,154
Total long-term assets	388,799	874,599	1,277,013
Current assets			
Inventory	12,414	10,801	13,162
Customer accounts receivable	6,647	12,069	25,871
Other debtors & prepayments	327	354	379
Cash at bank and in hand	7,550	457	79,961
Total current assets	26,937	23,680	119,372
Current liabilities (amounts falling due within one year)	0	0	0
Creditors	5,951	4,600	7,740
Bank overdraft	0	5,030	7,625
Debt service due	0	0	1,527
Current Portion of long-term loans	0	2,094	2,530
Total current liabilities	5,951	11,725	19,422
Net current assets/(liabilities)	20,986	11,955	99,950
Total assets less current liabilities	409,785	886,555	1,376,963
Creditors (amounts falling due after more than one year)			
Long-term loans	38,990	70,468	336,983
Less: Current portion	0	2,094	2,530
Long-term portion	38,990	68,374	334,453
Employee benefits scheme	4,136	4,136	4,136
Total creditors (amounts falling due after more than one year)	43,126	72,510	338,589
Net assets employed	366,659	814,045	1,038,374
Capital and reserves			
Capital & reserves	177,490	163,354	238,695
Grants & Government contribution for investments	189,169	650,691	799,679
Shareholders' equity	366,659	814,045	1,038,374
Ratios			
Current ratio (times)	4.5	2.0	6.1
Debt/equity ratio	11%	8%	25%

3. Cash Flows

In Nominal NGN millions	2013 Unaudited	2014 Forecast	2015 Forecast
Net cash inflow/(outflow) from operating activities:			
Operating profit/(loss)	(8,583)	(13,741)	76,015
Depreciation	10,886	15,847	24,475
(Increase)/decrease in stocks	(2,602)	1,613	(2,362)
(Increase)/decrease in debtors	(480)	(5,449)	(13,826)
Increase/(decrease) in creditors	2,759	(1,351)	3,140
Other	112	0	0
Net cash inflow/(outflow) from operating activities	2,092	(3,081)	87,443
Returns from investments and servicing of finance:			
Interest received	40	0	21
Interest paid	0	0	(480)
Net cash outflow for returns on investments & servicing of finance	40	0	(459)
Taxation paid	0	0	0
Investing activities:			
Payments to acquire tangible fixed assets	(16,161)	(205,125)	(418,504)
Project funds & advances	(11,386)	15,575	0
Net cash outflow from investing activities	(27,547)	(189,550)	(418,504)
Net cash inflow/(outflow) before financing	(25,415)	(192,630)	(331,520)
Financing activities:			
Grants & Government contribution for investments	12,020	151,122	148,988
Borrowing	15,575	29,385	262,632
Borrowing repaid	0	0	(1,047)
Liquidiy facility (AFD)	0	0	(2,143)
Net cash inflow from financing activities	27,595	180,507	408,430
Increase/(decrease) in cash and cash equivalents	2,181	(12,124)	76,910
Cash and cash equivalents at beginning of year	5,369	7,550	(4,574)
Cash and cash equivalents at end of year	7,550	(4,574)	72,336
Ratios			
Self-financing ratio (%)	3%	-1%	27%
Debt service cover (times)	0.0	(2.6)	90.7