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Alaska Business Unit
Mid-Stream Alaska
Trans-Alaska Pipeline Pump Station Electrification

bp

Decision Support Package – Sanction
February 9, 2004

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1. Executive Overview

1.1 THE RECOMMENDATION

The Alaska Business Unit recommends rebuilding 4 of the remaining TAPS pump stations by replacing aging mainline Avon Rolls Royce direct drive turbine pumps with high efficiency turbine electrical generators and electrical pumps; and replacing existing facility housing with "non-occupied structures" that require less maintenance. Electrifying the TAPS pump stations, coupled with lifecycle control replacement, will allow automation and reduce manpower at Pump Stations 1, 3, 4 and 9. Electrifying all of the pump stations translates to an annualized Operating & Maintenance cost savings of $44mm (gross) by 2008 and will allow TAPS to forego more than $114m in expense and $44m Capital (gross) in costly upgrades to the aging Avons, associated facilities and their enclosure buildings over the next 10 years.

The BP Capital request is as follows:

$ million	Gross Project	BP Net
Capital Requested for Sanction	$172	$81
Engineering Tolerance	20	9
Reference Value for Sanction	192	90

1.2 THE HISTORY OF THE TRANS ALASKA PIPELINE SYSTEM and TAPS Overview

The discovery of a giant crude oil field at Prudhoe Bay on the North Slope of Alaska in 1968 began a period of unprecedented petroleum industry activity in the state. Construction work associated with the Prudhoe Bay discoveries included installation of production facilities on the North Slope and an 800-mile pipeline from the oil fields to a marine tanker loading facility in the city of Valdez. This pipeline system, marine loading facility, and ship escort and vessel response system (SERVS) are collectively called the Trans-Alaska Pipeline System (TAPS).

Based on forecasted production and recovery lifecycles of the North Slope fields, the original anticipated economic life of TAPS was 25 years. However, due to enhanced recovery techniques, revised reserve volumes, and development of new fields, TAPS is now being positioned to operate for another 30 years.

To support this operational commitment, Alyeska Pipeline Service Company (Alyeska) and the TAPS Owners have initiated a redesign of the pipeline pump stations and control systems. The Valdez Marine Terminal and SERVS are also being studied, but these studies are not as advanced as the pipeline. Preliminary engineering for the pipeline pump station redesign was completed in 2003 and the TAPS Owners are evaluating the results.

TAPS was originally designed for a 1.5mmbopd throughput (excluding Drag Reducing Agents) and has been operated for 25 years using personnel to monitor pipeline and pump station operations. Although this practice has worked well, it is no longer cost effective. Current technology used by other pipelines all over the world includes electronic monitoring and control systems that are more efficient and reliable.

The pipeline reconfiguration project is a proposal to utilize those technologies to enhance TAPS operational efficiency. This "proven technology" will reduce future operating costs and maximize efficiency far into the future. None of these changes compromise safety or operational integrity. In fact, safety, operational integrity, and environmental performance will be enhanced with Strategic Reconfiguration.

Background for Pump Station Strategic Reconfiguration (SR)

For several years, Alyeska has been engaged in engineering studies to identify ways to improve operational efficiency through technology upgrades, increased use of automation, and reduction of infrastructure to minimize transportation costs and extend the economic life of the pipeline and North Slope oil fields. This will be accomplished through equipment upgrades and the resulting reductions in Operations and Maintenance (O&M) costs.

The SR pipeline study was formalized in 2001 when an Alyeska Reconfiguration Studies team and TAPS Owners planning team jointly examined eleven proposed alternatives. The initiative was complete in January 2002 with a recommendation of two strategies for further study, electrification and hybrid (see following page). A third option, direct drive turbines, was later added to the list.

Electrification is the installation of electrically driven crude oil pumps at certain pump stations combined with increased automation and upgraded control systems. It includes a dramatic reduction of utility systems and associated facility infrastructure and allows un-staffing of pump stations.

The hybrid option strategy was an attempt to make best use of existing equipment while achieving the SR objectives of simplified infrastructure and reduced O&M costs. It consists of automation of existing crude pump drive packages and utility systems and includes the same upgraded control systems that would be installed for electrification. This option does not have capacity flexibility to accommodate future throughput changes and has been abandoned as an alternative.

The direct drive turbine option, a variation of the electrification theme using gas turbines instead of electric motors, incorporates many of the same concepts but is mechanically more complex and slightly less reliable. At the current stage of engineering, adopting this alternative implies expensive engineering and construction delays and therefore this alternative was abandoned.

Costs for each option were compared to an inertia case, which consists of the current practice of maintenance and equipment lifecycle replacement. This is the status quo case and subjects Alyeska to the lowest operating reliability and highest ongoing O&M expense of any alternative.

TAPS Construction History and Reliability

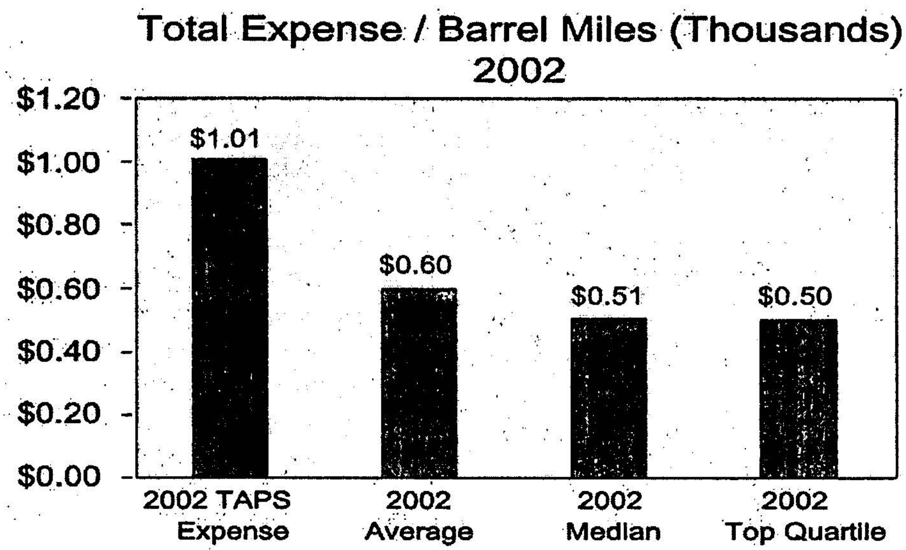
One of the first challenges in developing the North Slope fields was creating a transportation system to move the vast reserves of the Sadlerochit field in Prudhoe Bay to market. Engineers decided a large-diameter pipeline from the North Slope to a marine tanker loading facility at an ice-free port was the answer. Alyeska Pipeline was created to construct, operate and maintain TAPS for the Owner companies. Originally eight in number, TAPS Owners are now BP Pipelines (Alaska), Phillips Transportation Alaska, ExxonMobil Pipeline Co., Williams Alaska Pipeline Co. (whose interest is currently under a purchase agreement with Koch) and Unocal Pipeline Co.

Despite many engineering, political, and regulatory hurdles and a cost of more than $8 billion, construction of TAPS was completed in June 1977. The first oil left Pump Station 1 on June 20, 1977 and the tanker *ARCO Juneau* steamed out of the Valdez marine terminal laden with Alaska North

Slope (ANS) crude on August 1 that same year. Since then, more than 14 billion barrels of ANS crude have been transported through the pipeline, with throughput peaking in 1988 at nearly 2.1 million barrels per day. Current throughput is relatively stable at just under 1 million barrels per day.

While reliability throughout the history of TAPS has averaged well above 99 percent, other pipelines have achieved this same reliability through the use of modern technology and automation. Due to steadily increasing regulatory oversight, aging of the system, increase in personnel costs and inherent inefficiencies in original design, TAPS has risen in cost per barrel mile to lead its U.S. large pipeline peers in the transportation cost category.

The chart below shows how TAPS compares to other large pipelines based on benchmark data obtained from the Association of Oil Pipelines (AOPL).



Preliminary engineering studies indicated the electrification option is the only alternative satisfying the project objectives of reliability, efficiency and cost-versus-savings. Direct drive turbines is the next best alternative, but has slightly reduced reliability and savings coupled with increased on-going maintenance. The hybrid case did not meet project objectives. Recommended implementation strategies for pipeline electrification are outlined as follows.

- Power generation upgrades, electrification and automation of Pump Stations 1, 3, 4 & 9.
- Consider removal, retirement and disposal of all above grade unused equipment and facilities at Pump Stations.
- Install control and communication modules at Pump Stations.

Electrification satisfies the following objectives established under Strategic Reconfiguration:

- Maintains safety and operational integrity.
- Improves operational efficiency and environmental performance.
- Shows highest economic rate of return with the least economic risk.
- Allows unstaffing of pump stations through remote control capabilities.
- Is scalable to future throughput requirements.
- Will maintain required reliability through use of technology rather than on-site staff.
- Is proven technology currently in use in the industry.

Pump Station Reconfiguration-Electrification Major Project Milestones

- Workforce plan approved – 4Q2003
- OSCP amendments approved – 4Q2003
- SCADA upgrade complete – 4Q2004
- Communications module installation complete – 4Q2005
- PS control systems upgrade complete – 4Q2005
- PS1, 3, 4 & 9 electrification complete – 4Q2005

Methodology for Project Savings/Cost Determination

Alyeska used a rigorous methodology for the development of project scope and determining costs/savings. A strategic plan, developed by Alyeska's Planning Team, was adopted by Alyeska management and the TAPS Owners. This process resulted in two options for which conceptual design was completed: electrification/automation and inertia. Third party validation confirmed the cost and concept of each option and identified electrification/automation as the best choice. From this work, 2003 long range planning assumptions were defined and used as the basis for company-wide planning.

The Alyeska organization and the SR project team then embarked on parallel paths while working toward a common goal. The project team formalized project scope, completed preliminary engineering, developed an operations philosophy and finalized project costs. Simultaneously, company managers identified staffing requirements, major maintenance that could be eliminated, and determined project savings. Benchmarking with industry peers and verification by cross-functional groups within the company validated outcomes and identified additional savings opportunities and other synergies. Final assurance included executive review, approval and commitment.

1.3 Electrification: Old versus New

Although electrifying pump stations sounds complex, it is really a straightforward solution to achieve the project objectives of efficiency, cost reduction and extension of economic life of the system. This section compares facilities and process equipment installed on TAPS now to post-electrification and discusses changes to Alyeska's O&M philosophy.

Description of TAPS

TAPS is a crude oil transportation system that begins at PS1, the gathering and storage center for all North Slope producers, and terminates at a marine terminal storage and tanker loading facility located in Valdez on the shores of Prince William Sound. The 48-inch pipeline is 800 miles long, crosses three major mountain ranges, 34 major rivers and achieves a maximum elevation of 4,379 feet at Atigun Pass located 166 miles south of PS1. Of the 800 miles, 420 are above ground and 380 are buried, with 62 RGVs installed to reduce spill volumes in the event of a breach in the pipe.

Twelve pump stations are designed into the system although not all are active pumping stations. PS5 is a relief and reinjection station while PS11 is installed with mainline isolation valves only as its additional pumping capacity was never required. Of the remaining ten stations with pumping

Critical Energy Infrastructure Information

quantities of Drag Reducing Agent (DRA) were injected upstream. However, DRA is expensive and operating PS7 is more economical to meet horsepower and maximum operating pressure requirements at current flow rates.

As North Slope production began to drop off in the mid-1990's, full pipeline design capacity was no longer needed. As a result, five pump stations are currently off line in a stand-by configuration called rampdown. PS8 & 10 were ramped down in 1996, PS2 & 6 in 1997, and PS12 in 2003.

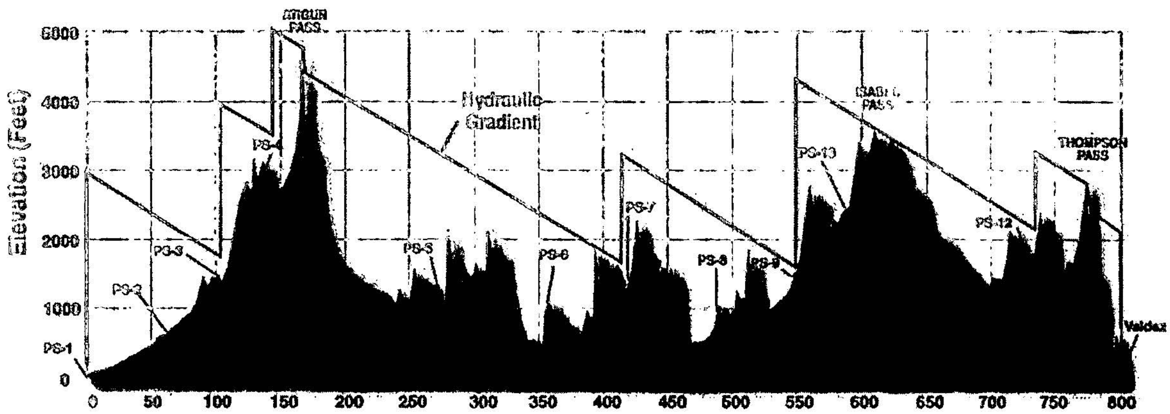
Pump Driver Package: Old Vs. New

The pump driver package installed on TAPS is a reliable but dated Avon gas turbine coupled to either a Byron-Jackson or United centrifugal pump. PS1, 3, and 4 drivers use natural gas as a fuel source while PS7 & 9 use liquid turbine fuel.

Each station with pumping capability has three such drive packages installed with the exception of PS2 & 7, which have two. During peak throughput in the late 1980's there were no spare drivers on TAPS; every installed unit was needed to meet horsepower requirements for the high flow rates. Although dependable over the years, these drive packages and appurtenances are complex and labor intensive to operate and maintain to the standards required on TAPS.

Electrification will replace the existing pump driver packages with skid-mounted electric motors and modern centrifugal pumps. The engineered design is very flexible and allows for many of these skids to be installed in parallel to accommodate throughput rates up to system capacity of over 2 million barrels per day (Mbpd). Initially, three of these driver packages will be installed at PS1, 3, 4 & 9; this configuration supports throughput up to 1.12 Mbpd. Adding two more skids at each location will provide 1.5 Mbpd capacity. Taking units off-line will allow reduced throughput rates in the several hundred thousand barrel/day range while remaining within acceptable equipment operating parameters. Variable frequency drives (VFD) will be installed for control of the motors; replacement motor control centers (MCC) will handle power distribution.

Trans Alaska Pipeline System
Elevation Profile



Power Generation: Old Vs. New

Due to the remoteness of TAPS, most pump stations need to generate their own electrical power. This is currently accomplished with various numbers of skid-mounted 450 kilowatt Garrett and 800 kilowatt Solar turbine generator packages. Due to obsolescence and age of equipment, it is increasingly difficult to maintain these generator sets. Under electrification, PS1 has the option to tie into the existing North Slope grid for power needs or self generate. Power generation at PS3 & 4 will be accomplished with modern skid-mounted turbine generators while PS9 will purchase power from a local utility. There will be no change at PS7.

PS1, 3 & 4 use processed natural gas received from North Slope producers for general fuel needs such as mainline pump drivers, power generation and facility heating. Following reconfiguration, this fuel gas will still be used for primary power generation.

Process Control: Old Vs. New

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Telecommunications: Old Vs. New

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Fire Systems: Old Vs. New

Fire detection and suppression is particularly important on TAPS due to remote facility locations. Fire systems currently installed at the pump stations include various combinations of smoke, gas and flame detectors that initiate suppression actions and equipment shutdowns; flooding agents include water, halon and foam. Many of these systems are designed around occupancy requirements of a staffed facility and will not be needed following reconfiguration.

Maintaining these systems has become particularly problematic in recent years because original pipeline design included large enclosed process areas (see photo). Fire codes have changed since TAPS was engineered. This has created compliance issues that can be more effectively resolved with new equipment.

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Housing, Utilities and Staffing: Old Vs. New

Even though some remote control capabilities are designed into TAPS, the pump stations are currently staffed 24 hours a day, 365 days a year due to equipment monitoring requirements, remote control system deficiencies, and oil spill response needs. This necessitates the pump stations to operate and maintain a wide range of life support utility systems such as potable water, wastewater, heating and ventilation, waste disposal, food preparation appliances, and vehicle refueling and maintenance. The extreme Arctic conditions under which these systems operate make maintenance difficult and expensive.

Additionally, field staffing requires a large infrastructure for such things as living quarters, office space, telephone and data systems, and a materials supply network. Remote airports are required, emergency evacuation must be considered, medical care provided and even such things as mail and package delivery accomplished. In essence, a typical pump station is equivalent to a small city with a resident population of 40 – 50 with peaks as high as 130 during busy project seasons.

With the application of new technology, that can be changed. The top photo below shows an aerial view of Pump Station 3 in its current configuration. Contrast that to the photo underneath, which is what PS3 could look like after SR and possible later removal of unused equipment when approved by Owners and regulators. It is easy to see the impact of Strategic Reconfiguration to installed infrastructure and facilities. There will be fewer buildings in use, simplified communications and process control, upgraded pump/driver packages, and no assigned staff. A reduction of approximately 15 percent of the total current workforce is possible because of the reduced workload.

New Technology – Less Infrastructure – Same Throughput

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Strategic Reconfiguration represents a 30-year leap in technology. This new technology requires far less infrastructure, and operating facilities are greatly simplified.

At top left is an aerial view of PS3 in its current configuration. Note the large number of buildings, interconnecting hallways, and outlying support facilities. Because pump stations are currently staffed around the clock, on-site housing is required, creating the need for life support systems such as water and wastewater treatment, heating, food preparation, trash incineration, fire suppression, vehicle maintenance and additional power generation.

By implementing modern technology, the need for full-time staff is eliminated. This means the decommissioning or removal of housing units, reduction of utility systems, and elimination of support facilities.

The lower photo depicts PS3 post-reconfiguration; as can be seen, the changes are significant. TAPS-wide, at least 75 buildings could be decommissioned and 27 more could be simplified. Removing work from the system provides significant, sustainable cost reductions.

Synergies: OSCP/Support Services/Maintenance

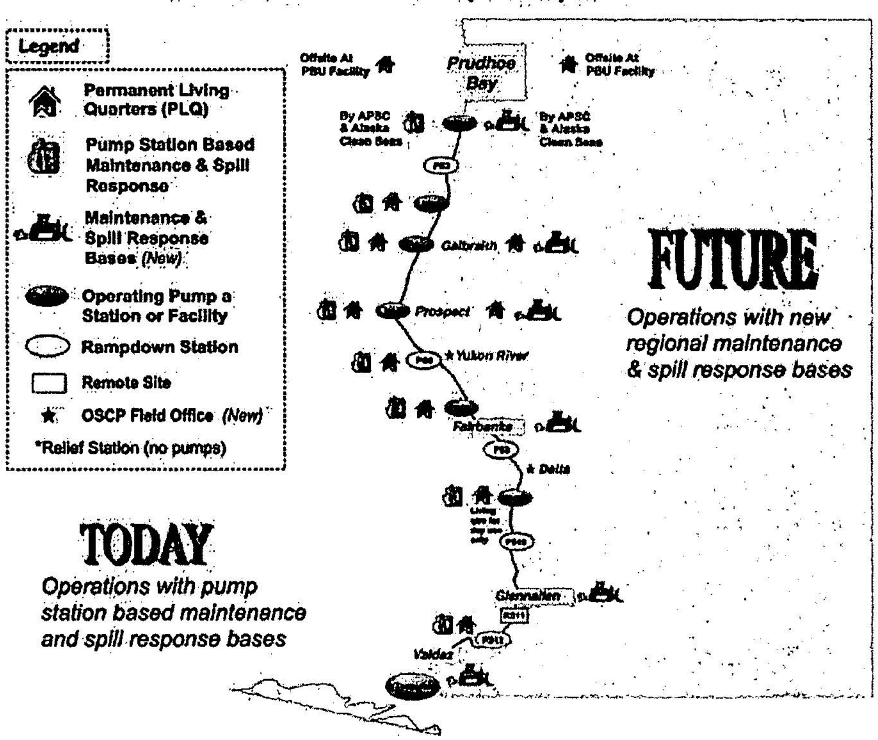
Although pipeline SR as a stand-alone concept is strictly a technology driven solution to achieve efficiency and cost savings, there are several other business considerations that, when combined with SR implementation, will produce increased operating and business efficiencies. These synergies are outlined below.

- Oil Spill Contingency Plan (OSCP) amendments accommodate unstaffing of remote facilities while maintaining and/or improving response capabilities using regional response bases and additional pre-deployed equipment. Although the total number of staff in the field will be reduced, the number of initial responders will not change.

- Operations philosophy changes as a result of electrification allow elimination of all operation technician functions as well as a greatly reduced infrastructure of buildings, services, and field-based support groups.

- Maintenance philosophy changes allow centralized dispatch for scheduled maintenance. This approach creates efficient use of personnel while supporting OSCP amendments and ongoing Right-of-Way (ROW) maintenance.

TAPS Maintenance and Spill Response



- The scalability of the electrification solution accommodates a wide range of future increases or decreases in throughput and allows those changes to be accomplished at a much lower cost.

Critical Energy Infrastructure Information

Details of the design can be found in the Preliminary Engineering Design Report:

Prelim Eng Main Doc.pdf

2. Business Case

2.1 Strategic context and Business Objectives for the Alaska Business Unit

As described in the Pump Station Electrification Appraise FM of March 2003, Alaska's role in BP's portfolio is to provide a stable production base and cash flow to fuel growth elsewhere in the business while improving margins and returns. Driving cost savings in TAPS is a key element in delivering margin improvement of BP's North Slope production.

Over the past three years the TAPS Owners and Alyeska have studied a number of potential business efficiency opportunities. Preliminary engineering studies confirmed that Pump Station Electrification is the single largest driver of pipeline cost improvement and efficiency. Preliminary engineering studies have also confirmed electrifying and automating all 4 pump stations will allow Alyeska to eliminate over 285 full time positions, many of those in field locations where wage and locations premiums are very high. Currently, remote crews at these pump stations require expensive catering, transportation and other costly support services systems. Eliminating these positions translates to an annualized expense savings improvement of over $41mm gross (+$16mm net BP) by 2007 over APSC 2003 Base O&M.

2.2 Project Economics

Assumptions:

Electrification was modelled against a "Base/Inertia Case". The Base Inertia Case assumes continued use of the Avon-driven pumps, normal upgrades to remaining facilities and a reasonable allowance for continued operational improvement. In 2012 O&M is increased by $4m annually to account for expected higher annual maintenance caused by turndown effects.

The Electrification case assumes self generation at PS 1, 3 & 4. It assumes GVEA power is supplied via the existing power grid to PS 9.

The Electrification case assumes that beginning about 2009 the APSC annual License to Operate Capital will decrease about $6m under the Base/Inertia Case due to reduced Corporate Projects. This reduction is consistent with the capital funding expected in the APSC Long Range Plan and matches the BP estimate for Non-Pump Station related capital projects after electrification.

The Electrification Case assumes P Highly Confidential Material Redacted Savings and P Highly Confidential Material Redacted Capital. It also assumes Highly Confidential Material Redacted of the annual O&M savings accrue starting in 2006, with full savings in 2007. It assumes some buildings at the reconfigured pump stations can be abandoned in place.

Highly Confidential Material Redacted Inflation was applied to O&M and Capital costs. Throughput was assumed to be declining at a Highly Confidential Material Redacted annual rate (and used to calculate fuel savings).

BP's equity in TAPS is 46.9% and our throughput share is assumed to average Highly Confidential Material Redacted over the period of evaluation. This is a cost reduction investment hence there is no sensitivity to oil price.

Sources of Value:

BP value is manifested in improved wellhead netback prices due to reduced tariffs. Summary economics are presented in the table below.

Summary Economics (Electrification vs. Base Case) [redacted]

	Sanction Capital (Net) $m	Post Savings Thru '03 Gross (Net) $m
Midstream	81	32 (12.7)
Upstream	--	--
AKBU	81	32 (12.7)

Highly Confidential Material Redacted

[redacted]

Highly Confidential Material Redacted

Financial Impact (Electrification vs Base Case) $m [redacted]

Alaska BU	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Tariff Change ($/bbl)	$0.00	$0.05	$0.06	($0.09)	($0.10)	$0.00	($0.05)	($0.12)	($0.21)	($0.36)
Opex Savings	1.8	4.3	11.9	24.3	23.8	24.1	21.5	22.3	20.5	27.6
Incremental Capex *	(47.4)	(48.3)	2.6	2.6	1.2	3.7	2.8	2.5	2.8	4.6
Post Tax Cash Flow	(37.4)	(44.3)	13.9	25.4	15.7	16.9	17.8	18.8	16.9	23.5
RCOP Impact	1.1	1.2	6.9	17.5	16.8	19.0	16.4	17.2	15.2	21.4
Net Income Impact	0.6	0.6	4.3	11.2	10.7	12.2	10.5	11.0	9.7	13.7
NI/boe	$0.01	$0.01	$0.05	$0.14	$0.12	$0.13	$0.12	$0.15	$0.15	$0.23

* Incremental Capex includes life cycle replacement expenditures.

PS 1 and PS 9 Power Options

Optimizing the investment and commercial terms for power purchases at PS 1 and PS 9 are key drivers of value. At PS 9 Golden Valley Electric Association (GVEA) will provide commercial power through a utility grid. Delivery of power to PS 9 will require GVEA to upgrade their transmission system. GVEA will pass on that cost to APSC either through an installation fee or through a rate premium. Negotiating the cost of this upgrade into the power rate saves $10.6m gross in CAPEX. At PS 1, sharing power with the Prudhoe Bay Central Power Facility could save $16m gross in CAPEX. The recommended target case assumes PBU will provide no power since the PBU Owners have failed to deliver a Memorandum of Understanding for Power Costs.

Expected Value "Base Case" for Subsequent Value Tracking

Details of the expected Value Case are presented below. Electrification investment spending occurs primarily in 2004 and 2005.

Table 2. Investment Profile

APSC Investment Profile (APSC Gross CAPEX)	2004	2005	2006	2007	2008	2009
Inertia Base Case Capex	53.8	61.3	60.4	59.2	59.3	60.0
Elect Investment Case Capex (21mW, no LB CAPEX)	147.0	176.1	58.0	54.0	58.0	57.0
Net Incremental Investment	93.2	114.8	-2.4	-5.2	-1.3	-3.0

Savings delivery is best tracked on a gross APSC basis. The case below assumes that the Incremental O&M Savings is deliverable through electrification. Note that the underlying performance improvement is about $41m.

Table 3. Savings

APSC Gross Spending/Savings Profile	2004	2005	2006	2007	2008
Inertia Case	451.9	480.3	471.6	420.4	403.2
Electrification Case (17 mW, no LB CAPEX)	447.2	456.2	426.3	355.3	343.3
Avoided Major Maintenance	4.6	23.9	21.5	18.4	18.7
Incremental Annualized O&M Savings	-0.1	-0.1	-23.9	-46.6	-41.3

2.3 Principal Commercial Risks

Regulatory: Any major change in TAPS facilities requires Joint Pipeline Organization (JPO) and Alaska Department of Environmental Compliance (ADEC) approval.

The JPO has been supportive of the project and has confirmed through its own benchmarking exercise that TAPS electrification will better align the operation with other North American pipeline systems in terms of facilities and operations. The Argonne Benchmarking Study is attached:

JK001.pdf

Conditional approval was received from both agencies as of December 31, 2003.

JPO Finding of No Significant Environmental Impact:

Fonsi.pdf

JPO Notice to Proceed with Stipulations:

03-009RN.pdf

ADEC approved the OSCP on December 31 with "Specified Conditions". The "conditions" have no impact on project economics or schedule.

ADEC OSCP Approval:

JK001.pdf

RCA Issues:
We have considered the risk that the Regulatory Commission of Alaska (RCA) will exert approval authority over the proposed facility changes. The Owners have worked to mitigate this risk by clarifying to the RCA the separate nature of Electrification and the decision to remove ramped down facilities. Additionally, BP has prepared a legislative solution in case the RCA seeks to intervene. Should the RCA move to disallow Electrification cost recovery on intrastate shipments, such costs would be rolled over to our interstate tariff for recovery hence there should be minimal impact to value.

Dismantlement, Removal and Restoration:
Costs associated with dismantlement, removal and restoration (DR&R) of the affected stations (1, 3, 4 & 9), estimated at $10m ($4.7 m BP net), are excluded from the economics. These costs are

deemed discretionary, as the associated structures can be abandoned in-place until such time as the TAPS Owners move forward with a sanctioned DR&R project. There remains a minimal regulatory risk that the TAPS Owners could be challenged to remove idle equipment from TAPS.

Sanction/Schedule/Governance: Achieving sustainable savings from manpower reductions requires executive will. Given our governance role through the Owners Committee, BP is well positioned to ensure the proper focus and incentives are in place to assure delivery. As indicated in the graph below, a delay in delivering costs savings by one year could result in significant BP NPV loss. The Alyeska President is firmly committed to achieving and sustaining projected cost reductions with many of the organizational realignment activities already underway in anticipation of sanction.

Management of Change: Assuring successful cutover to new operating facilities is an important factor for staff and regulatory support. We do not have a robust transition plan in place today. However, Alyeska has appointed a senior leader with single point accountability to create a comprehensive MOC plan. Additionally, BP will elevate MOC focus to the Owners Committee to ensure executive ownership.

Project Cost Management: Cost and scope control are critical considerations for delivery. Extra measures are in place to ensure that the project is ring-fenced from other project spending to avoid scope-creep or inappropriate time-writing to the project. APSC has appointed a commercial leader to manage project logistics, SCM and provide robust cost controls. BP will require transparency in monthly project financial reports to the TAPS Owners.

Higher Grid Power Costs – The cheapest source for electrical power at PS 1 is spare capacity from the Prudhoe Bay Unit Central Power Station, however only about 4 MW are available. The PBU Working Interest Owners have failed to deliver requested commercial terms to APSC. As a result, the project assumes all PS 1 power will need to be self-generated.

Savings Delivery – About 50% of the anticipated savings is derived from the reduction in the support organization due to fewer field-operating personnel and less anticipated engineering support. Achieving these savings requires a major manpower severance program and careful management of change to ensure that operating integrity is not sacrificed. It is also important to ensure that all expected savings are captured. Roles and accountabilities in the re-organization have been defined. A severance plan has been created.

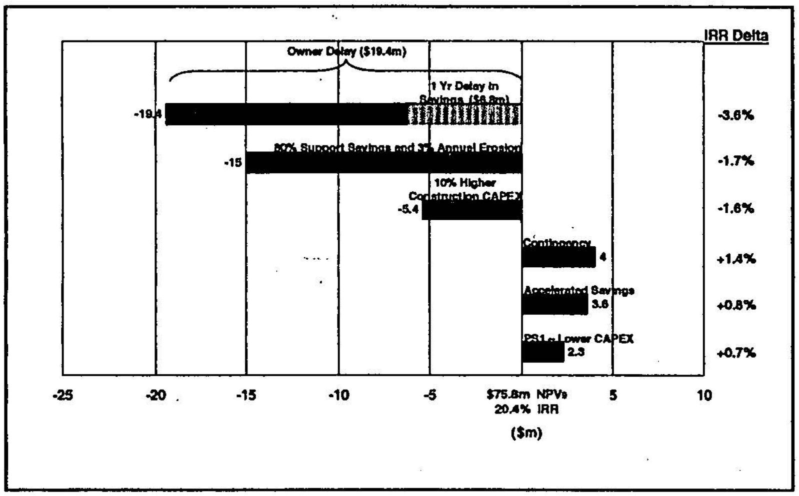
Other Risks-Alyeska has created the following detailed risk mitigation plans to assure operating integrity and safety including:

Safety Management Plan
Environmental Management Plan
Workforce Reduction Plan
Critical Skill Retention Study and Plan
Project Execution Plan
Quality Management Plan

Technical Risk Issues and Track Record – The technology to automate and electrify pump stations is not new, virtually all of Alyeska's peers in the recent AOPL Pipeline benchmarking study have automated pump stations. The primary driver of cost difference between TAPS and AOPL comparator Pipelines is driven by this lack of automation.

2.4 Economic Sensitivities

Below is a summary of value adding options/Economic Sensitivities and their impact on project economics:



Sensitivities & Value Adding Options / Delivery Risks

- <u>Owner Delay</u> – Delay would result in loss of value due to opportunity loss, addition of mandatory life cycle spend that had been previously deferred, loss of accelerated federal tax depreciation benefits, and additional project team cost.
- <u>Under-delivery of Savings and Erosion</u> – Executive will is required to deliver and sustain projected cost savings. Management commitments and governance processes are in place to assure delivery.
- <u>Capital Cost Overrun</u> – Adequate FEL has been performed and project management systems are in place.
- <u>Contingency/ Value Engineering</u> – Delivery of project contingency capex savings through ongoing value engineering processes.
- <u>Accelerated Savings</u> – Early delivery of organization opex savings pre-startup.
- <u>PS1 Lower Capex (PBU Power Purchase)</u> – Option to purchase part of Pump Station 1 power requirement from PBU.

2.5 Key Project Milestones and Schedule Overview

Milestones

BP SET Approval	February 2004
TAPS Owner Approval	March 2004
Award of Major Contracts	April 2004
Facility foundation work	Summer 2004
Remote Communication Module tie-in	Summer 2004
Module Shipment and connection	Spring 2005
Start-up and Testing	October 2005
Commissioning	December 31, 2006

Project Schedule Overview

The project is operating on a tight schedule in order to meet fire system commitments and to obtain tax benefits by December 31, 2004. Realizing organizational savings as quickly as possible is leveraging.

Delay of the project will result in lost O&M savings, lost tax benefits, increased major maintenance costs (including fire and gas system upgrades), and increased program management costs. The unfavorable impacts of a one-year delay are estimated in the range of $40 million to $60 million.

Key deliverables are as follows. See the attached project schedule for additional details.

AFE Approval	March 1, 2004
Authorize equipment manufacture	March 1, 2004

Tie-ins (2), RD Comm. Modules	Summer 2004
PS 4, PS 5, PS 7 & PS 9 foundations	Summer 2004
Major equipment in fabrication shops	Fall 2004
Module piling at PS 1 & PS 3	Winter 2005
Module shipment, start interconnect	Spring 2005
Mechanical Completion	October to December 2005
Startup and Commissioning	November 2005 to Jan 2006

3.0 Execute Phase Planning

3.1 Project Execution Strategy and Plan

The project execution plan outlines the purpose of the project, the organization of the project management, and is composed of sub-plans in safety, Construction, Procurement, Environment and Quality Management.

It defines the project scope, describes the physical changes in the facilities, describes the "Project Success Factors" and sets project cost targets.

The execution plan also defines the roles and accountabilities for project personnel. Details of the Project Execution Plan can be found in the attached document:

Project_Execution_Plan.pdf

3.2 HSE Management and Issues

HSE Planning and Strategy

A complete Environmental Management Plan was developed for Pump Station Electrification that describes the permitting and compliance management processes required for executing the Pipeline Electrification Project. It is included below:

PEP HSE p8-10 .pdf

An Environmental Assessment (EA) was also completed and is provided in the Reference Documents. The EA concluded that Pump Station Electrification project will significantly reduce the environmental impact of the TAPS System.

Env Mgt Plan Rev 0
DRAFT Nov 7...

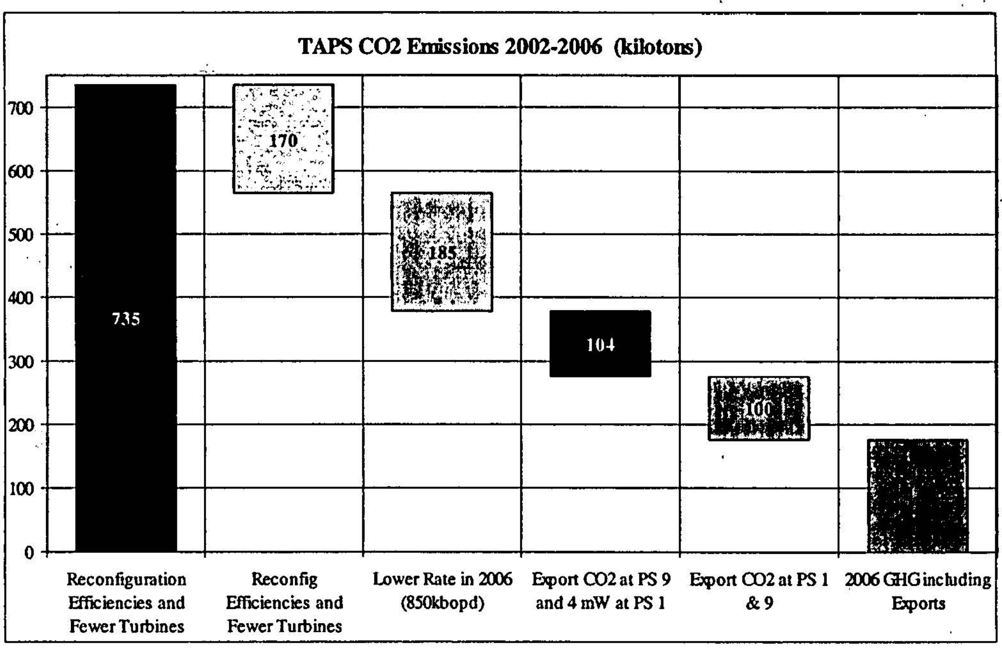
A complete Safety Management Plan has been created for the project including a preliminary HAZOP, Safety Integrity Level analysis and Risk Assessment. The details of the HAZOP are included in the following document:

Hazop.pdf

Emissions Reductions

This project will significantly reduce the physical footprint of TAPS pump stations, eliminate about 50% of the current TAPS CO_2 emissions and improve safety by reducing manpower in the field where historically the highest "recordable incident" rates have occurred.

A significant reduction in air emissions will occur when the Rolls Royce Avon turbines are eliminated:



These modeled Carbon Dioxide reductions were estimated using an APSC fuel consumption model.

3.3 Contracting Strategy

During Preliminary Engineering a contracting and procurement strategy was developed for the execution phase of this project. The details of that plan can be found in the following document:

PEP Contracting Strategy p28-35.pdf

Contracting Plan - SRP 10.02.0...

3.4 Execution Organization

The project organization developed to execute the final design and construction of the Reconfigured Pump Stations was developed in the Preliminary Engineering phase. Organization charts representing those organizations can be found in the following document:

PEP Exe Org Exhibit 1-2-3 p65-67.pdf

4.0 "Operate Phase" Planning

4.1 Redefining the operating organization:

The shift to automated pump stations requires addressing 3 groups of operating personnel, the pump station operators, pump station maintenance personnel and pump station oil spill support. The pump station operators will be replaced by telemetry and station controls. They are eliminated from the future organization.

Oil Spill response will be regionalized as described below. No significant reduction in OSCP staff will occur however they will be redeployed along the line.

4.2 Oil Spill Plans

Since construction, TAPS utilized Oil Spill Responders and equipment staged at operational Pump Stations along TAPS. De-manning the pump stations requires redefining the oil spill contingency plan to be able to provide the same level of oil spill response by responders now based in Regional Oil Spill Centers rather than at the pump stations. ADEC and the JPO have

Critical Energy Infrastructure Information

The details of the Regionalized Oil Spill Plan can be found in the attached document:

(Insert Oil Spill Plan)

The new plan has no reduction in spill responder staff, and no net reduction in response time for the secondary responders. The relocation of staff to urban centers and a transition of some of the staff to urban work schedules will reduce costs.

Both the JPO and ADEC have conditionally approved the Regional Oil Spill Plan despite public criticism from an APSC Maintenance Supervisor. That criticism was directed at training, supervisor/worker ratios, initial response capabilities and equipment staging locations. Both

APSC and the JPO seriously considered the issues raised and many were either addressed by APSC internally or addressed by the JPO in their conditional approval letter.

4.3 Regionalized Maintenance

Pump Station maintenance personnel will also be re-deployed through a "regionalization". Maintenance Centers will be located at Prudhoe Bay, Galbraith, Prospect, Fairbanks, Delta, Glenallen and maintenance staff will be withdrawn from the Pump Stations.

5.0 Assurance:

Throughout 2003 APSC, and their contractors (SNC-Lavalin and Hinz), undertook a series of peer reviews with the TAPS Owners and other appropriate oversight groups. These included three BP "No Wreck Reviews" (June, October and January 2004), two IPA FEL reviews (November and January 2004), a "Value Engineering" challenge session (December 2003) and five cost review/challenge sessions. Those assurance activities are described below and documented in Section 8 (Reference Documents).

5.1 Value Engineering

Value Engineering Overview
A Value Engineering Study was completed for Alyeska Pipeline Services Company (APSC) on the Strategic Reconfiguration Project, Pump Station Electrification and Control System Automation scope, for the Trans Alaska Pipeline System (TAPS).

The initial Value Engineering Study was completed on November 5th, 6th and 7th, 2003. The Preliminary Engineering Design phase of the project has been completed and the project team is working on a transition engineering phase pending project approval by the TAPS Owners.

The objectives of the VE Study were to:

A. Identify cost saving opportunities and improvements to the value of the design.
B. Select the minimum scope necessary to reduce operating costs by de-manning pump station facilities.
C. Do so without compromising reliability, availability, safety and system integrity goals established for this project.

Value Engineering Key Results
The VE team prepared 56 idea proposals and based on the proposal evaluations made recommendations to APSC Project Management. Of the 56 idea proposals produced, 8 idea proposals were deferred for further evaluation during detailed engineering, 27 were rejected and 21 were accepted.

The successful implementation of these 21 idea proposals could result in a total savings of $18,033,000.

The detailed Value Engineering Report:

VE Final Report.doc

5.2 No Wrecks

At the request of BP, APSC held a series of "No Wreck" reviews in the BP format with "No Wreck" tools as guides to facilitate peer discussion of the Electrification Project.

Three "No Wreck Reviews" were held, one in June 2003 to get an early view on project status and to ensure that key risks were identified and addressed in the Preliminary Engineering Studies. This meeting identified gaps associated with operations integration and important risks associated with regulatory issues (Regulatory Commission of Alaska).

The second "No Wreck" was held in October 2003 and meant to determine how close the project was to sanction and to identify gaps to close before 1Q 2004 sanction reviews began. This review helped to more clearly define the TAPS Owner expectations around risked costs, Value Engineering, and the separation of the project from other ongoing reconfiguration activities.

A final "No Wreck" was held in January 2004 as a final test to determine if the project had adequately addressed the October No Wreck feedback and to prepare a forum in which technical experts could review the preliminary engineering studies and if appropriate endorse the project.

A summary of the final Jan 2004 "No Wreck" feedback:

TAPS One pager
.doc

5.3 Head of Discipline (HOD) Review and TVP Endorsement

Concurrent with the final "No Wreck Review" technical endorsements were received from EPTG Operations, Energy Efficiency, HSE, EPTG rotating equipment specialists, EPTG electric motor specialists and EPTG Projects. Those endorsements are included in the document above. Detailed feedback from the HOD Reviewers is included in the Powerpoint presentation below:

TAPS Review Peer
Feedback.ppt ...

5.4 IPA

Two IPA reviews were held. The first was in November 2003 when very little formal documentation for the project existed and again in January, 2004, after virtually all of the Preliminary Engineering documentation was complete.

The January IPA review revealed an FEL Index of 5.0. That FEL index level is consistent with well planned major projects and benchmarks very favorable versus other successful BP Major Projects.

IPA Final Report 2.16.04.pdf