NOVA SCOTIA POWER
An Emera Company

August 6, 2010

Ms. Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
Halifax, NS B3J 3S3

Re: Nova Scotia Power Inc. – TUC6 Waste Heat Recovery Project - CI 28098 – Authority to Overspend (ATO) - P-128.07

Dear Ms. McNeil:

Please accept this letter as the Reply Submission of Nova Scotia Power Inc. (NSPI, the Company) in respect of the above noted ATO application for Tufts Cove Unit 6 (TUC6, the Project).

On May 3, 2010, NSPI filed this ATO with the Utility and Review Board (UARB, the Board) requesting approval to overspend on this Project in the amount of $8,699,864. The Board provided notice to the participants in the original capital work order application and established a timeline for responses to Information Requests by NSPI and the filing of submissions by intervenors.

Written submissions were received from three parties:

1. The Nova Scotia Department of Energy (NSDOE)
2. NewPage Bowater (NPB)
3. Avon et al. (Avon)

No intervenors filed evidence in this ATO proceeding. Each submission received was in the form of legal argument. The only evidence before the Board is that filed by NSPI.

While cost increases incurred have either resulted from changes which will provide future customer benefits or unexpected circumstances, the benefits of the Project have been sustained through NSPI's efforts to preserve or increase the otherwise reduced net present value (NPV). None of the intervenor submissions would suggest denial of full cost recovery. NSDOE endorses the application on its merits. The submissions of these intervenors implicitly conclude that TUC6 delivers significant benefits to customers.

In this Reply Submission, NSPI will respond specifically to the issues raised by intervenors. The comments raised by the intervenors related to the following two issues:

1. Net Present Value of the Project and 2010 Savings
2. Contingency

NPV and 2010 Savings

As previously stated in NSPI's May 3, 2010 application, the Project retains a very positive NPV which would not have changed the decision to proceed originally. The following factors led to the business decisions made by NSPI, which continue to demonstrate the delivery of significant customer benefits:

1. Infrastructure and Environmental Requirements

2. Maintenance of the Project Schedule

3. Incorporation of Design or Equipment Specifications to Ensure Plant Optimization and Deliver a Long-Term Low Operating Cost Generating Facility

A discussion of these items is provided below.

1. Infrastructure and Environmental Requirements

NSPI provided the following explanation for the cost variance associated with this cost element in UARB IR-9:

> *In late 2008, the harbour infill was one of the first technical issues addressed. Information exchanges were ongoing as the detailed engineering progressed in parallel with discussion with Department of Fisheries, Nova Scotia Environment and Navigable Waters. Detailed engineering resulted in changes when it became clear the infill was technically unsuitable as the slope had to be increased for stability and this would result in the toe of the slope being off of NSPI property. Additional sheet piling was required to resolve this. The intake and discharge channels were also affected by the infill at the required slope so the design incorporated more sheet pile.*
>
> *With this design, NSPI was able to obtain authorization from Fisheries and Oceans on June 17, 2009; Navigable Water Protection Program on June 30, 2009; and Construction Approval from Nova Scotia Environment on July 2, 2009. The permits were received three months beyond the anticipated project plan date.*

2. Maintenance of the Project Schedule

The original project schedule forecasting the June 2010 in-service date was affected by the steam turbine generator selection. NSPI originally anticipated that Board approval would be received in June 2008. Details regarding the delivery time of the steam turbine generator were not finalized at the time the original application was filed. NSPI finalized the technical specifications during the detailed negotiations for the award to the steam turbine generator vendor following approval of the capital work order approval in September 2008.

Through the course of detailed engineering, various design challenges were encountered which, if not resolved, could have negatively impacted the in-service date or the year round operating performance of the unit. Efforts to address these and other challenges are outlined below.

In 2007 and early 2008 it was a seller's market for utility equipment and NSPI received little interest from the marketplace for the supply of the steam turbine generator for this project. This was due to the increased global demand for new generation, and at a 50 MW size, the steam turbine generator is at the low end of utility-grade size, more commonly applicable to industrial grade machines. As a result, most potential suppliers indicated delivery times could be as much as 18 months later than required to meet the TUC6 project schedule. NSPI recognized the significant benefit for customers by completing this Project and capturing the waste heat as soon as possible.

After considering alternative procurement approaches, NSPI was able to successfully procure a steam turbine generator from Mitsubishi through leveraging its relationship on the Trenton 5 Generator Replacement Project and by committing to reserving a manufacturing slot, which was at shareholder risk, but necessary to preserve customer benefits. During negotiations, NSPI and Mitsubishi examined axial and bottom steam discharge condenser arrangements. The axial discharge configuration was chosen primarily on acceptable delivery timelines and a slightly lower cost for the steam turbine generator. Further discussions with Mitsubishi led to selecting a physically smaller machine with a shorter last stage blade design because it offered reductions in size and weight yet provided slightly better performance for the unfired design conditions. NSPI considered the 25 inch blade machine to offer the optimal solution considering capital cost, operating performance and equipment delivery.

Had NSPI waited for the steam turbine generator with the bottom steam discharge configuration to become available in the manufacturing capacity, the project in-service date would have been delayed until at least November 2011. Attachment 1 to this Reply Submission is presented as a sensitivity analysis of the in-service date on the project benefits. The Attachment provides a project economic analysis showing the NPV of the May 2008 Project including the original steam turbine generator configuration, all original cost inputs, with an in-service date of November 2011, and compares it to the ATO Filing with a December 2010 in-service date.

The analysis indicates that the NPV benefit of the Project is significantly maintained by NSPI's decision to obtain the Mitusbishi steam turbine generator and the related modifications thereby maintaining the 2010 in-service.

It is important to note that all analyses of the duct-fired project should be considered conservative insofar as the duct-fired benefit portion as calculated by the Nova Scotia Wind Integration Study (prepared by Hatch for the Nova Scotia Department of Energy) was only estimated to 2020. Therefore, the continued wind integration benefits that would be derived from the Project beyond 2020 are not factored into any analyses.

3. Incorporation of Design or Equipment Specifications to Ensure Plant Optimization and Deliver a Long-Term Low Operating Cost Generating Facility

Condenser

Condenser specification involves matching its operating performance, (i.e. temperature and backpressure) to the turbine as well as taking into consideration long-term maintenance aspects such as cathodic protection, protective coatings and materials selection related to operations in a salt water marine environment. The axial steam discharge turbine requires a relatively high minimum operating backpressure which is different from other larger turbines which NSPI is operating across its thermal generation fleet. The selected steam turbine design was optimized by the supplier to match the more common application of air-cooled condensers, in this size range, which functionally operate at higher backpressure. While it is less common to match turbines of this size with sea-water cooled condensers, NSPI is fortunate to be able to use the sea-water directly from Halifax Harbour for this Project and take advantage of sea-water cooling which is more efficient than air cooling, requires far less physical space on site and does not create additional noise from associated air handling equipment. However, design challenges have been encountered in optimizing the condenser size and circulating water (CW) pump size to provide suitable operating modes for all combinations of sea-water temperature across all steam load conditions. NSPI considered and modeled combinations of CW pumps and variable speed drives while seeking operating variance allowances while preserving warranties and performance guarantees from Mitsubishi on the steam turbine low load operating performance.

After considerable analysis, NSPI engineers were able to specify an appropriate condenser arrangement which involved dividing the waterbox in order to reduce the cooling surface available during winter conditions when the sea-water is very cold and the steam plant may be operating at or near minimum load. NSPI has consistently designed its thermal generating units with the ability to operate over a wide load range which provides for future operating flexibility, minimizes steam turbine final blade deterioration, and considers the optimization of the condenser and CW system to the steam turbine a key design feature. Please refer to UARB IR-14, Attachment 1 for the technical correspondence relating to the condenser arrangement.

Several unexpected related costs resulted; a) the CW pumps were larger than initial allowances because the condenser had to be positioned at a higher elevation to align with the axial steam turbine which required additional head to pump the sea-water higher than would have been the case for a more traditional arrangement with the condenser mounted under the turbine; b) the foundation for the condenser was more expensive than originally anticipated as the higher condenser elevation had to be considered in the foundation seismic loading and the operating forces; c) the building was reduced slightly in height but had to be increased in length to accommodate the axial steam turbine arrangement and this increased the cost of the overhead crane in particular.

There are additional operating benefits associated with dividing the waterbox which allows half of the condenser to be accessed for tube cleaning and/or repairs while the other half remains in service allowing the unit to remain in service and providing for a high availability unit.

Circulating Water Pumps

The development of the physical layout, while taking into consideration the steam turbine and condenser operating conditions, was being studied in concert with the circulating water pump selection. The pump suppliers were contacted for details on various pump sizes and performance characteristics to use in modeling the flows and pressures. NSPI tendered for two sizes of pumps to evaluate the option of using a smaller size pump, as contemplated by the original capital work order, in the shoulder season to better match the cooling requirements of the condenser during minimum load conditions. After evaluating pump costs versus power savings, the decision was made to not pursue the smaller pump option as the operating advantages, such as power consumption did not support the capital expenditure and the operating curves for the two different size pumps were very difficult to match for full load conditions. Dividing the condenser waterbox as noted above, was a better option.

Boiler Feed Water Pumps

The Boiler Feed Water (BFW) pump selection was affected by changes in the pump discharge pressure requirements as a result of finalizing the design and feedwater piping details of the once-through-steam-generator. Engineering analysis considered pump types and typical operating efficiencies, related piping design, and requirements for pump flow rate protection at minimum load. NSPI made the decision based on engineering judgment to specify and purchase combination high pressure and low pressure pumps when it became apparent that this offered a lower capital cost and an effective design for both performance and long term maintenance of this critical equipment. At the same time, the decision was made not to accept Automatic Recirculation Valves offered as a pump option. NSPI chose to use separately purchased valves with motorized control to provide minimum recirculation for the pumps protecting them from overheating at minimum flow conditions. This provides a robust and reliable method of protection which is also in line with utility standards and actual NSPI operating experience.

Operating Savings Resulting from Automation

Incremental costs associated with the increased automation of the facility are offset by the ongoing operating costs which would otherwise be required to staff this facility.

The economic effect of staffing the unit is provided in Attachment 2. The Project's NPV is affected by two items. The incremental capital expenditure associated with sustaining automation are offset by the increase in labour cost savings which are made possible. NSPI believes the increased automation will allow for an operating complement of one power engineer per shift to 24/7 coverage, conservatively five additional power engineers, which avoids a project NPV deterioration of approximately $2.3 million.

General

All of the decisions for this Project were made with the technical information available at the time and were considered by teams consisting of design engineers, operating engineers, maintenance staff, and suppliers' technical support staff. While doing its best to maintain the project schedule, NSPI's goal was always to select designs and equipment that would provide the best value over the expected life of the plant, the lowest overall operating cost and deliver significant customer benefits. Had NSPI not advanced the steam turbine procurement, condenser and CW design to minimize adverse effects on the Project in-service timeline, the Project would have been significantly delayed, resulting in a reduced project NPV than that which NSPI has been able to preserve.

Avon and NPB have questioned the impact on benefits to ratepayers as a result of the in-service date being late 2010. As discussed in the foregoing, regulatory approval was obtained approximately three months later than originally anticipated in the project schedule, while environmental permitting was obtained approximately three months beyond the project plan schedule. These factors contributed to the change in the original forecast in-service date to the current forecast date. In NSPI's Supplemental Evidence for the capital work order application filed May 28, 2008, NSPI presented a revised in-service date of Q4 2010. At that time, NSPI stated that this date was predicated on a June 2008 decision date and indicated that otherwise the in-service date would be delayed and first year savings would be foregone. See NSPI Supplemental Evidence, P-128.07, May 28, 2008, page 11.

As a result of the prudent steps taken by NSPI, the construction schedule has been preserved in 2010 where otherwise a delay until at least November 2011 would have resulted. The fuel benefits associated with this project will begin to materialize once the project becomes operational.

A total savings of $5.5 million is attributable to 2010. The approximate $4.2 million in tax savings which were forecast for 2010 and attributable to this Project have been sustained by preserving a 2010 in-service date. Customers will benefit now also from savings in operational costs of approximately $1.3 million in 2010. Had NSPI not advanced the turbine and condenser design changes, the Project in-service date would have been significantly delayed beyond December, resulting in lower value for customers.

Avon argues that the cost exceedances should be borne by NSPI shareholders particularly where the NPV of the Project has declined and fuel savings did not materialize. Avon has not provided evidence of, nor argued imprudency on the part of NSPI. As shown in Attachments 1 and 2, NSPI's decisions in this matter have served to preserve value for customers. All costs have been reasonable and prudently incurred and are appropriate to be recovered from customers. NSPI has acted in the best interests of customers and has presented an ATO which confirms that the Project economics remain strong and result in significant savings to customers over the life of the Project.

Contingency

NSDOE, Avon, and NPB have each raised questions regarding the contingency amount of $7,213,207 which was included in the Board approved capital work order for this Project.

Inclusion of a contingency amount in capital work orders is an appropriate and prudent approach to capital work planning and contingency amounts are routinely included to provide for an allowance for items/details not finalized in capital work order applications approved by the UARB. Its purpose is to provide an allowance for items not addressed in the design phase and/or to address normal project cost variances.

It is incorrect to suggest that NSPI's overspend is actually more than the amount requested in this ATO. The ATO is a request to spend $8,699,864 over the Board approved amount of $84,296,764. NSPI further confirms that there is no unallocated contingency included in this ATO.

Conclusion

The evidence available to the Board in this application demonstrates that the steps taken by NSPI during planning and construction of this Project were reasonable, prudent and led to significant preservation of value for NSPI customers.

The evidence of the Company establishes that the ATO application proposed for TUC6 is the best economic option for customers, and provides significant benefits to the integration of renewable generation. The justification for the project remains as approved by the Board in 2008. The cost increases forecast for this Project are associated with specific cost drivers unforeseeable at the time of filing the capital work order with the UARB.

NSPI respectfully requests Board approval of the ATO for CI 28098 as filed.

Yours respectfully,

Eric Ferguson, CMA
Director, Regulatory Affairs

Attach.

c: S. Bruce Outhouse, Q.C.
Mark Savory
J. Rene Gallant
Participants – P128.07 (TUC6 ATO)

TUC 6 ATO - Summary of Results:

	NPV Benefit TUC 6 without Duct-Firing vs No TUC 6 (Strategist) $M	NPV Benefit TUC 6 with Duct-Firing vs TUC 6 without DF $M	Total Project NPV Benefit $M
May 2008 Filing	43.84	31.60	75.44
2010 Revision	37.70	29.49	67.19
May 2008 - COD Nov/2011	34.64	25.65	60.29

NPV Benefit of TUC 6 No Duct Firing
May 2008 Filing with In-service date changed to Nov/2011 (was Jun/2010)

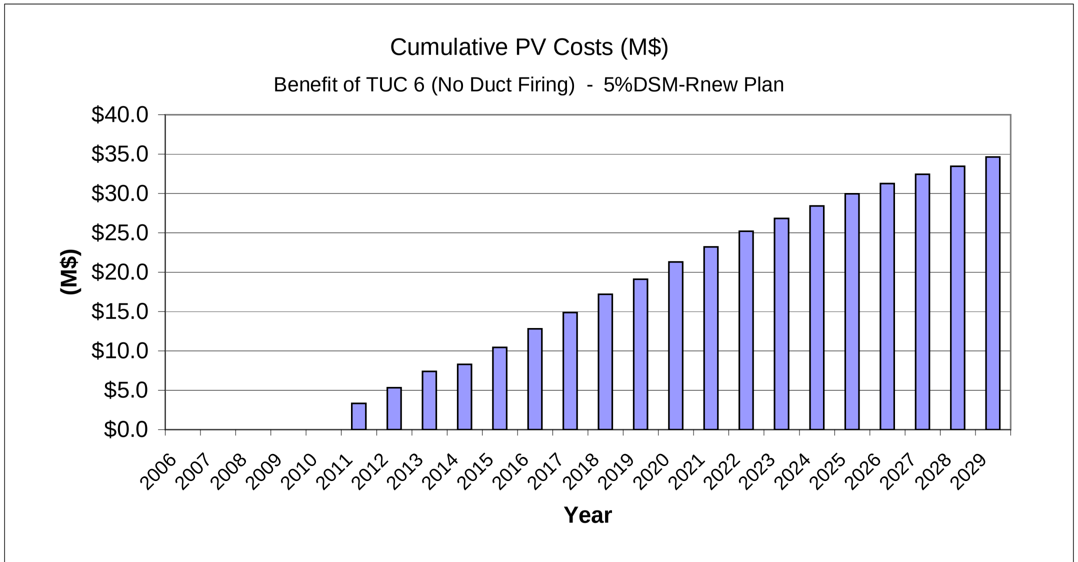
Year	Operating Costs TUC 6 No Duct Firing In-Service Nov/2011 (K$)	Operating Costs No TUC 6 (K$)	Operating Costs Nominal $ (K$)	Operating Cumulative PV Costs (K$)
2006	566,652.2	566,652.2	0	0
2007	663,192.5	663,192.5	0	0
2008	532,026.6	532,026.6	0	0
2009	541,254.8	541,254.8	0	0
2010	717,011.7	717,011.7	0	0
2011	771,147.1	772,637.8	1,491	1,082
2012	788,765.8	802,511.8	13,746	10,439
2013	840,725.0	854,444.0	13,719	19,198
2014	883,576.5	895,280.2	11,704	26,206
2015	905,351.1	919,170.6	13,820	33,968
2016	913,603.0	927,757.3	14,154	41,424
2017	940,459.8	954,166.4	13,707	48,196
2018	974,545.3	988,713.0	14,168	54,761
2019	1,010,478.0	1,023,808.0	13,330	60,554
2020	1,059,696.0	1,073,815.0	14,119	66,309
2021	1,093,568.0	1,106,891.0	13,323	71,403
2022	1,129,644.0	1,143,391.0	13,747	76,332
2023	1,167,120.0	1,179,808.0	12,688	80,599
2024	1,206,440.0	1,219,071.0	12,631	84,583
2025	1,253,072.0	1,265,561.0	12,489	88,278
2026	1,273,571.0	1,285,362.0	11,791	91,550
2027	1,295,010.0	1,306,346.0	11,336	94,500
2028	1,312,932.0	1,323,559.0	10,627	97,094
2029	1,343,989.0	1,355,432.0	11,443	99,714
		NPV (Jan. '06 K$)	**99,713.7**	**(Discount Rate is 6.62%)**

Capital Cost $70.775M

Year	Capital Costs TUC 6 No Duct Firing In-Service Nov/2011 (K$)	Capital Costs No TUC 6 (K$)	Capital Costs No DF Portion Nominal $ (K$)	Capital Costs Cumulative PV (K$)	Total Benefits PV (K$)	Total Benefits Cumulative PV (M$)
2006	232	232	0	0	0	0.0
2007	1,282	1,282	0	0	0	0.0
2008	2,710	2,710	0	0	0	0.0
2009	6,053	6,053	0	0	0	0.0
2010	11,290	11,290	0	0	0	0.0
2011	8,399	11,487	3,088	2,241	3,323	3.3
2012	22,501	11,697	-10,804	-5,114	2,002	5.3
2013	21,781	11,318	-10,463	-11,794	2,079	7.4
2014	21,267	11,037	-10,230	-17,920	882	8.3
2015	20,694	10,734	-9,959	-23,513	2,168	10.5
2016	20,166	10,439	-9,726	-28,637	2,333	12.8
2017	19,615	10,160	-9,455	-33,308	2,100	14.9
2018	19,042	9,857	-9,185	-37,564	2,309	17.2
2019	18,511	9,560	-8,952	-41,454	1,903	19.1
2020	49,185	40,504	-8,681	-44,993	2,217	21.3
2021	62,361	53,951	-8,410	-48,208	1,878	23.2
2022	60,464	52,325	-8,139	-51,127	2,011	25.2
2023	58,708	50,839	-7,868	-53,773	1,621	26.8
2024	56,811	49,214	-7,597	-56,169	1,588	28.4
2025	55,054	47,728	-7,327	-58,337	1,527	29.9
2026	52,973	45,917	-7,056	-60,295	1,314	31.3
2027	51,180	44,395	-6,785	-62,060	1,184	32.4
2028	49,427	42,913	-6,514	-63,651	1,004	33.4
2029	47,487	41,282	-6,205	-65,071	1,199	**34.6**
		NPV (Jan. '06 K$)	**-65,071.1**			
			(Discount Rate is 6.62%)			

Cumulative NPV Costs 2006-2029	**34.64 M$**

NOTE: **Operating Costs** include fuel, variable O&M, net transaction costs and fixed thermal and hydro O&M costs
Capital Charges are the annual charges for the combination of alternatives added.



Assumptions:
- 5%DSM & Rnew Plan
- No TUC 6

5%DSM-RNEW_NO TUC6_JUN4.SAV
NPV = $12,521.283 M

Assumptions:
- 5%DSM & Rnew Plan
- TUC 6 No Duct Firing
- In-service November/2011
- Capital Cost $70.775M ($2008)

TUC6 UNFIRED_$70.775_NOV2011_JUL26-10.SAV
NPV = $12,486.640 M

Incremental NPV Benefit of TUC 6 Duct Fired - Operating Cost Benefits from Hatch Analysis
May 2008 Filing with In-service date changed to Nov/2011 (was Jun/2010)

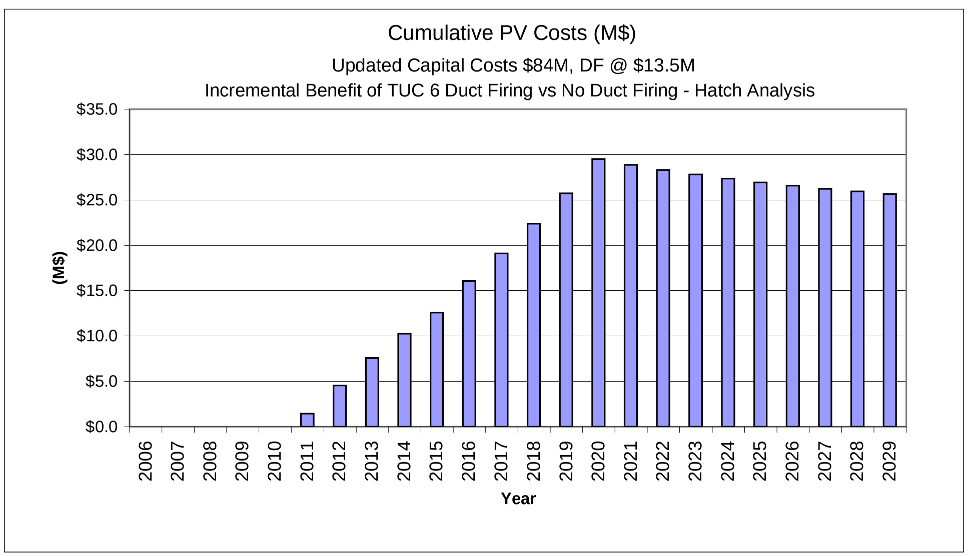
Year	Operating Benefits Hatch Analysis (K$)	**Operating Cumulative PV Costs (K$)**	Year	**Capital Cost $84.3M** Capital Costs TUC 6 Duct Fired In-Service Nov/2011 (K$)	**Capital Cost $70.775M** Capital Costs TUC 6 No Duct Firing In-Service Nov/2011 (K$)	Capital Costs DF Portion (K$)	**Capital Costs Cumulative PV Costs (K$)**	**Total Benefits Nominal $ (K$)**	**Total Benefits PV (K$)**	**Total Benefits Cumulative PV (M$)**
2006	0	0	**2006**	232	232	0	0	0	0	0.0
2007	0	0	**2007**	1,282	1,282	0	0	0	0	0.0
2008	0	0	**2008**	2,710	2,710	0	0	0	0	0.0
2009	0	0	**2009**	6,053	6,053	0	0	0	0	0.0
2010	0	0	**2010**	11,290	11,290	0	0	0	0	0.0
2011	1,386	1,006	**2011**	7,809	8,399	590	428	1,976	1,434	1.4
2012	6,639	5,525	**2012**	24,566	22,501	-2,065	-977	4,574	3,114	4.5
2013	6,732	9,824	**2013**	23,780	21,781	-1,999	-2,254	4,733	3,022	7.6
2014	6,419	13,667	**2014**	23,222	21,267	-1,955	-3,424	4,464	2,673	10.2
2015	6,052	17,067	**2015**	22,597	20,694	-1,903	-4,493	4,149	2,330	12.6
2016	8,496	21,542	**2016**	22,024	20,166	-1,859	-5,472	6,637	3,496	16.1
2017	7,971	25,480	**2017**	21,422	19,615	-1,807	-6,365	6,164	3,045	19.1
2018	8,785	29,551	**2018**	20,797	19,042	-1,755	-7,178	7,030	3,257	22.4
2019	9,402	33,637	**2019**	20,222	18,511	-1,711	-7,922	7,692	3,343	25.7
2020	10,919	38,088	**2020**	50,844	49,185	-1,659	-8,598	9,260	3,775	29.5
2021	0	38,088	**2021**	63,968	62,361	-1,607	-9,212	-1,607	-614	28.9
2022	0	38,088	**2022**	62,020	60,464	-1,555	-9,770	-1,555	-558	28.3
2023	0	38,088	**2023**	60,211	58,708	-1,504	-10,276	-1,504	-506	27.8
2024	0	38,088	**2024**	58,263	56,811	-1,452	-10,734	-1,452	-458	27.4
2025	0	38,088	**2025**	56,454	55,054	-1,400	-11,148	-1,400	-414	26.9
2026	0	38,088	**2026**	54,321	52,973	-1,348	-11,522	-1,348	-374	26.6
2027	0	38,088	**2027**	52,477	51,180	-1,297	-11,860	-1,297	-337	26.2
2028	0	38,088	**2028**	50,672	49,427	-1,245	-12,164	-1,245	-304	25.9
2029	0	38,088	**2029**	48,673	47,487	-1,186	-12,435	-1,186	-271	**25.7**
	38,087.5	**(Discount Rate is 6.62%)**			**NPV (Jan. '06 K$)**	**-12,435.0**				
						(Discount Rate is 6.62%)				

Cumulative NPV Costs 2006-2029	**25.65**	**M$**

Notes:

Operating Cost Benefits - Hatch Analysis (difference in system operating costs with TUC 6 at 125MW and 150MW)
- Hatch benefits calculated for 2011 reduced to include only 2 months of benefits because TUC 6 for this analysis is in-service Nov/2011. (8318* 2/12).

Capital Costs are the annual charges for the combination of alternatives from Strategist.



Assumptions:
- 5%DSM & Rnew Plan
- TUC 6 Duct Fired
- In-service November/2011
- Capital Cost $84.3M ($2008)

TUC6 DF_$84.3M_NOV2011_JUL26-10.SAV
NPV = $12,489.478 M

Assumptions:
- 5%DSM & Rnew Plan
- TUC 6 No Duct Firing
- In-service November/2011
- Capital Cost $70.775M ($2008)

TUC6 UNFIRED_$70.775_NOV2011_JUL26-10.SAV
NPV = $12,486.640 M

NPV Benefit of TUC 6 No Duct Firing
Revised Capital Cost ($1.5M) increase in Op Ex (labour)

	Operating Costs of 5 Power Engineers
2006	0.0
2007	0.0
2008	0.0
2009	0.0
2010	29,248.9
2011	387,840.0
2012	395,596.8
2013	403,508.8
2014	411,578.9
2015	419,810.5
2016	428,206.7
2017	436,770.9
2018	445,506.3
2019	454,416.4
2020	463,504.7
2021	472,774.8
2022	482,230.3
2023	491,874.9
2024	501,712.4
2025	511,746.7
2026	521,981.6
2027	532,421.2
2028	543,069.7
2029	553,931.0
NPV (Jan. '06 $)	**3,718,999.3**

	Capital Cost $78M	**Capital Cost $76.44M**	
Year	Capital Costs TUC 6 No Duct Firing **In-Service Dec/2010 (K$)**	Reduced capital - no remote control TUC 6 No Duct Firing **In-Service Dec/2010 (K$)**	**Capital Costs Difference Nominal $ (K$)**
2006	232	232.2	0
2007	1,282	1,282.3	0
2008	2,710	2,710.5	0
2009	6,053	6,053.4	0
2010	6,786	6,876.3	90
2011	22,761	22,535.3	-225
2012	22,615	22,396.4	-218
2013	21,993	21,779.9	-214
2014	21,430	21,222.3	-208
2015	20,885	20,682.3	-203
2016	20,308	20,111.0	-197
2017	19,747	19,555.0	-192
2018	19,201	19,014.4	-187
2019	18,622	18,440.7	-181
2020	49,285	49,109.1	-176
2021	62,450	62,279.6	-170
2022	60,542	60,377.4	-164
2023	58,774	58,615.2	-159
2024	56,866	56,713.2	-153
2025	55,098	54,950.9	-147
2026	53,006	52,864.3	-142
2027	51,202	51,066.0	-136
2028	49,399	49,268.9	-130
2029	47,486	47,361.6	-124
		NPV (Jan. '06 K$)	**-1,457.1**
			(Discount Rate is 6.62%)

- Operating Costs for 5 Power Engineers = incremental increase of $3.72M.
- Capital Cost reduction of $1.56M for no remote control equipment reduced capital costs by $1.46M over the period 2006-2029.
- Incremental increase if there is additional staffing required = $2.26M.