Generating power and controversy: Understanding Tanzania's independent power projects

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Abstract
Initially conceived of within the broader context of power sector reform in the late 1980s and early 1990s, Independent Power Projects (IPPs) were intended to relieve state utilities of the burden of financing new plants, bring quick, quality power and reduce costs for end-users. Although IPPs have indeed contributed to generation capacity in Tanzania, much of the power that resulted from investments has been supplied neither quickly nor cheaply.

Embarking on power sector reform in the early 1990s, Tanzania made IPPs a pillar of its reform strategy. Presently, Songas and IPTL, the country's two IPPs are helping to reduce load shedding. However, these projects have not been without controversy. One of Tanzania's IPPs was taken to international arbitration over a dispute related to construction costs. The state electric utility, Tanzania Electric Supply Company Limited (TANESCO), currently pays more than 50% of its current revenue towards combined fuel and capacity charges for the IPPs. Capacity charges for the country's two IPPs are equivalent to approximately one percent of GDP. The Government of Tanzania (GoT) is intervening to assist TANESCO with its monthly IPP payments at present. With twenty-year Power Purchase Agreements (PPAs) between IPPs and TANESCO, these costs are expected to continue, albeit with some modifications due to refinancing, fuel conversion and further development of the natural gas market.

This paper provides a detailed summary of how and why IPPs developed in Tanzania as well as their impact to date. Development outcomes, namely the extent to which the host country is benefiting from reliable, affordable power and investment outcomes, the degree to which investors have made favourable returns and been able to expand market share, are analysed in turn.

IPPs offer more than a decade of experiences in private sector investment in developing countries and a detailed understanding of them may be the key to unlocking and sustaining future power investment.

Keywords: Tanzania, independent power projects, power sector reform, power purchase agreements, Tanzania Electric Supply Company Limited

Abbreviations and acronyms

AFUDC	Allowance for Funds Used During Construction
BOT	Build Operate Transfer
BOOT	Build Own Operate Transfer
CDC	Commonwealth Development Corporation
COD	Commercial Operation Date
DEG	German Investment & Development Company
EDF	Electricity de France
EIB	European Investment Bank
EPC	Engineering Procurement and Construction Contract
ESI	Electricity Supply Industry
ESMAP	Energy Sector Management Assistance Program
EWURA	Energy and Water Utilities Regulatory Authority
FMO	Dutch Development Company
HFO	Heavy Fuel Oil

IPTL	Independent Power Tanzania Limited
ICSID	World Bank's International Centre for Settlement of Investment Disputes
IDA	World Bank International Development Association
IFC	International Finance Corporation
IPS	Industrial Promotion Services
MEM	Ministry of Energy and Minerals
Norad	Norwegian Agency for Development Cooperation
OCGT	Open Cycle Gas Turbines
ODA	Official/Overseas Development Assistance
PPA	Power Purchase Agreement
PSRC	Parastatal Sector Reform Commission
SAPP	Southern African Power Pool
Sida	Swedish International Development Cooperation Agency
TANESCO	Tanzania Electricity Supply Company Limited
TDFL	Tanzania Development Finance Company Limited
TPDC	Tanzania Petroleum Development Corporation
Tsh	Tanzania Shilling
USAID	United States Agency for International Development
UGT1	Ubungo Gas Turbine 1 (1-6, I-VI)
VIP	VIP Engineering Limited

1. Introduction

Tanzania is among the African states that has embarked on extensive programs of power sector reforms and Independent Power Project (IPP) development. Unlike many elements of Tanzania's reform plans in the 1990s, such as establishing a regulator, restructuring the sector, and privatising the utility, the introduction of IPPs has already materialized. Tanzania's Electricity Supply Industry (ESI), characterized by persistent state-ownership and control, has been transformed by the addition of two IPPs between 2002 and 2004, from being nearly 90% dependent on hydropower to presently 60% dependent on thermal power. Benefiting from new thermal capacity, Tanzania was among the few East African countries able to avoid substantial load shedding. However, in early 2006, drought conditions eroded Tanzania's hydro capacity beyond what the IPPs could provide, and the country resorted to extensive load shedding in February and March 2006.

Tanzania is a particularly important case for assessing lessons from IPPs for Africa. Notable aspects of Tanzania's IPP program include: IPPs making extensive contributions to the ESI, the GoT's (Government of Tanzania) early efforts to adopt reforms, the major contribution of IPPs to reduce load shedding, the controversial nature of the IPP costs and development process, and the GoT's intervention to assist the Tanzania Electricity Supply Company Limited (TANESCO), the state utility, with its monthly payments. Tanzania's IPP experience also offers the opportunity to examine the role of different stakeholders in the IPP process, including government and private sponsors—both local and foreign—together with the involvement of multilateral lending agencies, such as the World Bank. Additionally, the Ministry of Energy and Minerals (MEM) is currently developing plans to develop future IPPs.[1]

This paper examines the way in which Tanzania's IPPs evolved as well as the impact on stakeholders. Development outcomes, namely the extent to which the host country is benefiting from reliable, affordable power, and investment outcomes, the degree to which investors have made favourable returns and been able to expand market share, are analysed in turn. Based on over two dozen interviews with key stakeholders,[2] this paper also draws on a review of policy documents and reform literature, and an assessment of project outcomes from utility and IPP data. Further resources for the paper include findings from a global study of IPPs[3] and companion IPP case studies in other African countries undertaken by the Management Programme in Infrastructure Reform and Regulation (MIR) at the University of Cape Town.

The authors adopted an inductive research approach, initially conducting a review of reform and project documents, followed by meeting with stakeholders. Conclusions were drawn from the evidence examined and assessment of broad lessons gleaned from Tanzania's IPP experience. The details presented on IPPs and reforms were confirmed across a range of sources. Any errors and omissions are the responsibility of the authors.

2. Power sector reform context

2.1. The start of reforms

The initiation of electricity sector reforms in Tanzania was catalysed by a combination of macro-reform priorities, national energy policy, electricity sector conditions, and international donor priorities. In 1992, the Government expanded macroeconomic reforms started under structural adjustment in the mid-1980s to include sector-focused objectives (Wangwe et al. 1998). Also in 1992, the first National Energy Policy included intentions to involve the private sector in development of the energy sector (MEM, 1992). In the same year, facing a drought-induced electricity crisis and extensive load shedding, the Government lifted the state utility's monopoly on generation to attract private generation and alleviate shortages, which paved the way for the country's two IPPs, discussed in detail in subsequent sections. The reform imperative was reinforced by changes in World Bank lending policy, as the World Bank made electricity sector reforms a condition for electricity sector lending in 1993 (World Bank 1993).

2.2 Early efforts to commercialise and restructure TANESCO, 1992-2001

The driving model of Tanzania's electricity reform was originally aimed at restructuring and unbundling the electricity sector for eventual privatisation.

At the time of initial reforms, TANESCO, the national utility, was already corporatized, with the firm operating under Tanzania's Company Ordinance Act since 1931. During the 1970's to mid-1980's, the national utility performed adequately, yet toward the end of the 1980's utility performance gradually declined (Katyega 2004). Despite its corporatized status, from the early 1990's, the firm recorded poor technical and financial performance, making status quo operation increasingly untenable.

Efforts were made to commercialise and improve TANESCO's operations in the 1990's via the support of the World Bank Power VI project and the World Bank's Energy Sector Management Program (ESMAP) Power Loss Reduction Study and Technical Assistance to TANESCO Project. However, despite these efforts, TANESCO remained in a weak financial position by the late 1990's, and utility performance deteriorated to unprecedented levels.

In 1997, TANESCO was put under the President's Parastatal Sector Reform Commission (PSRC), created in 1992 to oversee the privatisation of state-owned enterprises in industry and manufacturing. Formal intentions to restructure the power sector to achieve unbundling and eventual privatisation were spelled out in a 1997 letter of intent to the World Bank, including restructuring plans to unbundle TANESCO into two generation companies, one transmission company, and two distribution companies. A 1999 Cabinet decision outlined an electric industry policy and restructuring framework to move ahead on restructuring and unbundling in preparation for privatisation. However, no progress was made with unbundling.

2.3 The management contract and future reforms

Seeking more dramatic financial turn-around in preparation for privatisation, the MEM issued a request for proposals for a management contract for TANESCO in 2001, which was won by the South African company, NETGroup Solutions in 2002. Under NETGroup Solutions and with the support of the GoT, TANESCO doubled revenue collection from US$11 to over 22 million per month between May 2002 and May 2004 (Davies 2004; and unpublished TANESCO data). These gains were achieved mainly through enforcing collections and arrears payment, with particular attention focused on the large arrears of public institutions. Enforcement has included high-profile service disconnections and collections from the police, the national post offices, and even the entire island of Zanzibar in addition to private customers.

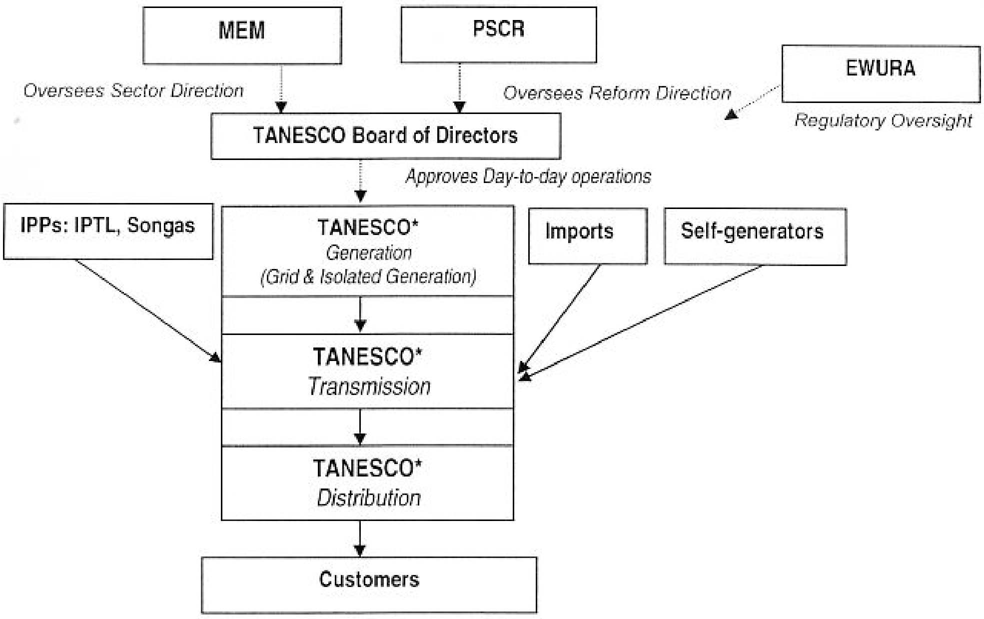
In 2004, the management contract was extended for two years, through to the end of 2006. The extension expanded the mandate of the consultants to include technical turn-around in addition to financial-turn around, specifically including electrification and reliability targets. As of the end of 2005, outcomes of technical turn-around have been limited. Stakeholders cite financial constraints external to the contract – namely poor hydrological conditions, costs of IPP power, and insufficient tariff rates – to be currently limiting TANESCO's ability to make investments to improve electrification or reliability.

The prospect of making up the difference of increasing generation costs via large tariff hikes, raises the question of affordability, namely how high tariffs the economy and society can bear. Residential rates have already tripled in the last three years, and access remains only 10% overall.[4]

As of late 2005, TANESCO was taken off the list of utilities specified for privatisation, under an internal decision of the GoT. This represents a shift in earlier reform goals and timetables. Despecification simplifies oversight and makes it possible for government financed investments – a more flexible arrangement while the GoT considers a range of possible future arrangements for TANESCO (including commercialisation, concession, privatisation, leasing). Presently the MEM is pursuing an incremental restructuring plan for TANESCO, called internal ring-fencing, which separates utility operations into separate business areas in the aim of efficiency gains, while maintaining state-ownership and a single institutional structure. For the time being more elaborate privatisation and unbundling options seem unlikely.

2.4 Structure of the sector

The de factor oversight in the sector has been via the PSRC and the MEM, as illustrated in Figure 1. Although legislation was passed to establish the Energy and Water Utilities Regulatory Authority (EWURA) in 2001, EWURA only became operational in 2006. The PSRC still oversees TANESCO's reform mandate. The MEM oversees the sector direction. The TANESCO Board of Directors is appointed by the MEM and approves the day to day operations of TANESCO, under the management contract with NETGroup Solutions. The over-



*Note: * TANESCO is currently an under performance-based management contract by NETGroup Solutions of South Africa through December 2006.*

Figure 1: Structure and oversight of Tanzania's electricity supply industry

sight of the sector is changing with the de-specification of TANESCO for privatisation, the development of an electricity regulator, and the nearing completion of the NETGroup Solutions contract extension in December 2006. With de-specification, the PSRC will no longer have a direct oversight role over the utility.

3. Tanzania's two main IPPs: IPTL and Songas

Tanzania developed two main IPPs over the last decade,[5] depicted in Tables 1 and 2. Together, they contribute approximately 300 megawatts (MW), or about one third of the country's present generation capacity of 900 MW. In terms of energy sold, Tanzania's IPPs currently contribute over half of electricity generation and represent the main sources of thermal (non-hydro) capacity in the country.

Independent Power Tanzania Limited (IPTL) was the first IPP to begin to sell electricity to the national electric utility. The 100 MW diesel plant consists of ten medium-speed units of ten megawatts each, which presently run on imported Heavy Fuel Oil (HFO). Eventual conversion to domestic natural gas has been intended for IPTL since its original Power Purchase Agreement (PPA) and is presently expected in the near-term.

Songas, Tanzania's second IPP, commenced operations in July 2004. The 190 MW natural gas-fired plant consists of six open-cycle gas turbines (OCGT), which are run on natural gas sourced from the domestic off-shore Songo-Songo gas field (four of the turbines were pre-existing and converted to

Table 1: Technical specifications for Tanzania's IPPs

Projects	*Size (MW)*	*Technology/ Fuel*	*Contract type*	*Contract Years*	*Capacity utilization target*	*Time from tender to operation*
IPTL	100	Diesel generator/ HFO	Build Own Operate (BOO)	20	85%	1994– 2002
Songas	190	OCGT/ Natural gas	BOO	20	91%	1993 – 2004

Note: Songas plant size indicated here represents current capacity, which has evolved extensively from project inception; important to note is that the World Bank credit for Songo-Songo Gas Development and Power Generation Project was used towards the first 115 MW at Ubungo, not the addition of 75 MW, which was financed entirely by the private sector.

Table 2: Financial specifications for Tanzania's IPPs (in US$ million)
Source: Complied by authors, based on World Bank PPI Database, MEM and Songas data and interviews

Projects	*Project cost*	*Total equity (%)*	*Total debt (%)*	*Local equity*	*Local debt*	*Int'l private debt*	*Multil- and bilateral financing*
IPTL	$ 127.2	$38.16 (30%)	$89.04 (70%)	US$1 land lease + in kind (PPA & guarantee, 30%)	-	$89.04	-
Songas without expansion (115 MW)	$266	$60 (30%)	$206 (70%)	$4 (TDFL) $4 (in kind by TANESCO & TPDC)	-	-	$206
Songas expansion (75 MW)	$50	$50 (100%)	-	-	-	-	-

Note: Tanzania Development Finance Company Limited (TDFL); Tanzania Petroleum Development Corporation (TPDC). Songas project costs include refurbishment of gas wells, a new gas processing facility, pipeline construction and fuel conversion of the existing power station (Ubungo), in total amounting to US$266 million, and an additional US$50 million for expansion in terms of two additional turbines (total 75 MW) and related infrastructure. The expansion was financed entirely by equity (although TANESCO is currently pursuing refinancing of the Songas expansion for a split of 75:25 debt/equity, which would reduce capacity charges). A rough estimate for the electricity generation component would be 40% of project costs or US$130 million, based on US$35 million for refurbishment and fuel conversion of existing turbines, US$45 million assumed loans on existing turbines, and US$50 million for expansion. It should be noted, as will be described in detail in the text, that there was considerable evolution in terms of the planned capacity for the plant, from 60 MW to the current 190 MW. A detailed breakdown of finances for both IPTL and Songas is presented in Appendix A.

run on natural gas). The IPP is part of a larger gas project, which included: refurbishment and development of offshore gas wells; installation of a gas processing facility; construction of a 232 kilometre (km) pipeline to Dar es Salaam; conversion of an existing 115 MW power station (Ubungo) from jet fuel to natural gas, consisting of four turbines, as mentioned above; the provision of 75 MW additional capacity at the Ubungo station; the supply of gas for the Twiga cement plant at Wazo Hill; and the development of a larger commercial market for gas.[6] The Songas project benefited from loans from the World Bank, the International Development Association (IDA), the European Investment Bank (EIB), and Swedish International Development Cooperation Agency (Sida) and involved numerous private sector companies and more than 20 contracts.

4. Summary of IPP history

The development of the plants, which is not treated in depth in this paper,[7] spans a decade. In part due to the considerable time involved and in part due to associated controversy, the history of the development of Songas and IPTL is notably complex. For the purpose of this paper, it is critical to understand that Songas preceded IPTL in the planning process. With delays in the Songas project and mounting power outages, however, additional proposals, including that of IPTL were considered. Recognized as contributing to South-South collaboration, IPTL emerged as an independently negotiated IPP among Malaysian investors, VIP, a local Tanzanian firm, and the GoT. The plant would be IPTL financed largely by two Malaysian banks, which were given a guarantee by the Malaysian government that their loans would be secure.

Bribery has been alleged, but not proven in court, as motivating the signing of the IPTL deal, which in turn prompted a halt to the Songas project. The World Bank, among the largest lenders to the sector as well as to Songas specifically, was instrumental in postponing Songas due to the fact that IPTL made Songas redundant; Tanzania could not absorb the capacity from both plants (at the time). Songas would only be recommenced in 2001 after a lengthy arbitration process of three years, a reduction in the IPTL capacity charge, demand for both plants had been ascertained and the allegations of corruption within the sector had been cleared.

During the arbitration process, Songas' Allowance for Funds Used During Construction (AFUDC), namely the compounding interest rate on equity, which GoT and sponsors agreed to in 1995 to help jump-start the project, ballooned to over US$100 million. Other critical developments during this period include equity turnover in Songas, with the major holding of AES and smaller shares by IFC and German Investment & Development Company (DEG) bought by Globeleq[8] and the Dutch Development (FMO). Although initially redundant, by the time Songas finally came online in 2004, power from both plants, although costly, would be absorbed and the need for additional capacity would be tabled.

5. Description of IPP operations and costs

Although Tanzania's IPPs were considerably delayed, since coming on line starting in 2002, the plants have brought about a transformation of the country's ESI—from nearly 100% hydro dependent to thermal plants making up more than 50% of generation.

5.1 Generation and capacity utilization

During a period of drought, starting in 2003, the country turned extensively to power from IPTL, as shown in Figure 2. Subsequently, Songas was integrated into the ESI, albeit later than initially expected, for drought-relief. As noted in the Introduction, the thermal power from IPPs helped the country to avoid serious load shedding between 2002 and the end of 2005, which has saved it around US$1.00 for every kilowatt hour (kWh) of outage averted (or about 5-10 times the cost of generating electricity) (ESMAP 1998).

With increasing pressures due to drought combined with growing demand, the IPP plants have been run at near capacity, since 2003, contrary to initial concerns about the country's ability to absorb the power.

Several points are noteworthy in this context. Firstly, delivery of Songo Songo gas was delayed, which, due to an acute power shortage necessitated emergency generation, namely running existing Ubungo turbines on imported jet fuel as well as additional usage of IPTL. Secondly, Songas was not at full availability in its first year of operation, which also necessitated additional use of IPTL.

Explanations for Songas' delays and subsequent shortfall in capacity have been attributed to failure of a sub-contractor working on the gas infrastructure to deliver on time, expansion work and technical failure of existing turbines. The plant was offline in January 2005 to make connection for the expansion project. Availability suffered again in May-June 2005 due to failure of turbine three. Although Songas was required to pay penalties for these missteps, according to sources within TANESCO and Songas, penalties do not match the additional costs incurred by the utility during the period, which amounted to US$43 million and was financed through an emergency World Bank loan.

Finally, the extent to which the capacity factor, depicted in Figure 3, alters the per kilowatt hour charge of each of the plants is also noteworthy. For instance, at a capacity factor of 1%, at which IPTL was run initially in 2002, the country saw charges of US$4.80/kWh. Approaching nearly 100% capacity use, IPTL charges fall to US$0.097 per kWh. At full capacity, however, IPTL charges are still nearly double those of Songas, despite the fact that the Songas capacity charge is comprehensive of the gas infrastructure.

5.2 Fuel bills, deals and conversion

While the capacity factor goes a long way in explaining the different prices at the end of the spectrum, especially for IPTL, there is a critical difference in per kWh charges (and total monthly charges) that is explained by the difference in fuel on which IPTL and Songas are operating. Songas uses domestic natural gas, whereas IPTL relies on imported diesel fuel.

The gas price for Songas for turbines I-V and for the Twiga cement plant, which was developed as

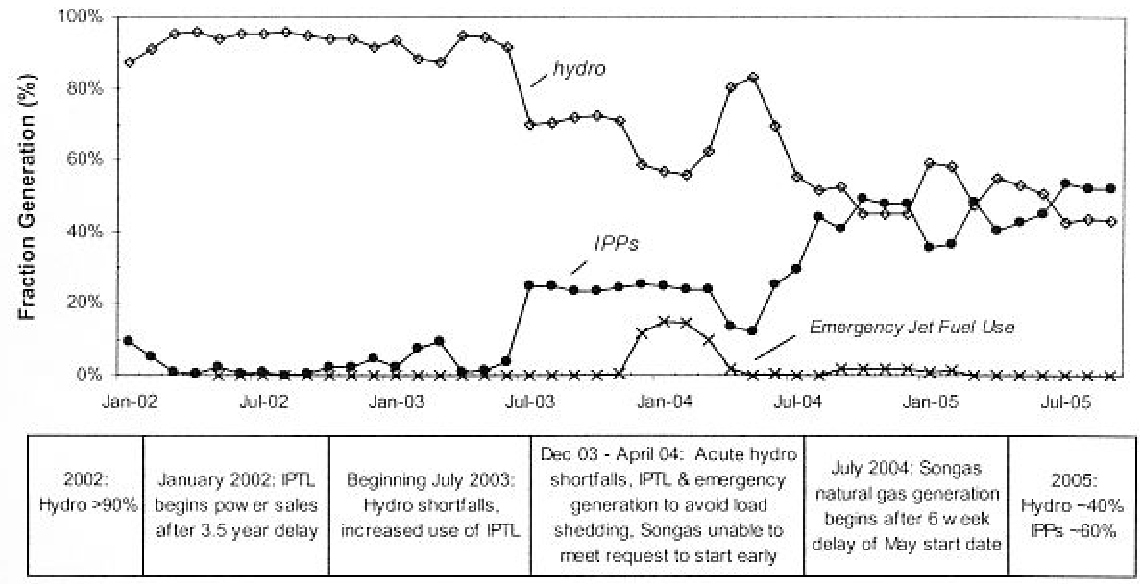
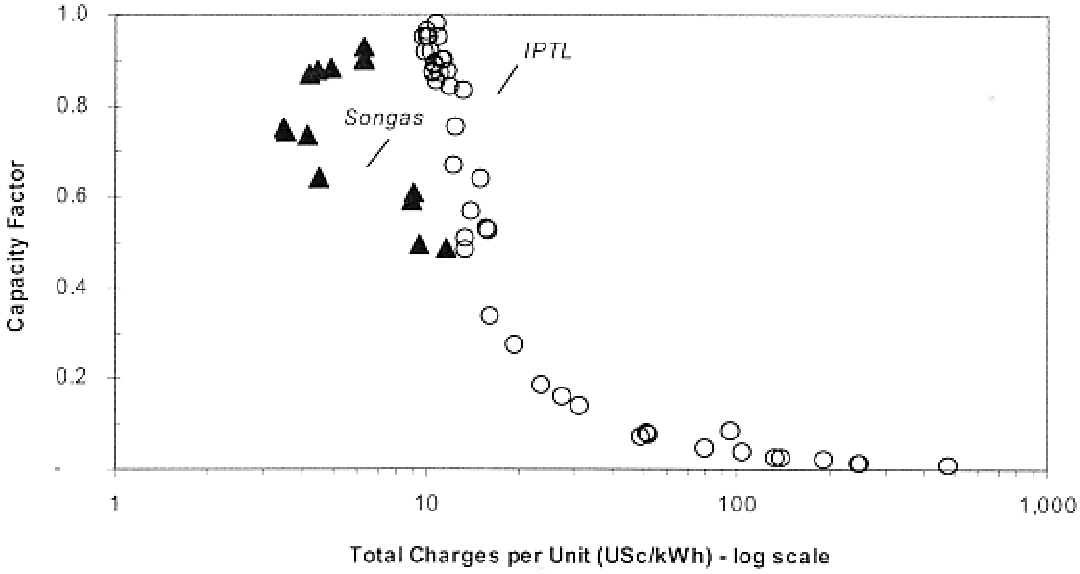


Figure 2: Composition of electricity generation, January 2002 – September 2005



Note: Total charges per unit include energy and capacity charges normalized to generation, and represent monthly averages. IPTL data points include Jan 2002-Sept 2005 (n=43 months); Songas data points include July 2004-Sept 2005 (n=13 months). Unit charges are VAT exclusive.

Figure 3: IPP total charges per unit at different levels of plant use, based on monthly data, Jan 2002 – Sept 2005

part of the Songo Songo gas-to-electricity project, is set at US$0.52/Gigajoule (GJ), indexed to United States Consumer Price Index (US CPI) over the course of the 20 year PPA. The special price of US$0.52 GJ only pertains to the 'protected gas' that has been earmarked for Ubungo turbines I-V and the cement factory.[9] All additional gas that is sold from Songo Songo is priced at a maximum of 75% the buyer's liquid fuel equivalent. Presently TANESCO is negotiating long term gas contracts at between approximately US$2.00 and US$2.40 per GJ, as depicted in Table 3.

Although gas sales with third parties have developed (seven companies as of 2005, indicated in Section 2), they are a fraction of total production; Songas and therefore TANESCO (since fuel is a pass-through) is the primary taker, and therefore is in essence the 'market maker'. Songas's fuel price was conceived of as part of the initial project concept to offset the capacity charges so that the utility would not shoulder the full weight of developing the country's gas infrastructure.

Although not benefiting from special 'protected gas', IPTL was, from project inception, slated to be converted to run on natural gas and source its fuel from the 'additional gas' reserves of Songo Songo. The project was therefore to benefit from an estimated minimum fuel cost savings of 25% (given the additional gas price set at a maximum of 75% the liquid fuel equivalent). This plan was reconfirmed in

Table 3: Songo Songo gas reserves pricing and usage

Source: Compiled by authors based on data provided by East Coast Energy and Tanzania Petroleum Development Corporation, November 2005

Characterization	*Price*	*Notes*
I. Protected Gas	US$0.52/GJ	Allocated for Songas (turbines I-V = 150 MW) plus cement factory for 20 year PPA
II. Additional Gas	Maximum 75% of liquid fuel equivalent	All non-protected gas, includes both reserve gas described below and gas currently used for Ubungo VI (below), IPTL fuel would come from 'additional gas'
i) Reserve Gas	Maximum 75% of liquidfuel equivalent	100 Bcf of gas set aside for government to determine use within 5 years of transfer date (July 2004)
ii) Ubungo turbine VI	US$2.20/GJ	A temporary agreement for Ubungo turbine VI, presently negotiating price

the IPTL arbitration when US$11.6 million was tagged as an estimate to be paid by TANESCO for converting IPTL (currently estimated at US$20 million). While the savings is not equivalent to Songas, it would amount to a reduction of approximately US$1 million per month (given a current average monthly fuel charge of about US$3.6 million).10

Songo Songo gas was available starting July 2004. However, IPTL has still not been converted. It is expected that conversion will commence in August 2006 and be implemented in stages, completed by March/April 2007. Stakeholders attribute conversion delays to a host of factors: probability and availability of fuel reserves; technological conversion challenges; securing financing; resistance from lenders; fuel pricing formula; and debt and equity renegotiation/disputes.[11] Of these six factors contributing to delays, among the most common cited by stakeholders is that concerning conversion of the technology itself. The engines need to be converted, but Wartsila SWD 18 V 38 diesel engines have never run on natural gas. Thus Warsila, which is also the operator of IPTL, must first conduct a series of tests. Although according to one stakeholder close to the project, 'this is not rocket science' a test-bench must be booked and time allotted to carry out the work.

5.3 Monthly charges to TANESCO

Actual monthly charges to TANESCO for operating the two IPPs (inclusive of both energy and capacity payments) during 2005 have amounted to an average of US$13 million per month, or well over 50% of TANESCO's monthly revenue, illustrated in Table 4. Although capacity factors matter in terms of the price per kilowatt hour, they have no bearing on the total capacity charge, which is a fixed monthly charge to the utility to finance the capital cost of the project, unlike the energy charge which varies with operation. For IPTL, these capacity charges were negotiated on a straight-line basis for the 20-year duration of the PPA, which means provided there are no changes to the project ownership or debt, the utility will pay US$2.6 million monthly, adjusted

Table 4: IPP monthly charges and generation

Source: Calculated by authors from unpublished TANESCO data, 2005

	2005 Average	*Whole period Average*	*Whole period Range*
IPTL			
Capacity Charge (million USD/mo)	2.7	2.5	2.3 – 2.8
Energy Charge (million USD/mo)	3.6	2.5	0.03 – 5.0
VAT (20%) (million USD/mo)	1.6	1.3	0.05 – 1.9
Total IPTL Charges (million USD/mo)	$7.9	$6.3	$2.9 – 9.8
Total IPTL Generation (GWh/mo)	50.7	38.5	0.5 – 73
Songas			
Capacity Charge (million USD/mo)	3.2	3.5	2.2 – 4.0
Energy Charge (million USD/mo)	1.0	0.9	0.2 – 1.5
VAT (20%) (million USD/mo)	0.7	0.8	1.0 – 1.1
Total Songas Charges (million USD/mo)	$4.9	$5.2	$3.9 – 6.3
Total Songas Generation (GWh/mo)	86.1	79.1	19 – 120
IPP Charges (million USD/mo)	$12.8	$ 7.9	$2.3-14.8
TANESCO Revenue (million USD/mo)	$18.6	$15.8	$12.2 – 22.0
IPP Charges vs. TANESCO Revenue (%)	69%	50%	16-92%
IPP Generation (GWh/mo)	137	67	0.54 – 165
Total Generation (GWh/mo)	301	272	233 – 308
IPP vs. Total Generation (%)	45%	24%	0.2-54%

Note: Average IPP monthly charges for 2005 are based on monthly data available for the period Jan to Sept 2005. Average values for the whole period for each respective IPP include: IPTL Jan 02-Sept 05, for Songas July 04-Sept 05. Also note that total IPP charges and total IPP generation during whole period do not equal the sum of individual IPTL and Songas values. Total charges span the whole period from 2002 to Sept, 2005. However, Songas only came on line in July 2004. Thus for many months only IPTL was running, and average values and ranges do not correspond. Full Songas charges would amount to US$ 5.8 million per month if full debt was being paid.

for inflation, going forward. For Songas, the situation is different, as the capacity charge *declines* on a straight-line basis to zero over the life of the project, with the loan repaid by year 18.

A number of issues are worth reiterating in this context. Firstly, the fluctuations in the capacity charge depicted in Table 4 relate to: annual inflation adjustments for both IPTL and Songas; change in Songas debt payments (discussed below): increased Songas capacity, with turbines V and VI coming online mid-February and end-May 2005, respectively. Secondly, Songas's capacity charges are inclusive of the entire gas infrastructure and should not be mistaken for the price of electricity generated from Ubungo alone. Thirdly, as also discussed above, the most significant monthly charge for 2005 has been the variable energy charge for IPTL, a cost, which is expected to reduce by a minimum of 25% after the plant is converted to run on natural gas.

A final issue relevant to the present capacity charges is that TANESCO has not been paying the subordinated debt portion of the Songas capacity charge since May 2005.[12] Full charges would reflect the 7.1% interest rate and amount to approximately US$5.8 million per month (plus US$1 million VAT), with US$4.2 million for turbines I through IV and an additional US$1.6 million for turbines V and VI.

The current non-payment of the subordinated debt was provided for in the subsidiary Loan Agreement dated October 11, 2001. Due to the fact that GoT borrowed funds from IDA and on-lent to Songas (at a premium), if TANESCO fails to pay Songas the amount equivalent to the principle and interest, Songas is relieved and forgiven up to that amount, while TANESCO is treated as a borrower at more stringent interest but relieved until it is able to pay. Since TANESCO is wholly-owned by the state, it is up to TANESCO to make a case either to pay or swap with other obligations of the State. The existing arrangement may continue until such time when the Government declares the utility bankrupt or TANESCO becomes liquid and pays. This arrangement has helped the utility to reduce its present financial liabilities to Songas to almost half.

Although there has yet to be an impact on either plant operations or charges, equally noteworthy in this context are the idiosyncrasies and conflicts related to IPTL's debt structure, which evolved after Commercial Operation Date (COD). In February 2002, only one month after IPTL commenced commercial operations, local partner VIP petitioned the High Court of Tanzania to wind up the project company. Reasons provided by VIP were: oppression by the majority shareholder (namely that Mechmar refused to involve the VIP nominee director of IPTL in corporate decisions); fraud by Mechmar in inflating the IPTL capital cost; and failure by Mechmar to pay its equity contribution (i.e. the project was 100% debt financed). IPTL management has denied all claims.[13] There has been no resolution of this conflict. In the meantime, however, IPTL's debt, which was non-performing, was first purchased by Danaharta, a Malaysian entity that bought up many non-performing loans after the East Asian financial crisis, and then resold to Standard Chartered for US$74 million in November 2005. VIP has subsequently contested the sale to Standard Chartered on the basis that the very loans that were resold are under dispute. Presently there is discussion of the GoT buying the debt from Standard Chartered for between approximately US$70 and 80 million, although VIP asserts that, according to the amortization schedule in the arbitration award, the value of the debt should be no more than US$40 million. Should any sale be finalized with GoT, the project may see a reduction in capacity charges.

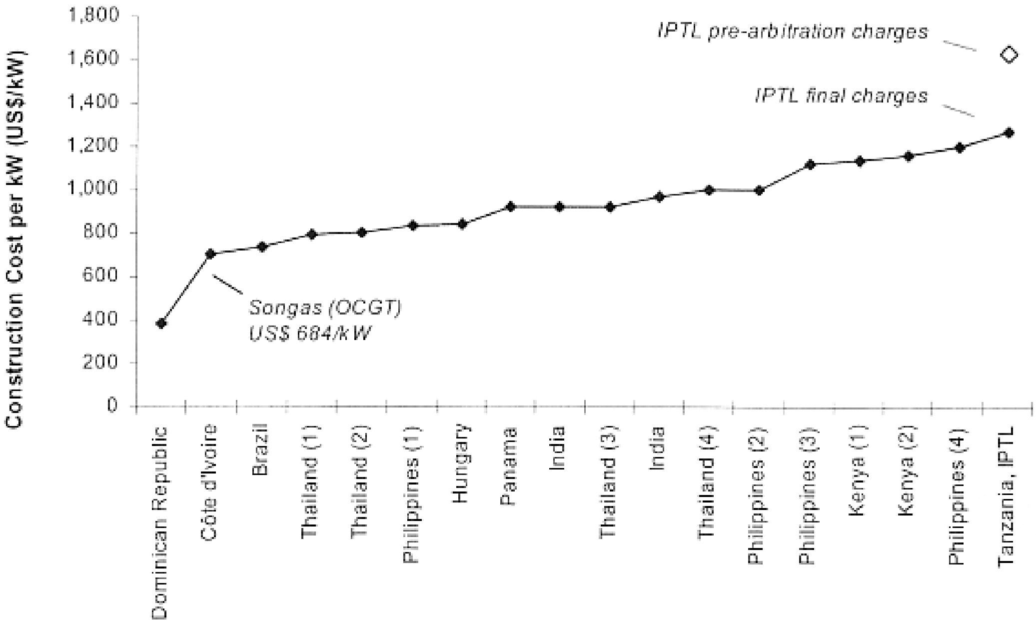
5.4 Benchmarking costs

It has been established that IPTL is presently more expensive than Songas, but are the costs reasonable? Based on construction costs per kilowatt, IPTL appears to have the highest such costs within a sample of similar size/technology IPPs in developing countries. Kenya's Tsavo and Iberafrica plants are, however, within close proximity, indicating that costs may be generally inflated for the East Africa region. Although Songas employs a different technology, namely Open Cycle Gas Turbines (OCGT),[14] it is worth noting that isolating project costs related only to the plant, the per kilowatt construction costs are approximately US$684 or about half those of IPTL (in Figure 4).

Given Songas's lower variable cost, the plant is dispatched before ITPL (following basic merit order dispatch protocol). Thus, Songas is contributing more in terms of total generation. A notable point in this context is that although IPTL constitutes only 37% of the total IPP generation for 2005, its costs account for 62% of the total (IPP generation).

An analysis of the per kilowatt charge of the two projects confirms the contrast in costs. Although IPTL has been running at a slightly higher capacity factor (70% in 2005)—the total kWh charge for the plant was still more than two and a half times that of Songas, as depicted in Table 5.

In sum, IPTL costs do appear to be higher both than the international norm and than its IPP counterpart, Songas. There are, however, several costs to Songas that are not presently reflected in the capacity charge, namely the AFUDC, the full cost of debt, the escrow facility,[15] and the sunk cost of the original drilling of the wells in the 1970s. An assessment of Songas's total charge per unit including these elements would be measurably higher.



Note: Small diesel in Figure 4 includes plants in developing countries with capacity less than 110 MW. It has been brought to the authors' attention that Kenya's first plant does not meet technology specifications and therefore should be omitted from this analysis.

Figure 4: IPTL construction costs versus small diesel IPPs in developing countries
Source: Calculated by authors based on data from (World Bank, 2004; MIR, 2005)

6. Analysis of outcomes

6.1 Overview of development and investment outcomes

Our final analysis weighs *development outcomes* (the extent to which reliable power is supplied at reasonable rates) on the one hand with *investment outcomes* (whether returns sufficiently reward risk and the extent to which investment opportunities may grow) on the other.[16] This paper asserts that these two outcomes must strike a broad balance for projects to be sustainable, that is, for existing contracts to hold and future investments to be made in the sector.

The development outcome for Tanzania has been mixed. The country has been able to expand its generation capacity and did not resort to serious

Table 5: IPP Total charges per unit over lifetime of projects to date, January 2002 to September 2005
Source: Calculated by authors from unpublished TANESCO data, 2005

	2005 Average	*Whole period Average*	*Whole period Range*
IPTL			
Capacity factor	0.70	0.67	0.01 – 0.98
Energy charge per unit (USc/kWh)	7.4	6.8	3.9 – 54
Total charge per unit (USc/kWh)	13	14	9.7 – 483
Songas			
Capacity factor	0.73	0.79	0.49 – 0.93
Energy charge per unit (USc/kWh)	1.2	1.1	0.4 – 2.0
Total charge per unit (USc/kWh)	4.9	5.5	3.5 – 12

Note: IPP monthly average capacity factors are calculated from name plate capacity and monthly electricity generation, based on 100 MW capacity for IPTL and incremental increases in capacity with development of Songas: 78 MW (Aug-Sept, 2005), 115 MW (Oct 1, 2004-March 9, 2005), 151 MW (March 10, 2005-June 7, 2005)), and 190 MW (beginning June 8, 2005). Average charges per unit include energy and capacity charges normalized to generation over respective period, VAT exclusive. For IPTL the whole period includes Jan 02-Sept 05, for Songas July 04-Sept 05.

load-shedding between 2002 and 2005. Tanzania also has succeeded in commercialising its natural gas, which has helped reduce the fuel bill for the state utility and numerous other small industries (previously reliant on petroleum imports) as well as alleviate the pressures related to securing quality fuel in a timely manner from abroad. GoT may claim a payback period of less than half the time originally estimated on turbines I-IV of the Songas project (or three years instead of six), due to the increase in JET A-1 fuel prices.[17]

Despite these developmental gains, power in the case of IPTL is, as has been shown in the previous section, proving to be more expensive than the international norm (even post-arbitration). Furthermore, the IPTL arbitration was particularly costly to Tanzania, both in terms of direct and indirect costs of arbitration, and eroding credibility of the project in the eyes of many stakeholders. Songas, while less costly than IPTL, did incur significant costs to the country in the form of the AFUDC and the escrow account. The extent to which IPTL and IPTL-related events inflated Songas costs (particularly the AFUDC being 75% more expensive than expected) should not be overlooked.

With regard to the investment outcome, it too has been mixed. Parties have secured a return on equity (ROE) of 22%, but there has been significant equity turnover, and Globeleq, which has its origins in development, is the third lead shareholder on the Songas project, after previous ones lost interest due in part to project delays. The present majority shareholder in IPTL, Mechmar, has been trying to sell the asset for several years and the minority shareholder issued a winding up petition to terminate the company three years ago. TANESCO has been unable to make its full debt payments (to Songas and hence to the GoT), and IPTL's loans were declared non-performing, then bought by Danaharta, an initiative of the Malaysian government, and most recently by Standard Chartered. Although there is talk of future IPPs, no framework for this next spate of investments has been made public. The emergency power that will plug the current power deficit will be financed through state and concessionary funds.

6.2 Factors contributing to outcomes

A suite of factors that explain development and investment outcomes has emerged from the global IPP experience, which have been grouped in terms of their applicability *across* projects (country-level factors) and *to* specific projects (project-level factors). Macroeconomic shocks, the state of the investment climate and the electricity sector appear to be relevant across projects in terms of impacting development and investment outcomes. Project-specific factors of interest are: the composition of project partners, project finance, the PPA, the fuel type and agreements, political and public perception and lastly, project management.

6.2.1 The investment climate: risk perceptions

Although of particular significance across the global IPP study, macroeconomic shock did not play an important role in determining IPP outcomes in Tanzania. Throughout South East Asia, Latin America and in Egypt, major currency devaluations have raised the local cost of projects as PPAs have mostly been denominated in US dollars. Instead, in Tanzania, there is evidence of creeping devaluation throughout the course of the 1990s, followed by a relatively stable currency environment in the period since the IPPs have come online. Thus there has been little to no perceived impact to date, however, with PPAs of 20 year duration, denominated in US dollars, there is always a risk of future impact, which may be exacerbated by the rising price of fuel imports (so long as IPTL relies on HFO). In contrast, the investment climate and the state of the electricity sector have figured much more prominently in shaping outcomes and will therefore be treated in detail here.

The first initiative to develop the Songo Songo gas field collapsed in the 1980s largely due to the poor investment climate. At the time of the inception of the IPP plans in the early-mid 1990s, little had improved in terms of the investment conditions. It is arguable that conditions had even worsened, with an all time high inflation level of between 30-35% reported in the mid-1990s and no foreign commercial lenders willing to lend to the sector.

While there were several impediments to the initial bid for Songas (size of plant and short bid time), the investment climate features prominently in why more investors did not come to the table. With the risk of expropriation still perceived, investors took little interest in the Songas bid, with only two of the 16 firms invited submitting bids.[18] It should also be noted that the mere fact that there were no previous such investments exacerbated the perception of risk.

Both IPTL and Songas eventually obtained debt at interest rates of less than 10% (below commercial rates, available in the mid-teens), but the debt was not easy to come by, which may also be linked to the poorly perceived investment climate in Tanzania. In the case of IPTL, eventually the Government of Malaysia intervened to convince two Malaysian banks that their loans would be secure, which amounted to an informal guarantee on the part of the Malaysian government.

In the case of the Songo Songo gas-to-electricity project, in a departure from most project-financed IPP deals globally, the GoT obtained concessionary loans, which it then on-lent to the project sponsor. Although less costly than commercial debt (which again was not available to the sector at the time), these loans required substantial time and conditions (with the World Bank mandating that any future power investments in excess of US$5 million first receive World Bank approval—a more stringent condition than that laid out in the Power VI plan, which only required notification not approval).

Although both IPTL and Songas were able to obtain debt at interest rates of less than 10%, the two project companies required a ROE of 22%, a further indication of the riskiness of the investments and the general climate. According to sponsors, this was comparable to the ROE of projects with similar risk profiles within the region and adequately reflected the risk inherent in the Tanzanian ESI, namely that TANESCO, the off-taker, had no experience in paying IPP capacity charges and was financially feeble at the time.

It is arguable, however, that much of the risk was mitigated by additional facilities negotiated by the projects, which have been used extensively for infrastructure projects globally. Both projects negotiated liquidity-type facilities, (although IPTL's is referred to as an escrow account and has yet to materialize). In addition, IPTL obtained a sovereign guarantee equivalent to the value of the PPA. Songas received no outright guarantee, but it did convince the GoT to establish an escrow facility and provide a rate of 22% on AFUDC compounding annually.

Although the investment climate contributed significantly to outcomes, one cannot attribute to it all of the project ills or benefits. There was after all no independent regulator to review PPA contracts. Furthermore, other factors such as actual project plans and execution have contributed significantly to outcomes.

6.2.2 The electricity sector: drought, doubt and reform

The management of the electricity sector, which was widely affected by drought and the intervention of other ministries, played an equally if not more important role in determining project outcomes than those previously discussed. The primary issue of relevance in this context is the planning and execution of the Power System Master Plan, which initially included specifications for Songas, but not for IPTL.

Throughout the early and mid-1990s, Tanzania experienced severe drought conditions and power shortages. It was in this emergency context that four turbines were installed at Ubungo prior to completion of the Songas deal. It was also in this context that IPTL first bid to build fast track power in Tanzania. According to several stakeholders in the MEM, they were roughly operating within the Master Plan but on a six month time frame with the intent of solving the drought induced shortages as expeditiously as possible. But six months came and went with Songas, and sponsors and other key stakeholders did not see the project materializing.

With deadlines passing and power cuts persisting, it is alleged that other ministries, affected by the power cuts, started second guessing the six month fix. There was a general sense that TANESCO and MEM, following the World Bank procurement procedures and relying on concessionary loans, were not able to deliver projects on time to address the shortages. The cost of unserved electricity to the economy was high and therefore Tanzania paid dearly for no power. Thus the backdrop of the IPTL agreement appears to have been a failure to deliver on the Master Plan and hefty associated costs for many Tanzanians facing loss of services, TANESCO facing loss in revenue, and the Tanzanian economy facing loss of productivity, together with a clear interest in collaborating with Malaysian investors in the context of South-South partnerships. Ultimately the sector suffered from poor planning and execution, which interfered with the one plant solution and the original Master Plan.

It is difficult to fully assess the impacts of the overall ESI reform process on the IPPs. The IPP deals were concluded, despite the postponement of the unbundling of TANESCO, its privatisation, and the establishment of the regulatory agency. The private management contract for TANESCO has improved its financial position, and it is in a better position to service its PPAs – however, the GoT has shown that it is prepared to step-in and assist TANESCO when necessary. Presently GoT shoulders 30% of the PPA charges.[19]

In reflecting on reforms, stakeholders provide a range of comments. Some assert that full implementation of reforms would have radically changed that status quo. The country could have had cheaper power, including possibly sourced from the Southern African Power Pool, and may not be facing the current emergency situation. Others argue that reforms may not have altered the present condition of the ESI. The drought and political interference could have easily sabotaged any Master Plan and attempts to screen projects by an independent regulator.

Stakeholders insist further tariff increases are necessary to deal with the increasing costs of generation with reliance on more costly IPPs. However, these increases have a high cost to the economy and society, as Tanzania is trying to make industrial tariffs competitive with neighbouring countries and residential customers have already experienced a tripling of residential bills in the last three years. The need for further tariff increases – effectively a result of IPTL's high construction charges, Songas' high interest charges, delays in conversion of IPTL, and ostensibly high private sector returns – flies in the face of promises to the public that tariffs would decrease rather than increase with reforms. Notably, electrification rates have not increased, as revenue gains are going to paying for more costly generation rather than investments in expanding services. The IPPs are filling a critical gap in supplying much needed power. However, combined IPP charges leave little for other improvements, despite the utility's doubling of revenues.

6.2.3 Making and breaking the Songas project

Although both the investment climate and the state and management of the electricity sector go a long way in explaining development and investment outcomes, a series of project-specific factors provide even further clarity as to how and why projects have faired for the host country and investors. In terms of Songas, five main issues standout: the characteristics and the conditions of the project partners, the idiosyncrasy of the project financing, the PPA's AFUDC, the benefits of the gas agreement and the equity turnover.

World Bank put Songas on hold in 1997 after it became clear that IPTL was coming online. The World Bank only gave the go ahead for the Songas project to recommence in 2000-01, following the arbitration process (which according to some stakeholders served to cleanse IPTL and the sector of alleged corruption); it had been proven that Tanzania's demand growth could absorb capacity from both plants; and following justifications by MEM.[20] Although the root cause was the IPTL dispute, during the time that Songas was postponed, the AFUDC accumulated, reaching over US$100 million by 2003. Furthermore, all procurement processes were aborted and then restarted. While the project may not have happened without World Bank support, the presence of the Bank led to a very distinct set of outcomes.

The GoT, Songas's largest lender (on-lending the World Bank and EIB funds to the project company) has supported the project extensively. The financing agreement was that the World Bank would on-lend to the Government of Tanzania and the Government would in turn on-lend to the project at a higher rate, in an attempt to move TANESCO toward commercialisation. With TANESCO facing financial constraints, particularly since May 2005, the terms of finance have been readjusted, as per the 2001 subsidiary loan agreement, with Government accepting a postponement of interest and principal. This agreement is presently reducing TANESCO's capacity charges to Songas by almost half. It is an arrangement that could not have happened under a commercial bank agreement, which would have most likely resulted in project default (then again, no commercial banks were available to lend to the project at the time of financing).

While the terms and conditions of the concessionary loan are currently making Songas less expensive, the buy-down of the AFUDC on the part of the GoT has also contributed to lower costs for the utility. Without the buy-down, TANESCO would currently be facing charges of US$6 million per month for turbines I-IV.

A final factor in 'making' the Songas project is the equity turnover and the emergence of Globeleq as lead shareholder. Globeleq's appetite for risk, which may be largely a function of its lower cost of capital due to its shareholder structure (see footnote 8), combined with its knowledge and experience in Tanzania has meant that the project materialized even after TransCanada and AES grew sour on the investment.[21]

6.2.4 Disputing and depending on IPTL

IPTL reveals an equal range of factors that have affected outcomes. Project partners have also made a significant imprint on the project as has the project finance and the fuel type and agreement. Among the most visible factors related to IPTL, however, has been the allegation of corruption. According to numerous stakeholders, it was bribery that helped seal the deal between IPTL and the GoT, causing inflated project costs, postponement of Songas, and ultimately arbitration and subsequent delay of IPTL. An attempt by TANESCO to cancel the plant based on corruption, however, failed, and the utility did not pursue further investigation, as offered by the International Center for Settlement of Investment Disputes (ICSID). Similarly, an investigation into corruption led by GoT was completed, but charges were never pursued. The legacy of the alleged corruption is that today Tanzania has a plant with construction costs that are among the highest for similar size/technology IPPs in the developing world for no particular reason (other than poor planning and/or execution). On the other hand, it has a plant that did reduce the country's load shedding during acute power shortages, serving as an important insurance policy, and has since been termed 'a saviour', even by stakeholders who indicate that corruption was likely.

In terms of the project partners, local partner VIP took IPTL to court shortly after the plant commenced commercial operations due to oppression by the majority shareholder, alleged business fraud and failure by Mechmar to contribute equity. VIP has also since objected to an attempt by IPTL to devalue VIP's shares. The dispute, which reflects the poor investment outcomes for the local partner, may also ultimately impact on the project debt, due to the fact that VIP has petitioned to cancel the recent sale of the project's debt to Standard Chartered.

Project financing, which was initially hard to come by, is at the root of the local partner's dispute, with VIP arguing that the project was financed 100% by debt. IPTL management counters this allegation insisting that Mechmar did contribute equity, but the project became highly indebted during the arbitration period (1998-2001) and therefore the project was required to devalue shares. As of the writing of this paper, these issues remain unresolved.

IPTL's use of fuel is equally contentious. Although conversion to natural gas was specified in the 1995 PPA, the plant continues to run on HFO, which means the energy charge is at least 25% more expensive than it would be if it were running on domestic gas sourced from Songo Songo. The most common reason cited for the delay in conversion is the lack of precedent as the specific type of engine has never been converted before. Here again, however, poor planning and execution among the diverse stakeholders could have played a serious role, together with the ongoing disputes and negotiations related to the project's debt and equity. With conversion now slated to be completed by early 2007, the country will see another year of higher energy charges. Still, these charges are less than the cost of unserved energy, and therefore do not negate the more recent perception of IPTL as a well run plant that has saved the country from power shortages.

7. Lessons learned and steps forward

On the one hand, neither the development nor the investment outcomes have been particularly positive. Both IPPs have been more costly and more time consuming than originally expected. On the other hand, with the present persistent drought conditions, IPTL and Songas are indispensable, and both plants are running at full capacity. Hydro, which previously sourced nearly 100% of the electric power, is not proving a reliable basis for the sector, and even with IPPs running at full capacity, the country has been forced to shed significant amounts of its load since January 2006. What then are the lessons learned from this experience and possible steps forward?

1. Power sector planning coordination:

Tanzania's ESI was a victim of poor coordination. Coordination among different ministries, stakeholders and donors broke down during the negotiation of Songas and IPTL. This poor coordination cost the country dearly in terms of time and its many associated costs. Although it is easy to point fingers in hindsight, unless basic issues related to coordination are addressed then there is a risk of history repeating itself.

2. Power sector reform priorities:

An inevitable consequence of poor coordination is that power sector reforms have been neither clearly prioritised nor implemented. Specifically, a clear policy framework for private sector investment in the power sector remains outstanding, including the target percentage of private generation, standard investment incentives and contractual norms for the PPA. Also outstanding is a clear and feasible roadmap for how to make the main off-taker financially and technically viable. Instead the sector has gone from dealing with crisis after crisis (first drought, then high capacity charges, now drought again), delaying the planning and execution of fundamental reforms necessary for the long-term sustainability of power supply and expansion in Tanzania.

3. Independent regulation:

Several investors, among them those operating in Tanzania, have cited the importance of an independent and strong regulatory body for project success. Not only does it facilitate transparency in initial project dealings, the existence of a strong and independent regulator ensures legitimacy long after COD. Legislation to establish a regulator in Tanzania was passed in 2001, but as of the first part of 2006 the regulator remains outstanding. There has therefore been no independent oversight of the IPP process to date, and it is unclear when truly independent oversight will commence. This fact may have cost the country past and present investments and may ultimately impact on future investments.

4. Competitive bids and process:

With a crisis-based approach to power sector reform and planning, the competitive bidding process that is often instrumental in creating transparency in negotiations was not followed. One of the consequences of not following a competitive bidding procedure is that Tanzania now has one of the most costly plants in the region. Although the IPTL deal was completed quickly, any speed gained in negotiation was lost in the subsequent arbitration proceedings. This is a particularly important lesson for countries throughout East Africa currently facing drought and the need for 'emergency power'.

5. Arbitration:

While arbitration might be a useful process for resolving issues related to fairness, it may ultimately be a lengthy process that affects overall power sector development, particularly for countries such as Tanzania with a relatively high proportion of private sector generation.

6. Private sector partners and staying power:

To date, private sector investment has come at an extremely high cost, not higher than blackouts, but still high. Furthermore, many sponsors have come and gone, when the risk profile of the projects changed. Many North American and European private investors retreated, and firms from developing countries (e.g. India's Tata and Reliant) as well as firms such as Globeleq with a clearer development mandate emerged to fill the gap. These firms may, in the end, have a larger appetite for risk as well as a greater ability to diversify risk over their portfolio of assets. In this context, there is a clear need for countries to commit to the right private sector partner, and vice versa. Caution must be taken to ensure that those present at the negotiating table are looking for a long-term mutually beneficial relationship, which will allow both investment and development outcomes to flourish.

7. Currency devaluation and local capital:
A final observation and lesson is that although Tanzania has not experienced major macroeconomic shock and a radical depreciation of its currency, throughout the 1990s, the currency lost significant value. With PPAs denominated in USD, there is a potentially substantial impact of depreciation on the cost of power in local terms, particularly given the 20-year duration of contracts. The use of local capital is emerging as a solution to mitigate the impact of currency depreciation. Examples are evident in North Africa, particularly in Morocco, which has recently completed an IPP 100% financed by local capital. Although Tanzania's financial markets may not yet be sufficiently deep to finance IPPs 100%, steps may be taken in this direction in partnership with foreign investors and donors to work toward greater country ownership of projects.

Appendix A: Project costs

Table A.1: IPTL project costs
Source: ICSID, MEM, TANESCO

IPTL	*Project costs (US$ million)*		*Financing*
Projected total project cost	163		
Actual total project cost (post-arbitration)			
EPC Contract	98.2		
Construction contingency	4.9		
Land	1		
Insurance	4.1		
advisors (lenders, project)	3		
working capital	1.7	70% debt (at 8.5%)	30% equity
fuel oil reserve	3.2		
interest during construction	4.6		
financing & agency fees	1.9		
misc[1]	4.6		
total project costs for diesel	**127.2**		
Conversion to natgas			
estimate in ICSID	11.6		
2005 estimation by Wartsila	20	TANESCO	
Total project costs post conversion	**147.2**		
Note: 1 Misc includes funds termed 'development', 'mobilization and 'commitment fees'			

Table A.2: Songas project costs
Source: PAD, Songas personal interviews, TANESCO, MEM

Songas	*Project costs (US$ million)*		*Financing*
Initial Songas costs			
gas processing and pipeline	100		
assumed loans for turbines 1-4 (115 MW)	45		
work done on wells	25	70% debt (on-lent	30% equity
Overhaul/refurbishment and conversion of turbines 1-4	35	by GoT at 7.1%)1	
balance of plant costs2	61		
total for 115 MW project, delivered July 2004	**266**		
Songas expansion			
turbine 5 (35 MW)	7.1	100% equity (Globeleq)3	
turbine 6 (40 MW)	14		
balance of plant costs for expansion	28.9		
total for 75 MW expansion	50		
total on which (2005/present) capacity charges calculated	316		

Table A.2 (continued)

	Project costs (US$ million)	Financing
Additional Songas costs incurred by GoT		
drilling of original wells	100	Sunk cost, GoT (concessionary loans 1970s)
AFUDC	103	Treasury (40%), TANESCO (10%), Escrow (50%)
escrow account	50	surcharge on fuel (used to pay down AFUDC), presently now only US$2.5 mill.
liquidity facility of 4 months capacity on 115 MW	16.8	interest on the escrow
total additional costs	220	Note: does not include escrow since used to pay down AFUDC
Total project costs	**536**	

Notes:
1. *Songas equity:* Total equity for original scope is US$60 million. Globeleq (US$33.8 million), FMO (US$14.6 million), TDFL (US$4 million), CDC (US$3.6 million), TPDC (US$3 million-in kind) and TANESCO (US$1 million-in kind). *Songas debt:* Total debt is US$206 million. IDA (US$136 million), EIB, (US$55 million), Sida, (US$15 million). In reference to the IDA loan, US$108 was sourced from the World Bank Credit 3569-TA. In addition, the old loans from previous credits and grants include US$22 million (salvage value) for UGT3 and UGT4 LM600 GE turbines installed at Ubungo in 1995; and US$8 million paid out of the Sixth Power Project for Songo Songo wells work-overs in 1996/7. Sida contributed a grant to GoT but the loan to Songas equivalent to US$15 million (salvage value) for UGT1 and UGT2 ABB GT10A in 1994.
2. Balance of plant costs' refers to refurbishment of plant, building of warehouse, as well as soft costs, e.g. project management, build up of O&M, [3]refinancing of turbines 5 & 6 currently under discussion.

Notes

1. References to both the Government of Tanzania (GoT) and the Ministry of Energy and Minerals (MEM) are made repeatedly throughout the paper. While MEM is part of GoT, it should be noted that explicit reference to GoT implies that stakeholders may have included, but were not limited to those, in MEM.
2. Over 30 interviews were conducted with more than 20 stakeholders in January, February, August, November and December 2005 in Dar-es-Salaam, Washington D.C. and via teleconference in London. Interviews were followed by email correspondence (through mid-2006) to clarify discussion points. Stakeholder interviews included present and former directors and managers at EastCoast Energy, Independent Power Tanzania Limited (IPTL), Songas, Ministry of Energy and Minerals (MEM), Parastatal Sector Reform Commission (PSRC), Tanzania Petroleum Development Corporation (TPDC), VIP Engineering Limited (VIP), Tanzania Electric Supply Company Limited (TANESCO), NETGroup Solutions, Swedish International Development Cooperation Agency (Sida), and the World Bank. Due to sensitivity of data, stakeholders have not been identified by name and are only identified by organizational affiliation in the text.
3. The paper is part of a global IPP study, led by Stanford University's Program on Energy and Sustainable Development (PESD), which includes detailed reports on twelve different countries. The overarching purpose of the study is to evaluate the IPP experiences across a number of countries and projects and thereby glean best and better practices for the future. See http://pesd.stanford.edu/docs/ipps.php for information on PESD IPP study.
4. For a more detailed assessment of effect of IPPs on the performance of the electricity management contract, see the upcoming MIR case study on the Tanzania Electricity Management Contract (Ghanadan and Eberhard 2006).
5. Several small self-producers also sell power to TANESCO, including Tanwat (2.5 MW), Kiwira Coal Mine (6.0 MW)—which were the first two IPPs—-and Kilombero Sugar (2.5 MW). However, they sell only small amounts of excess power, and thus are not treated within the scope of this study.
6. As of 2005, the project was supplying seven additional firms with gas.
7. This paper is based on a longer study by MIR detailing Tanzania's IPP experience, which includes a detailed narrative of the development of the two plants, available at: http://www.gsb.uct.ac.za/gsbwebb/mir/documents/TanzaniaIPPfinal_March2006.pdf
8. Globeleq, focused exclusively on emerging markets in Africa, Latin America and Asia, was spin off of the UK Commonwealth Development Corporation in 2002. Presently CDC Group Plc is the sole shareholder. Therefore, although the firm operates with a private sector mandate, it has been largely influenced and supported by its development origins.
9. The reason why Ubungo turbine VI was not included in the original gas deal is due to the fact that it was not

part of the original project concept.

10. Stakeholders in the MEM indicate that fuel savings will be even greater for IPTL, at 60% (not 75%) of present costs, based on HFO prices. In addition, further reductions in cost may result from the increase in the efficiency of the plant running on natural gas.
11. It should be noted that pipeline capacity, although not cited by stakeholders as an impediment to conversion, is 110 million standard cubic feet per day (mmscfd). Currently the pipeline capacity is utilized at 42%. With two emergency projects due online (45 MW Tegata plant and 60 additional MW at Ubungo) and the IPTL conversion (100 MW), the pipeline will be utilized at 100% with a buffer of approximately 20mmscfd.
12. The utility is still paying the EIB portion of its subordinated debt, i.e. it only applies to the World Bank portion of the debt.
13. With regard to the equity contribution, IPTL maintains that equity has been contributed by Mechmar; the firm's financial situation has changed drastically, however, since the arbitration, during which period, IPTL incurred significant debt.
14. Using natural gas as a fuel makes Songas also more efficient from a fuel usage perspective.
15. Additional costs related to Songas: 1) the AFUDC was paid down by GoT, Treasury and Tanesco for US$103 million to reduce the capacity charge; 2) the subordinated portion of Songas World Bank debt is currently not being paid; 3) the escrow facility of US$50 million (which was used to help pay down the AFUDC is presently only US$2.5 million) but did until 2003 tie up GoT funds; 4) the cost of the original drilling of the wells, which amounted to approximately US$100 million, is as indicated above, treated as a 'sunk cost'.
16. This framework stems from the global IPP research program undertaken in collaboration with Stanford's PESD (see footnote 3 for further details).
17. This is calculated by taking: the total project cost (debt US$206 million + equity US$60 million), divided by the product of 12 months and monthly energy saving (replacing Jet A-1 fuel with natural gas) of about US$3.5 million for UGT1 -UGT4, by the then prices, which means that the payback period is almost 6.33 years. Since Jet A-1 prices doubled last year, the payback period is reduced by half to almost 3 years.
18. Insofar as there was no organized competitive bid for IPTL, it is difficult to evaluate the direct impact of the investment climate on the bid.
19. It should be noted that this figure does not reflect the positive VAT receipts that the GoT receives.
20. The World Bank exerted significant pressure on GoT to cancel the IPTL plant. According to MEM and World Bank personnel, the Bank made no attempt, however, to cancel the Songas project for the following reasons: it fit the Power System Master Plan; cost of production was comparatively favourable; and there were no allegations of corruption.
21. Stakeholder in GoT has indicated that Songas would have gone ahead after AES's exit even without Globeleq or a 'Globeleq type firm'. At the time that AES exited, construction was nearly complete. GoT would therefore have completed construction with funds from the escrow facility. Furthermore, provided AES had not found a willing buyer and opted to leave the project, the GoT would not have been required to pay down the AFUDC. There would be no ROE expected and the capacity charge would have dropped to US$2 million for the original scope (turbines I-V).

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