ECONOMIC ANALYSIS

A. Introduction

1. The economic analysis of the Takhiatash Power Plant Efficiency Improvement Project was conducted in accordance with Asian Development Bank (ADB) guidelines to measure the projected costs and benefits at 2013 constant prices for an operating period of 25 years after construction.[1] The economic internal rate of return (EIRR) was calculated by discounting the incremental annual costs and benefits arising from the comparison of the with-project and without-project scenarios. Sensitivity analysis was conducted to ascertain the robustness of the analysis. All financial prices have been adjusted to economic prices by applying corresponding conversion factors.

2. The project aims to overcome the anticipated demand–supply gap and operational deficiency at the aging Takhiatash thermal power plant (TPP). Total power demand in 2012 from the Karakalpakstan and Khorezm regions was 2,293 gigawatt-hours (GWh). It is projected that total demand will grow at 3% per annum as a result of increasing industrial activities in the two regions. Total net power generated in 2012 by the Takhiatash TPP was 2,974 GWh and is projected to decrease as existing turbines become obsolete. As the main power supplier for these two regions, the Takhiatash TPP requires immediate and significant rehabilitation and upgrade to ensure steady and reliable power supply and address unmet demand.

3. The project involves constructing two combined-cycle gas turbine (CCGT) units, each with an installed capacity of 255 megawatts (MW), and retiring three turbines that are between 39 and 44 years old. The CCGT technology allows for efficient power generation and will result in energy savings and reduction of carbon emissions. The soft component of the project comprises the implementation of a 2-year capacity development program at Uzbekenergo, the state-owned power utility, and construction of a social center in the community of Takhiatash.

B. Demand Analysis

4. In 2012, the regions of Karakalpakstan and Khorezm consumed 2,293 GWh of power supplied by the Takhiatash TPP and the Tuya Muyun hydropower plant (HPP). Regional demand has remained stable over 2006-2012 at an average annual growth rate of about 1%.

Table 1: Historical Regional Demand

Demand (GWh)	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Karakalpakstan	960	969	977	985	1,004	1,091	1,106
Khorezm	1,083	1,091	1,102	1,121	1,125	1,170	1,187
Regional demand	**2,043**	**2,060**	**2,079**	**2,106**	**2,129**	**2,261**	**2,293**
Losses	450	453	457	463	468	498	504
Evacuation to national grid	801	781	758	725	697	737	736
Total demand for region	**3,294**	**3,294**	**3,294**	**3,294**	**3,294**	**3,496**	**3,533**

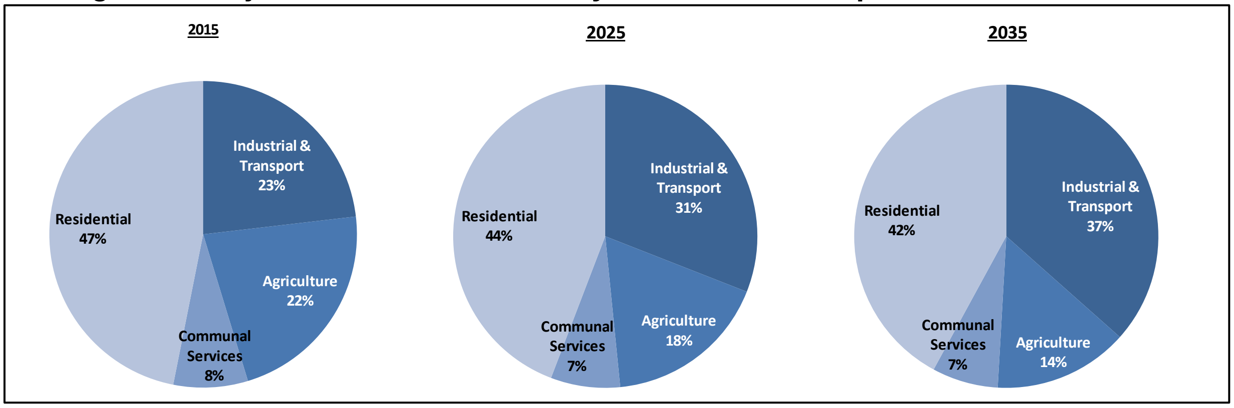
Source: Uzbekenergo statistics.

5. The Takhiatash TPP is the major power source for the two regions since the Tuya Muyun HPP produces only an average of 220 GWh per year. The TPP is also connected to the national grid but its supply to the grid is constrained by the limited transmission capacity, which is capped at 800 GWh per year. System losses approximate 22%.

[1] ADB. 1997. *Guidelines for the Economic Analysis of Projects.* Manila.

6. According to Uzbekenergo, power demand in the region is expected to grow by 3% per year. Currently, the greatest demand for power comes from residential customers at 47% of total power consumption, followed by industrial and transport at 23%, agriculture at 22%, and communal services (including public and commercial activities) at 8%. It is expected that increasing industrial activities—exploration of oil and gas, mining, construction of petrochemical plants, and traditional manufacturing—will contribute the bulk of projected growth. Total demand from industrial activities will account for 39% of total power demand from Karakalpakstan and Khorezm by 2040. Total power demand will reach 2,907 GWh in 2020, 3,543 GWh in 2030, and 4,319 GWh in 2040.

Figure 1: Projected Demand Growth by Sector in Karakalpakstan and Khorezm



Source: Uzbekenergo statistics.

7. It is expected that with the rehabilitated infrastructure and an increase in operational efficiency at the TPP, system losses will steadily decline to 16% in the medium term. Demand from the national grid is estimated to remain at the level of 2013, or about 736 GWh a year. Total power demand for the TPP and HPP is expected to reach 5,689 GWh by 2040.

Table 2: Regional Demand Forecast

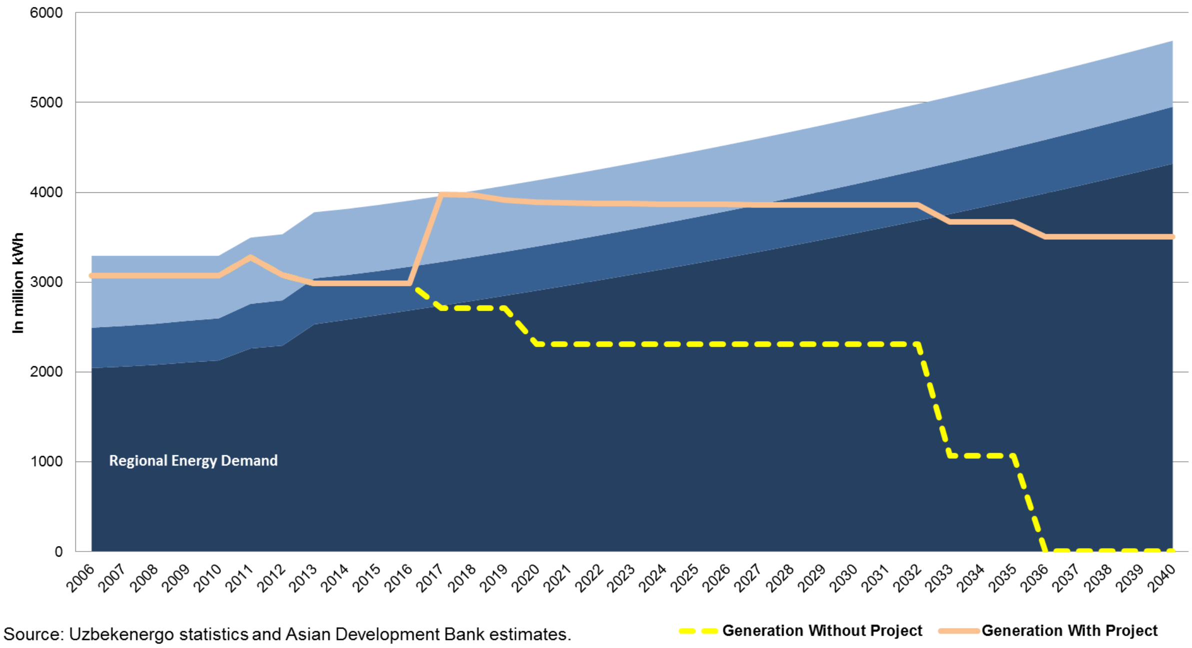
Demand Forecast (GWh)	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Karakalpakstan	1,241	1,370	1,513	1,670	1,843	2,036
Khorezm	1,392	1,537	1,696	1,873	2,068	2,283
Regional demand	**2,633**	**2,907**	**3,209**	**3,543**	**3,911**	**4,319**
Losses	490	491	514	547	588	634
Evacuation to national grid	736	736	736	736	736	736
Total demand for region	**3,859**	**4,134**	**4,459**	**4,826**	**5,235**	**5,689**

GWH = gigawatt-hour.
Source: Uzbekenergo statistics.

8. However, the aging TPP will not be able to cope with the growth in demand. The project will address the anticipated gap between demand and supply. Current net generation at the TPP is below 3,000 GWh per annum and will be further reduced to 2,300 GWh by 2020, when turbines 1, 2, and 3 become obsolete in 2016 and 2019. The remaining turbines (7 and 8) will operate until 2035, when they reach the end of their technical life of 45 years. Without rehabilitation or upgrade, TPP will not be able to provide sufficient power to meet increasing domestic demand. Furthermore, given that the TPP is the main power source for the two regions and that existing capacity of the transmission infrastructure connected to the national grid is constrained, energy security will become a serious issue and will have an adverse impact on the regions' economic growth.

9. With the construction of the two CCGT units and based on current demand projection, the TPP will be able to operate at a higher efficiency rate and ensure stable power supply to the region until at least 2034.

Figure 2: Without-Project and With-Project Comparison



Source: Uzbekenergo statistics and Asian Development Bank estimates.

C. Least-Cost Analysis

10. The project is considered the least-cost option to ensure sufficient generation capacity and cost efficiency. Under a without-project scenario, the reliability of power supply will significantly diminish when the existing infrastructure becomes obsolete. Not only operation and maintenance (O&M) costs will increase, but the risk of an accident will also rise. Among various types of power generation plant, the CCGT technology is the most reliable and cost-effective solution. It is considered the most energy-efficient and environment-friendly option compared with other fuel combustion technologies. Furthermore, with the proposed cooling and closed refrigeration systems, the project is expected to achieve the highest rate of power generation with the lowest rate of air emission pollutants compared with other open-cycle technologies. The proposed multi-shafted configuration is the most cost-effective in the long term and ensures the highest reliability.[2] Other alternatives, such as construction of power generation plants in other parts of the Karakalpakstan and Khorezm regions, will involve higher capital and O&M expenditures. The option of transmission via the national grid from other power sources outside these two regions is limited by the constrained capacity of the existing transmission infrastructure and would increase transmission costs and system losses.

D. Project Benefits

11. Incremental benefits from the project include the sale of the incremental power generated at an economic price of $0.162 per kilowatt-hour (kWh). A willingness-to-pay study

[2] Includes one gas turbine, one heat-recovery steam generator, and one steam turbine for each unit.

was conducted and indicated that the residential consumers are willing to pay $0.325 per kWh, which is six times higher than the 2013 consumer tariff of $0.053 per kWh.

12. The consultant hired under project preparatory technical assistance conducted a survey to assess the willingness of households in the Karakalpakstan and Khorezm regions to pay for electricity. A sample of 900 households was selected based on the demographic profile of the two regions, with 15% non-poor and 85% poor households.[3] The survey shows that the non-poor households are willing to spend about $50.7 dollar per month on generator and fuel; whereas the poor households will spend $19.7 per month on candles, kerosene, oil lamps, and fuel as substitute for electricity. In conclusion, the survey indicates that the households in the two regions are willing to pay $0.325 per kWh. $0.162 per kWh has been calculated based on tariff and the consumer surplus (40% of the difference between the willingness to pay and tariff) for estimating the incremental electricity supply in the economic analysis of the project.

13. Nonincremental benefits comprise gas savings as a result of more efficient operation by the two CCGT units. Border price was used for the gas price. The potential sale of additional Clean Development Mechanism rights arising from lower carbon emissions thanks to the project was not included.[4]

E. Project Costs

14. Project costs have been converted from financial prices to economic prices. The total project-based cost includes the total capital investment cost, peripheral infrastructure, and physical contingencies. A standard conversion factor of 0.91 has been applied to the non-traded goods component. In addition, a shadow wage rate factor of 0.8 has been assumed for local unskilled labor applicable to 25% of local costs. Adjustment has been made to the O&M cost, which includes labor, fuel and water costs, and maintenance of equipment and machinery. The international gas price has been applied to calculate the fuel cost as it is considered the opportunity cost of domestic natural gas.

F. Economic Internal Rate of Return

15. The EIRR of the project is 32.6%, which compares favorably with the economic opportunity cost of capital of 12%.

[3] Households living below the poverty threshold of $1.5 per capita per day (household survey results and Poverty Social Assessment Report).
[4] At $0.3 per ton the impact on the EIRR is minimal and therefore not taken into account in the analysis.

Table 3: Project Economic Internal Rate of Return
($ million)

Year	Incremental Electricity	Fuel Savings	Capital Investment	Operational Costs	Net Benefits
2014	0	0	(15)	(3)	(17)
2015	0	0	(51)	(3)	(54)
2016	0	0	(73)	(3)	(75)
2017	162	6	(172)	(48)	(53)
2018	161	41	(141)	(71)	(10)
2019	154	41	(81)	(68)	45
2020	202	29	0	(79)	152
2021	201	29	0	(78)	152
2022	200	29	0	(77)	152
2023	199	29	0	(77)	152
2024	199	29	0	(76)	152
2025	199	29	0	(76)	152
2026	198	29	0	(75)	152
2027	198	29	0	(75)	153
2028	198	29	0	(74)	153
2029	198	29	0	(74)	153
2030	198	29	0	(73)	154
2031	197	29	0	(72)	154
2032	197	29	0	(72)	155
2033	332	14	0	(103)	243
2034	332	14	0	(102)	243
2035	332	14	0	(101)	244
2036	448	0	0	(128)	320
2037	448	0	0	(127)	321
2038	448	0	0	(126)	321
2039	447	0	0	(125)	322
2040	447	0	0	(125)	323
2041	447	0	0	(124)	324
	6,741	508	(533)	(2,234)	4,481
		EIRR			**32.6%**

EIRR = economic internal rate of return.
( ) = negative.
Source: Asian Development Bank estimates.

G. Sensitivity Analysis

16. Sensitivity analysis was conducted to assess the economic viability of the project by varying key projections and the result indicates that the EIRR is sufficiently robust.

Table 4: Results of Sensitivity Analysis of the Project

Item	**EIRR (%)**
Base case	32.6%
Increase in capital costs by 20%	27.0%
Increase in O&M costs by 20%	31.2%
Decrease in revenues by 20%	22.5%
Excluding CDM Benefits	32.6%

CDM = clean development mechanism, FIRR = economic internal rate of return.
Source: Asian Development Bank estimates.